S. Hrg. 107–854

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

HEARING

BEFORE THE

COMMITTEE ON GOVERNMENTAL AFFAIRS UNITED STATES SENATE

ONE HUNDRED SEVENTH CONGRESS

SECOND SESSION

NOVEMBER 12, 2002

Printed for the use of the Committee on Governmental Affairs

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CONTENTS

WITNESSES

Tuesday, November 12, 2002

Alphabetical List of Witnesses

APPENDIX

APPENDIX

Volume I

Materials Submitted for the Record by Chairman Lieberman

Supporting Documents (footnote numbers indicate footnote in Majority Staff Memorandum where document was first referenced)

Page

Volume II

Page

Volume III

Volume IV

Materials Submitted for the Record by Ranking Member Thompson

EXHIBITS CONTINUED—VOL. II

Committee on Governmental Affairs
EXHIBIT #A-32

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

INITIAL REPORT ON

COMPANY-SPECIFIC SEPARATE PROCEEDINGS

AND GENERIC REEVALUATIONS;

PUBLISHED NATURAL GAS PRICE DATA;

AND ENRON TRADING STRATEGIES

FACT-FINDING INVESTIGATION OF

POTENTIAL MANIPULATION OF

ELECTRIC AND NATURAL GAS PRICES

DOCKET NO. PA02-2-000

August 2002

Prepared by the Staff of the
Federal Energy Regulatory Commission

Table of Contents

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

EXECUTIVE SUMMARY

In this initial report, the Staff of the Federal Energy Regulatory Commission (Commission) presents to the Commission, the Congress, and the public its initial report on its investigation in Docket No. PA02-2-000 and its findings and recommendations with respect to (1) the initiation of separate proceedings to further investigate specific instances of possible inappropriate conduct by Portland General Electric Company (Portland), two other affiliates of Enron Corporation (Enron),[1] El Paso Electric Company (El Paso Electric), and Avista Corporation (Avista), and the initiation of generic reevaluations of the Commission's "simultaneous offer" rule; (2) publicly-reported California delivery point natural gas spot price data, including the use of such data in the California refund proceeding in Docket Nos. EL00-95-045 and EL00-98-042 now pending at the Commission; and (3) the impact of the Enron trading strategies (discussed in the previously released Enron memoranda[2]) on energy prices in the West.

This report reflects the views only of Commission Staff; it has not been considered by the full Commission. It is based only on the information that we have obtained and reviewed at this time; Staff continues to receive and review data including information relevant to the subjects covered in this report.

This report reflects information that was submitted to Staff under a claim of privilege pursuant to 18 C.F.R. § 388.112 (2002). Staff has made a good faith effort to ensure that none of the specifics of such material is being released to the public.

On February 13, 2002, in Docket No. PA02-2-000, the Commission directed Staff to gather information on whether any entity, including, but not limited to, any affiliate or subsidiary of Enron had 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 prices in

[1]The two other Enron companies are Enron Power Marketing, Inc. and Enron Capital and Trade Resources Corporation. Portland is a traditional public utility with captive ratepayers.

[2]As we discuss in more detail below, three memoranda describing Enron's electricity trading strategies were released by Enron's Board of Directors on May 6, 2002, and made publicly available on the Commission's web site. We refer hereinafter to these strategies as the "Enron trading strategies."

long-term power sales contracts. Staff was also directed to look into other factors that may have influenced contract terms.

As part of this ongoing investigation, Staff inquired into the characteristics of publicly-reported price data, including spot prices at California delivery points that are used to calculate the mitigated market-clearing price in the refund proceeding. This area of inquiry was in part prompted by allegations that Enron's bankruptcy had triggered a substantial fall in spot prices, which allegedly was evidence that Enron had manipulated those prices. While the Commission has no jurisdiction over trade publications, once a formal investigation was initiated, Staff was then able to conduct discovery of trade publications' procedures and practices with respect to reporting natural gas spot prices.[3] The results of this inquiry are contained in this initial report.

Staff, with the assistance of outside consultants who have expertise in electric and natural gas market issues,[4] is conducting a comprehensive investigation of a variety of factors and behaviors that may have influenced electric and natural gas prices in the West during 2000-2001. This is a time- and resource-intensive investigation which involves extensive data gathering and data analysis. To date, Staff has received in excess of 70 boxes of written material and in excess of 1,200 gigabytes (GB) of electronic data. In addition, Staff is sharing information with, and otherwise coordinating with, other investigatory agencies, including the Department of Justice, the Commodity Futures Trading Commission (CFTC), and the Securities and Exchange Commission (SEC).

Throughout the course of its ongoing investigation, Staff prioritized its efforts on those areas of inquiry that have the largest impact on customers, and one of those areas involves use of publicly-reported natural gas price data in calculating potential refunds in the California refund proceeding. Because of the large dollar impact and the fact that publicly-reported prices are a discrete subject readily separated from other areas of inquiry, Staff has accelerated the publication of its findings and recommendations on the use of published price data so that its findings and recommendations can be factored into the California refund proceeding. The now infamous Enron trading strategies have

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[3]*See* 16 U.S.C. § 825f (1994).

[4]The outside consulting firms are Aspen Systems Corporation (Aspen Systems) and Analysis Group/Economics (AG/E). Members of AG/E active in this investigation include Edward P. Kahn and Michael Quinn. Other outside consultants include Hendrik Bessembinder, Robert S. Pindyck, and Chester S. Spatt.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

adversely affected confidence in energy markets in the West. For this reason, Staff also presents its analysis and recommendations on the Enron trading strategies.

Staff reports the following principal findings and recommendations:

With respect to the initiation of separate, company-specific proceedings and generic reevaluations:

- **Staff recommends that the Commission initiate company-specific separate proceedings, in which specific instances of possible misconduct by public utilities can be further investigated and appropriate remedies imposed. These companies are three Enron companies (Portland, Enron Power Marketing, Inc., and Enron Capital and Trade Resources Corporation), El Paso Electric, and Avista. The specific instances of possible misconduct include: violations of the companies' codes of conduct and the Commission's standards of conduct; failures to make appropriate filings under sections 203 and 205 of the Federal Power Act (FPA); violations of the Commission's open access transmission requirements; and violations of minimum operating reserve requirements.**

- **Staff recommends that the Commission reevaluate the "simultaneous offer" rule that it uses to discipline affiliate transactions to ensure that it is effective and verifiable.**

With respect to natural gas price data:

- **Historically, the spot prices for natural gas at the California delivery points highly correlate with prices at producing basins and Henry Hub. During the months of October 2000 to July 2001 – the refund period in the California refund proceeding – the correlation was abnormally low. Since that time, the high correlation has resumed.**

- **Given the abnormal correlation for this isolated period, Staff attempted to independently verify the price data to assure that they are statistically valid, reliable, and free from the effects of price manipulation.**

- **The price data published in various trade publications share a wide range of generic characteristics, that is, characteristics common to all publications,**

common to price data for both electric and natural gas products, and common to the data for both daily spot prices and forward prices. These generic characteristics – and the availability of superior alternatives – raise serious issues concerning the continued use of the published natural gas price data for California delivery points for purposes of calculating the mitigated market-clearing price in the California refund proceeding.

- **At this point in time, no independent entity, such as this Commission, can verify the published price data. This is due, in part, to the reporting firms' status as non-jurisdictional entities as well as their legitimate desire to protect the confidentiality of their sources. Without knowing the source of the raw data, there cannot be any independent verification of the price data published by any reporting firm.**

- **The trade publications reporting spot and forward prices for both electric and natural gas products at California delivery points do not employ statistically valid sampling procedures or a systematic, formal verification procedure.**

X **While Staff is continuing to investigate whether there was actual manipulation of spot gas prices, we have preliminary indications that this may have occurred. Also, market participants had the incentive to manipulate spot prices upward for natural gas at the California delivery points.**

X **Enron OnLine (EOL) was a significant source of price discovery and formation and was potentially susceptible to manipulation by market participants.**

X **Staff concludes that the reported spot prices for natural gas at California delivery points are *not* appropriate for use in computing the mitigated market-clearing price and subsequent refunds in the California refund proceeding. Staff makes no conclusions as to whether these reported prices are inappropriate for structuring contractual provisions between two sophisticated parties bargaining at arms-length.**

X **While there may be other possible alternatives, Staff has focused its analysis on two of these, and we are recommending that refunds be computed based**

on the spot prices for natural gas reported at producing area pricing points, plus an allowance for transportation to California. Spot prices at producing areas can be independently corroborated because they correlate well with prices at Henry Hub, which has a deep and liquid futures market conducted on the New York Mercantile Exchange (NYMEX), itself a CFTC-regulated organized exchange. For purposes of the California refund proceeding, Staff regards spot prices at the producing areas to be superior to spot prices at Henry Hub, because natural gas at the producing areas is actually delivered to California, while natural gas from Henry Hub is not.

- **Generators with fuel costs in excess of Staff's recommended refund formula could apply for an uplift if it is demonstrated that the fuel costs were incurred based on arms-length negotiations with non-affiliated suppliers. This option will operate as a backstop to recover costs associated with scarcity.**

With respect to the Enron trading strategies:

- **While the exact economic impact of the Enron trading strategies is difficult to determine precisely, Staff concludes that these now infamous trading strategies have adversely affected the confidence of markets far beyond their dollar impact on spot prices. Staff will continue to investigate whether the Enron trading strategies had an indirect effect on other products such as long-term physical and financial contracts.**

- **Many of the Enron trading strategies may have been attempts to manipulate prices.**

- **The Enron trading strategies also may have involved deceit, including the submission of false information, including false schedules.**

- **Enron, as a corporate entity, displayed great eagerness to experiment with all aspects of market rules and protocols in an effort to "game the system" or to provide false information.**

- **Staff recommends that the Commission require that all market-based rate tariffs include a specific prohibition against the deliberate submission of false information, or the omission of material information, whether to the Commission or to an entity such as an independent system operator, regional**

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

transmission organization, public utility, or market monitor. This tariff requirement should be worded broadly to cover any and all matters relevant to wholesale markets, including maintenance and outage data, bid data, price and transaction information, and load and resource data. By including these specific prohibitions, any revenues generated from transactions associated with such activities would be subject to refund under the FPA. This refund provision would be an effective means by which the Commission can better ensure that the conduct of public utilities in consistent with the public interest.

- **Staff also recommends that all market-based rate tariffs include standard provisions so that the Commission can go beyond simply refunding profits and impose penalties on violators. Staff is aware that Congress is considering expanding the Commission's currently very limited civil penalty authority, and we strongly endorse expanded civil penalty authority that applies to jurisdictional companies that violate the Commission's orders and regulations, as a means to deter the types of conduct we have encountered in this investigation.**

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

I. INTRODUCTION

A. The Commencement of This Investigation

On February 13, 2002, the Commission issued an order entitled "Order Directing Staff Investigation."[5] In this Order, the Commission explained that, in the wake of the Enron's filing for bankruptcy on December 2, 2001, allegations were made that Enron Corporation, through its affiliates, used its market position to distort electric and natural gas markets in the West. These allegations include the claim that Enron's filing for bankruptcy had caused a substantial decline in spot prices, which, it was alleged, was evidence that Enron had manipulated prices prior to its bankruptcy.

In the February 13 Order, the Commission stated that it intended to gather information on whether any entity, including any Enron company, had 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, which resulted in potentially unjust and unreasonable rates in long-term power sales contracts.

To that end, the Commission in the February 13 Order directed 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.[[6]]

The Commission also stated that it:

> 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

[5]98 FERC ¶ 61,165 (2002) (February 13 Order).

[6]98 FERC at 61,614.

matters investigated, or any formal FPA section 206 or NGA [Natural Gas Act] section 5 proceedings initiated on our own motion.[7]

B. The Contents of, and the Reasons for, This Initial Report

In this report, the Staff investigation team in Docket No. PA02-2-000 recommends that the Commission initiate company-specific separate proceedings, in which specific instances of possible misconduct by public utilities can be further investigated and appropriate remedies imposed. These companies are three Enron affiliates (Portland, Enron Power Marketing, Inc., and Enron Capital and Trade Resources Corporation), El Paso Electric, and Avista. Staff has, at this point in time, gathered and analyzed evidence that is sufficient to recommend that the Commission initiate separate proceedings against these companies. The specific instances of possible misconduct include violations of the companies' codes of conduct and the Commission's standards of conduct; failures to make appropriate filings under sections 203 and 205 of the FPA; violations of the Commission's open access transmission requirements; and violations of minimum operating reserve requirements. Staff also presents its recommendations on generic reevaluations of the simultaneous offer rule that disciplines affiliate transactions to ensure that it is effective and verifiable.

In addition, Staff presents its initial findings and recommendations on the use of published natural gas prices for California delivery points in the California refund proceeding in Docket Nos. EL00-95-045 and EL00-98-042. Staff's findings and recommendations on this issue are being presented at this time, on an accelerated schedule in advance of the remainder of Staff's findings and recommendations, for three principal reasons.

First, a change in the fuel component in the refund formula used in the California refund proceeding will have a large dollar impact on customers.

Second, Staff wishes to have its findings and recommendations with respect to natural gas data in the California refund proceeding considered on a timely basis, so that, if the Commission were to adopt Staff's proposals, the Commission can issue an order to the administrative law judge to direct him to calculate refunds based on Staff's proposed alternative.

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[7] *Id.* (footnote omitted).

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Third, Staff's analysis of publicly-reported natural gas price data and our proposed alternative for the use of such data in the California refund proceeding are discrete subjects that can be readily separated from other issues that Staff is currently investigating. They are matters that can be presented for the Commission's consideration, and acted on as appropriate, pending Staff's continued investigation and ultimate completion of a final Staff report.

In brief, this initial report discusses generic characteristics in the price data reported in the energy industry trade press, as well as characteristics specific to California delivery point natural gas spot prices. We then discuss proposed alternatives for the refund calculation formula currently being used in the California refund proceeding and recommend that the Commission adopt one proposed substitute.

Finally, this report discusses the Enron trading strategies, as outlined in the formerly-confidential Enron memoranda, and the results of Staff's information requests to other market participants seeking admissions or denials as to whether those other market participants also engaged in those, or similar, trading strategies.

Due to the breadth of the investigation, Staff's work is continuing. We have not described all of our lines of inquiry, and many details of our investigation, because such descriptions may damage ongoing criminal and civil investigations by the Department of Justice, the CFTC, or the SEC. In addition, Staff is concerned that prematurely revealing details about allegations we have received may adversely affect the due process rights of the persons involved.

The complexity of the issues confronting Staff and the agencies cooperating with the Commission is such that more time would be required to fully understand Enron's and other market participants' activities in the energy markets. For example, we spent a considerable amount of time analyzing Enron's massive information technology (IT) systems that were used to harness information and use such information for Enron's advantage. In short, the IT systems were functionally equivalent to the IT systems of a national trading exchange, *e.g.*, a stock exchange, coupled with the credit and risk systems of a large international bank, and linked to a large telecom company. The IT systems were designed to keep transactional data, such as a telecom IT system must do with telephone service customers such as customer service, billing, scheduling, and provisioning, but also link it to a sophisticated, on-line trading platform, and calculate the credit and risk exposure of each transaction. Because Enron traded 1700 different products on-line around the world, the trading had to be linked together in a secure manner.

Although Staff has focused its energies on relevant data, the size of the task is enormous. For example, as described herein, Staff is now reviewing approximately 1.8 terabytes (TB) of data, which is equivalent to the amount of data produced by a large telecom company. In addition, because the data had to be easily accessible to Enron employees, we are also reviewing nearly 1,000 spreadsheets that were populated with data from the IT systems. The spreadsheets were approximately 40 megabytes (MB) each and dozens were created daily.

C. The Current Status of the Investigation

Staff, with the assistance of its outside consultants, is conducting a comprehensive investigation of a variety of factors and behaviors that may have influenced electric and natural gas prices in the West during 2000-2001. This is a time- and resource-intensive investigation which involves extensive data gathering and data analysis. In response to data requests, document productions, interviews and depositions, Staff has collected hundreds of boxes of printed material and in excess of 1,200 GB of electronic data. This includes hundreds of thousands of e-mail messages and attachments, and 61,908 electronic files of various types, including word processing document and spreadsheets. We are expecting to receive more material during the course of this investigation.

As articulated in the February 13 Order, the Commission's directive to Staff was to investigate whether any entity had manipulated short-term prices in electric energy or natural gas markets in the West, or otherwise exercised undue influence over wholesale prices. In this section, we highlight the major areas of Staff's investigative activities during the course of this fact-finding proceeding and the subject areas that will be covered in the final report to be presented when the investigation is completed. We emphasize that this section does not contain a complete history of Staff's investigation, but rather focuses on the major activities.

One of Staff's first actions in this investigation was to gather information necessary for formulating and validating preliminary theories of market manipulation, including data on sale and purchases (volumes, prices, delivery points, counter-parties, etc.) of wholesale electric markets in the Western United States. This information will provide us with a more complete picture of the landscape of forward electricity sales in the West and is critical to understanding the behavior of wholesale markets in the West.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

To that end, Staff issued an information request answered by roughly 250 respondents.[8] The respondents included all segments of the industry: investor-owned utilities, municipalities, cooperatives, affiliated and non-affiliated power marketers, federal power marketing agencies, and independent power producers. As is to be expected, the quality of those answers (totaling over 525 MB of electronic data and approximately four boxes of printed material) varied widely, and Staff, with direct involvement of our consultants, designed a validation program for the data and contacted many respondents to ensure the completeness of their responses. Enron's response in particular was extremely deficient, and Staff was compelled to speak to and meet with Enron and its attorneys on several occasions to ensure compliance.

Staff currently is in the process of aggregating the sales data into a single database for all sales transactions. This is a key basis for our investigation that allows us to investigate the principal factors that may have influenced prices in the West and may have allowed some market participants to manipulate markets.

In addition to compiling this sales database, we have exported (that is, downloaded to our own file server) Enron's databases, where Enron accumulated data on its physical and financial transactions (both electric and natural gas), including Enron's cash positions, its risk management system, its VAR (value at risk), and its "stack manager" application (by which Enron traders controlled the posted prices on EOL).

A large portion of the Enron electronic data we have acquired is in the form of Oracle and Microsoft SQL Service relational databases. These databases are now hosted on a Commission-owned file server located in the secure Aspen Systems data center. Each database represents the material stored on a unique Enron database. The total size of all of the databases Staff has extracted (including backups and indices) is 1.8 TB. As a reference point, 1.8 TB of data is the equivalent of approximately 1.3 million floppy disks.

The name of each database, the information collected on it, and the approximate size is listed below:

[8]This information request, along with all other public discovery requests issued in Docket No. PA02-2-000, is available on the Commission's web page.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

- EOL: the on-line trading platform for a wide variety of commodities, including electricity and natural gas (120 GB);
- Sitara: the physical natural gas deal capture and tracking system (45 GB);
- Enpower: the physical electricity deal capture and tracking system (250 GB);
- TAGG/ERMS: the risk management system (300 GB);
- RisktRac: the global risk aggregation system (211 GB);
- CPR: the cash position reporting system (18 GB);
- CTR: the contracts tracking system (4 GB);
- GCC: the global common code (reference lists) system (1 GB);
- GCP: the global counter-party system (2.5 GB); and
- Unify Gas, Unify Power, and Unify Financial: the deal settlement systems (114 GB).

Staff has also made several site trips to various Enron offices, including its West Trading Desk in Portland, Oregon and its headquarters in Houston, Texas, to gain first-hand experience as to Enron's operations, including its trading platform.[9] Staff has requested and received transcripts of traders' telephone conversations with counter-parties, including their affiliates, and we are in the process of reviewing those transcripts.

In addition to the data intensive analytical investigation underway, Staff is also investigating traders and analysts from Enron and other companies through depositions and interviews. Staff has made multiple visits to Enron's offices in both Houston and Portland in order to perform interviews and search through documents necessary in deciding who to depose. Staff also identified summary data and information useful for the anticipated depositions and in support of the entire investigation. In approaching our

[9]Electricity products for the West were traded in Portland, while natural gas products were traded in Houston.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

depositions, we have used the following definition of manipulation as articulated in CFTC caselaw: (a) the entity must have the ability to influence market prices; (b) the entity specifically intended to do so; (c) artificial prices existed; and (d) the entity caused the artificial prices.

Beginning in May, Staff began deposing traders, analysts, and attorneys. CFTC Staff and Commission Staff cooperated in this process, which continues today. To date, Commission Staff and CFTC Staff have jointly interviewed or deposed more than 100 persons, including traders, IT system analysts, and attorneys. In addition, Staff is sharing information with, and otherwise coordinating with, other investigatory agencies, including the Department of Justice and the SEC.

Cooperation between Commission Staff and CFTC Staff is not limited to interviews and depositions. Commission Staff has provided, and continues to provide, CFTC Staff with all the IT resources necessary to analyze the EOL databases and also with expertise in the physical natural gas and electricity markets. This inter-agency cooperation will help to ensure that the investigation of Western electricity and natural gas markets is complete and coordinated.

On May 6, 2002, Enron's Washington, DC counsel produced three memoranda, two of which date from December 2000, that describe certain trading strategies employed by Enron's traders in the West. The memoranda also discuss the possible sanctions that the California Independent System Operator Corporation (Cal ISO) could apply if it were to discover that Enron was using such trading strategies. Enron's counsel informed us that Enron's Board of Directors had voted to disclose the documents and to waive all claims of privilege. These memoranda were partially responsive to previous data requests that had been issued in Docket No. PA02-2-000. The Commission made these documents publicly available on our web site within hours of our receipt of them.

In order to better understand the trading strategies discussed in the memoranda, which include, among other things, megawatt laundering and means by which Enron could receive congestion payments without actually acting to relieve any congestion, we issued that same day a follow-up data request to Enron. We requested that the company provide us with the names of the traders who were interviewed by the authors of the memoranda and whose trading strategies are the subject of the memoranda. We also requested the production of any comparable memoranda that discuss trading strategies for natural gas products (since the memoranda only discuss electricity trading strategies). Finally, the data request asked Enron to provide us with all correspondence related to the

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

subject matter of the memoranda. Enron continues to provide us with responses to that data request.

The Enron memoranda allege that traders from other companies were also employing several of the trading strategies discussed in the memoranda. In order to pursue this issue, we issued, on May 7, 2002, a notice to all sellers of wholesale electricity and/or ancillary services in the West, informing them that we would soon be sending them a data request seeking information about their use of the trading strategies discussed in the Enron memoranda, and directing them to preserve all documents related to such trading strategies.

On May 8, 2002, we issued a data request to over 130 sellers of wholesale electricity and/or ancillary services in the West during 2000-2001, with a due date of May 22, 2002. This data request contained a series of requests for admissions, in which an officer of each company was to admit or to deny, under oath, whether his or her company had engaged in specific activities described in the request. The specific activities were based on the trading strategies discussed in the Enron memoranda; in addition, there was a "catch-all" request for admission, asking the corporate officer to admit or deny under oath whether the company had engaged in any other trading strategies. The data request also sought production of all internal documents that relate to trading strategies that the company may have engaged in during the relevant time period, including correspondence between companies, reports, and opinion letters. We also requested information specifically with respect to any megawatt laundering transactions that any of these sellers might have engaged in with Enron.

This data request required that a senior officer of the company state, in an affidavit and under oath, that he or she conducted a thorough investigation of the company's trading activities in the West during 2000 and 2001 and that the information being provided in response to the data request is complete and accurate to the best of that person's knowledge and belief.

While Staff received over 835 MB of electronic data and numerous boxes of printed material in response to this data request,[10] we did not obtain full compliance. Therefore, on June 4, 2002, the Commission issued an order directing four companies –

[10]Staff provided Congressional staff with the responses to this data request, both public and non-public, in response to requests for document production.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Avista, El Paso Electric, Portland, and Williams Energy Marketing & Trading Company (Williams) – to show cause why their market-based rate authority should not be revoked.[11] The basis of the Show Cause Order was the companies' failure to provide Staff with complete and accurate responses to the May 8 data request. Staff has been in communication with all four of these companies and each has filed supplemental answers, which Staff is in the process of reviewing.[12] In response to the Show Cause Order, Williams invited Staff to investigate allegations that Williams had manipulated natural gas markets in the West. Staff issued an additional set of data requests to Williams in order to investigate those allegations, and Williams agreed to allow Staff to visit its offices and view and download data from its computers relevant to that investigation.

Staff issued another set of "admit or deny" data requests for electric and gas wash trades on May 21, 2002, and May 22, 2002, respectively. These data requests asked that a senior officer of the company admit or deny, in an affidavit and under oath, whether his or her company engaged in so-called "wash," "round trips," or "sell/buyback" trading for gas and electricity products. This trading was defined as involving the sale of natural gas or an electricity product to another company together with a simultaneous purchase of the same product at the same price and at the same location.

Only ten companies admitted to engaging in any of the trading strategies that were the focus of the May 8, 2002, "admit or deny" data request (several other companies gave answers other than "admit or deny"). The responses to this data request are discussed in detail later in this report. Four companies admitted to engaging in some form of electricity wash trading, while no company admitted to engaging in a form of gas wash trading, although eight companies gave answers other than "admit or deny."

D. The Contents of the Final Report

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[11]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Order to Show Cause Why Market-Based Rate Authority Should Not Be Revoked, 99 FERC ¶ 61,272 (2002) (Show Cause Order).

[12]After reviewing their supplemental answers, Staff has concluded that El Paso Electric and Williams have now complied with the Show Cause Order. Letters so stating were sent to El Paso Electric and Williams and are posted on the Commission's web page for this investigation.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Based on the information it has gathered during the course of its investigation, at this point in time, Staff's final report in this proceeding will include the following areas of inquiry. We emphasize that our investigation is ongoing, and other areas of inquiry may be added to the final report.

- An explanation of the operations of EOL, including analyses of its various databases and a discussion of the impact that EOL (or any of its affiliates that used EOL as a trading platform) might have had on prices in Western markets, including possible attempts to manipulate prices for natural gas or electric products in the West.
    - An analysis of the role EOL played in the markets for both the physical delivery of natural gas and electricity products, as well as in derivative (financial) products.
    - An explanation of the particular characteristics of EOL that distinguish it from other electronic trading platforms and what role those unique characteristics may have played in the alleged manipulation of energy prices by Enron and other market participants.
    - A discussion of Staff coordination with the CFTC and other agencies that are investigating EOL, as well as Staff's depositions and interviews with former employees of Enron and other individuals.
- An analysis of selective sales data from short-term, seasonal, and long-term forward contracts Staff collected from information requests. Staff will explain the results of our statistical analysis of such data, including our findings of how, and to what extent, forward prices directly correlate with spot energy prices.
- An analysis of wash trades in electricity and natural gas in the West during the two-year review period, including Staff's analysis of the responses to data requests about wash trades, and Staff's recommendations on the Commission's regulation of wash trades.
- A discussion of Staff's findings from its investigation into specific published allegations that Williams had attempted to manipulate natural gas markets in the West. As previously noted, Williams invited Staff to investigate these allegations, and agreed to allow Staff to visit its offices and download data from its computers.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

That investigation has, to date, included data requests, on-site visits, interviews or depositions of Williams employees, and review of exported Williams databases.

- An analysis of the interrelationship between physical and financial natural gas and electric products.

- Recommended standards and protocols for dealing with physical withholding on a prospective basis.

- Further analysis of the extent to which the Enron strategies had an effect on other products, such as long-term physical and financial contracts.

Staff emphasizes that our investigation is both ongoing and iterative; thus, additional areas of inquiry and recommendations not mentioned in this section of the initial report may be included in the final report.

II. BACKGROUND: CALIFORNIA RESTRUCTURING

A. Restructuring of California's Electricity Industry

In the mid-1990s, the electricity industry in California was restructured in accordance with California legislation (Assembly Bill 1890). The goal was a new market structure that would bring about a fundamental shift in the way electricity was bought and sold in California, promoting unbundled sales of electric energy by multiple sellers to retail distributors and end-users at market-based rates. The restructuring legislation called for the creation of an independent system operator (namely, the Cal ISO) to control the transmission grid and a power exchange which would facilitate the creation of a transparent, visible spot market for electricity.

In a series of orders issued during 1996 and 1997, the Commission approved the restructuring proposals, with modifications, and the Cal ISO and California Power Exchange Corporation (Cal PX) became public utilities regulated pursuant to the FPA. The three investor-owned utilities (IOUs) in California (Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (San Diego) transferred operational control of their respective transmission systems to the Cal ISO, and began purchasing all of the energy needed to serve their retail customers through spot markets (day-ahead or day-of markets administered by the Cal PX. The three public utilities were precluded by California from entering into long-term contracts and were required to make all their purchases (and sales) through the Cal PX's spot markets. Each utility's retail rates were frozen by California statute for a period until each had recovered certain stranded generation costs.[13]

Early market operations proceeded relatively smoothly, with average wholesale energy prices at levels below those previously experienced in a cost-based regulatory regime, averaging about $33/MWh for the first two years.[14] The Cal ISO experienced more problems with its ancillary services markets, with market design issues and bid insufficiencies leading to the imposition of a $750/MWh purchase price cap (that is, the

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[13]The public utilities were to recover their stranded costs from the difference between competitive wholesale and frozen retail rates.

[14]U.S. General Accounting Office, *Restructured Electricity Markets: California Market Design Enabled Exercise of Market Power* (June 2002), at page 7.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Cal ISO would reject offers to sell power to it at prices above this level). In May 2000, however, real-time prices in the Cal PX market reached the Cal ISO's $750 for the first time, and the Cal PX average price in its day-ahead market for the month topped $316/MWh. In June 2000, prices reached levels that exceeded by three or four times those seen at comparable demand conditions in prior years. Thus began what has been termed the California Energy Crisis.

B. The California Energy Crisis

In response to the high prices, the Cal ISO Governing Board reduced the Cal ISO purchase price cap from $750/MWh to $500/MWh effective July 1, 2000, and again to $250/MWh on August 7, 2000. Soon after, San Diego filed a complaint at the Commission requesting that the Commission impose a $250/MWh price cap for sales into all markets operated by the Cal PX and Cal ISO. The Commission denied this request in an order issued August 23, 2000, on the grounds that San Diego had not provided sufficient evidence to support an immediate seller's price cap.[15] However, in that order, the Commission instituted formal hearing proceedings to investigate the justness and reasonableness of the rates of public utility sellers into the Cal ISO and Cal PX markets, and also to investigate whether the tariffs, contracts and institutional structures of the Cal ISO and Cal 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.

The report from that investigation, issued November 1, 2000, identified three factors that contributed to high electricity prices during the summer of 2000. First, the Report found that 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 played a major role. Second, existing market rules exacerbated the situation by exposing the three public utilities to the volatility of the spot market without affording them the ability to mitigate the price volatility, thereby increasing the amount of demand and supply that appeared in the Cal ISO's real-time market. Third, the Staff Report noted evidence suggesting that sellers had the potential

[15]San Diego Gas & Electric Company, *et al.*, 92 FERC ¶ 61,172 at 61,606 (2000), *order on clarification and reh'g*, 97 FERC ¶ 61,275 (2001), *order on further reh'g*, 99 FERC ¶ 61,160 (2002).

to exercise market power, although there were insufficient data to make determinations about the exercise of market power by individual sellers.

The Commission issued an order on November 1, 2000 proposing measures to remedy the problems identified in the Staff Report.[16] 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 conditions."[17] 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."[18]

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 holding overall rates to levels approximating competitive market levels while inducing sufficient investment in capacity to ensure adequate service.[19] The order proposed, among other things, to eliminate the requirement that the public utilities must buy all of their requirements from and sell all of their resources into the Cal PX, and to replace the existing Cal PX and Cal ISO stakeholder boards with independent non-stakeholder boards. To ensure fair prices while various market reforms were being put in place, the order proposed temporary measures to mitigate prices, including modification of the Cal ISO's real-time market so that bids above $150/MWh could not set the market clearing

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[16] San Diego Gas & Electric Company, *et al.*, 93 FERC ¶ 61,121 (2000), *order on clarification and reh'g*, 97 FERC ¶ 61,275 (2001), *order on further reh'g*, 99 FERC ¶ 61,160 (2002) (November 1 Order).

[17] *Id.* at 61,349-50.

[18] *Id.* at 61,350.

[19] *Id.*

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

price that is paid to all bidders, and imposing certain reporting and monitoring requirements for bids above the $150/MWh breakpoint (dubbed a "soft price cap").[20]

The Cal ISO's reduction of its purchase price cap to $250/MWh resulted in its rejection of more and more bids. Beginning in mid-November, the Cal ISO began to experience emergency conditions in its control area caused by severe and persistent bid insufficiency, forcing it to serve increasingly large portions of its total load through its real-time market. Thus, on December 8, 2000, the Cal ISO submitted and the Commission accepted for filing a tariff amendment intended to relieve the situation. Notably, the existing $250/MWh purchase price cap on bids into the Cal ISO's real-time market was converted into a $250/MWh breakpoint, similar to the "soft price cap" described in the November 1 Order, so that offers to sell power at prices exceeding $250/MWh were not rejected (but also did not affect the market-clearing price paid to other generators) and the sellers were required to provide data showing that such prices were justified.

The Commission adopted many of the proposed remedies presented in the November 1 Order in an order issued December 15, 2000.[21] The December 15 Order focused on the need to reduce reliance on spot markets while balancing the need for incentives for sellers to sell into California and for investment in generation and transmission facilities, with the overall goal of alleviating the extreme high prices being borne by Californians. Key remedial measures that were adopted included: eliminating the requirement that the three California public utilities sell all of their generation into and buy all their energy needs from the Cal PX so as to end the over reliance on spot markets (which required termination of the Cal PX's wholesale rate schedules as of the

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[20]The Commission also identified longer-term structural reforms that needed to be addressed, including improved market monitoring and market mitigation strategies, submission of a congestion management redesign proposal, and demand response programs. 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.

[21]San Diego Gas & Electric Co., *et al.*, 93 FERC ¶ 61,294 (2000), *order on clarification and reh'g*, 97 FERC ¶ 61,275 (2001), *order on further reh'g,* 99 FERC ¶ 61,160 (2002) (December 15 Order).

close of the April 30, 2001 trading day)[22]; and establishing an interim modification of the single price auction as proposed in the November 1 Order and reporting requirements for transactions and/or bids over $150/MWh.

Also during December 2000, several ratings agencies lowered or put on watch debt ratings for Edison and PG&E and their corporate parents. The public utilities were facing increasing liquidity pressures since they could pass on to retail customers only a small portion of their wholesale purchased power costs when they were paying an average of $250/MWh for power in the spot market. As a result, the public utilities began having difficulty finding sellers willing to risk sales to them.[23] Edison explained in a late December filing that, unless the California Commission ended its retail rate freeze, allowing recovery of wholesale costs in retail rates, and this Commission ordered a return to cost-based rates, it would not be able to meet its January financial obligations. Edison's and PG&E's bonds reached junk status in January 2001.

In early 2001, the Commission acted to address the sinking credit ratings of PG&E and Edison. The Commission allowed the companies to continue to schedule transactions from generation they owned to serve their own load, despite their failure to meet the creditworthiness standards of the Cal ISO and Cal PX tariffs. However, the Commission would only permit the companies to schedule transactions with others if they obtained financial backing from creditworthy counter-parties.

In January 2001, the California Department of Water Resources (DWR) began purchasing power for sale to Edison and PG&E and serving as a creditworthy counter party with the backing of California state appropriations. The Commission believed that ensuring payment for services by a creditworthy counter party would increase the supply in the Cal ISO's energy imbalance market and reduce the need for emergency dispatch instructions.[24]

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[22]The Cal PX closed its core markets on January 31, 2001. On March 9, 2001, it filed for protection under Chapter 11 of the Bankruptcy Code.

[23]To prevent possible widespread outages, the Secretary of Energy began issuing orders pursuant to FPA section 202(c) requiring electric utilities to offer their resources to the Cal ISO during system emergencies.

[24]PG&E filed for protection under Chapter 11 of the Bankruptcy Code on April 6,
(continued...)

C. Price Mitigation Measures

On April 26, 2001, the Commission issued a prospective mitigation and monitoring plan for wholesale sales through the organized real-time markets operated by the Cal ISO,[25] and established an inquiry into whether a price mitigation plan should be implemented throughout the Western Electricity Coordinating Council (WECC).[26] Elements of the plan included:

- Enhancing the Cal ISO's ability to coordinate and control planned outages during all hours.
- Requiring sellers who own or control generation in California that voluntarily make sales through the Cal ISO's markets or use the Cal ISO's interstate transmission grid, to offer all their available power (with the exception of hydroelectric power) in real time during all hours ("must-offer requirement").
- Establishing conditions, including refund liability, on public utility sellers' market-based rate authority, in order to prevent anti-competitive bidding behavior in the real-time market during all hours.
- Establishing a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the Cal ISO's real-time market during a reserve deficiency (when operating reserves fall below seven percent). Under this mechanism, the Commission established a formula (based on gas-fired generation) to establish the market-clearing price when mitigation applies. Higher bids by sellers other than marketers were permitted if they could be justified.

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[24](...continued)
2001.

[25]San Diego Gas & Electric Co., *et al.*, 95 FERC ¶ 61,115 (2001), *order on reh'g*, 95 FERC ¶ 61,418 (2001), *order on clarification and reh'g*, 97 FERC ¶ 61,275 (2001), order on further reh'g, 99 FERC ¶ 61,160 (2002).

[26]The WECC was previously named the Western Systems Coordinating Council. References throughout this Report to the WECC are intended to refer only to the United States portion of the WECC.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

In an order issued on June 19, 2001, the Commission modified and expanded the mitigation plan in significant aspects, including adopting a modified plan to mitigate spot market transactions throughout the WECC.[27] Additional elements of the mitigation plan, to be in effect through September 30, 2002, include:

- Beginning as of June 20, 2001, applying the Cal ISO's mitigated clearing price as a maximum price for spot market sales outside the Cal ISO's single price auctions (in bilateral sales in California and the rest of the WECC), with sellers outside the single price auction receiving the prices they negotiate up to this maximum price.

- Using eighty-five percent of the highest Cal ISO hourly mitigated clearing price established during the hours of the reserve deficiency alert for subsequent non-reserve deficiency hours.

- Expanding the must-offer requirement West-wide, thus requiring all utilities in the WECC outside of California to offer in the spot market of their choosing any non-hydroelectric resource to the extent the output was not already committed.

The Commission issued two subsequent orders revising how the mitigated price is to be calculated. The first order modified the price mitigation methodology for the winter 2001 season based on a certain percentage increase in natural gas prices.[28] The second order established a hard price cap at the previously existing maximum clearing price ($91.87/MWh), ending the Cal ISO's ability to trigger recalculation through its procurement activities.[29] This hard cap will be in place for the period July 12, 2002

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[27]San Diego Gas & Electric Co., *et al.*, 95 FERC ¶ 61,418 (2001), *order on clarificationn and reh'g*, 97 FERC ¶ 61,275 (2001), *order on further reh'g*, 99 FERC ¶ 61,160 (2002) (June 19 Order).

[28]Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council, 97 FERC ¶ 61,294 (2001), *reh'g denied*, 99 FERC ¶ 61,161 (2002), *reh'g pending*. This methodology was never triggered, as gas prices did not rise sufficiently during the winter of 2001.

[29]San Diego Gas & Electric Co., *et al.*, 100 FERC ¶ 61,050 (2002).

through September 30, 2002, when Phase I of the ISO's market redesign will be implemented.[30]

Regarding transactions occurring before the prospective price mitigation took effect, the Commission issued an order on July 25, 2001 establishing the scope of, and the methodology for, calculating refunds related to transactions in the spot markets operated by the Cal ISO and the Cal PX. The refund methodology adopted most of the criteria of the prospective price mitigation plan, modified as to be appropriate for a past, rather than a future, period. The Commission also established hearing procedures to develop a factual record from which to calculate the refunds. The hearing will determine the mitigated price during each hour of the refund period, the amount of refunds owed by each supplier, and any amounts that had not been paid to suppliers by the Cal ISO, the Cal PX, and other purchasers. These proceedings have been ongoing, and a hearing is currently scheduled to begin on August 19, 2002.

[30] *See* California Independent System Operator Corp., 100 FERC ¶ 61,060 (2002). The Commission approved the following price mitigation elements to become effective October 1, 2002: (1) continuation of the existing must-offer requirement; (2) a bid cap limiting the maximum bid into WECC spot markets to $250/MWh; (3) automatic mitigation procedures (AMP) similar to those in New York whereby prices are mitigated if bidding behavior is deemed inconsistent with competitive markets and if acceptance of the bids would have a substantial impact on market prices; and (4) a modified AMP to address local market power.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

III. RECOMMENDATIONS FOR COMPANY-SPECIFIC SEPARATE PROCEEDINGS AND GENERIC REEVALUATIONS

In this section of the report, Staff presents its review of some of the evidence it has gathered and analyzed during the course of its investigation in Docket No. PA02-2-000. Staff's analysis of that evidence leads it to recommend to the Commission that separate proceedings be initiated to further investigate specific instances of possible misconduct by specific companies. Staff also recommends that the Commission reevaluate the simultaneous offer rule that it uses to discipline affiliate transactions to ensure that it is effective and verifiable.

A. El Paso Electric and Enron

In the course of its investigation, Staff has uncovered preliminary evidence that El Paso Electric and Enron may have engaged in actions that adversely affected prices; may have violated open access transmission requirements; may have failed to file jurisdictional rate schedules or disposed of (through ceding control of) jurisdictional assets without prior Commission approval; may have failed to timely notify the Commission of material changes to the circumstances under which they were granted market-based rate authority; and may have deliberately violated minimum operating reserve requirements.

In addition, Staff has uncovered preliminary evidence that El Paso Electric's management may have failed to properly supervise Enron's use of El Paso Electric's assets pursuant to unfiled agreements, and may have allowed El Paso Electric's assets to be used improperly. For example, Staff has evidence that Enron's commitment of El Paso Electric energy may have resulted in a pattern of violations of minimum operating reserve requirements, as established by the regional reliability council; that El Paso Electric management may have knew of these actions; and that El Paso Electric may have failed to promptly stop such actions. The nature of the relationship between El Paso Electric and Enron is of particular concern to Staff, in part because there is evidence that the companies themselves were worried that, because of their relationship, they were no longer "competitors."

Staff believes that the quantum and quality of this evidence warrants Staff recommending that the Commission institute further proceedings, apart from Docket No.

PA02-2-000, in which El Paso Electric and Enron[31] may respond to these allegations, further evidence may be submitted, and remedies (including possibly refunds and/or revocation of El Paso Electric's and/or Enron's market-based rate authority[32]) may be imposed, as appropriate, for any findings of improper conduct.

To ensure fairness to the companies, as well as to avoid compromising the cases against them, Staff believes that specific details of evidence against El Paso Electric and Enron should be discussed only in orders voted out by the Commission, rather than in a report to Congress, to which Enron and El Paso Electric cannot respond on the record. However, some of the material that illustrates Staff's concerns is already public information.[33] For example, as the Commission noted in the Show Cause Order, El Paso Electric has admitted to substantial joint dealings with Enron, and concedes that Enron personnel manned its trading desk 75 percent of the time during 2000-2001. But, in its affidavit submitted in response to the May 8, 2002, data request, El Paso Electric stated that it knew nothing of Enron's dealings on its behalf.

This is directly contradicted by, for example, a letter from Enron to three senior executives at El Paso Electric, including two executive vice presidents. In this letter, Enron discusses how the two companies had taken advantage of the unseasonably hot weather and unit outages that occurred in the West during a single month in the summer of 2000. This led, Enron states, to El Paso Electric receiving revenues in excess of $7 million from that month's joint dealings between El Paso Electric and Enron. Two days later, El Paso Electric senior executives wrote back to their counterparts at Enron, stating that the results achieved by the two companies were a "great illustration of what is possible when teamwork, knowledge, initiative and accountability all come together."

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[31]According to documents in Staff's possession, El Paso Electric's dealings were with at least two Enron affiliates, Enron Power Marketing, Inc. (EPMI) and its parent, Enron Capital and Trade Resources Corp.

[32]*See* El Paso Electric Company, 87 FERC ¶ 61,219 (1999) (granting El Paso Electric market-based rate authority); Enron Power Marketing, Inc., 65 FERC ¶ 61,305 (1993) (granting EPMI market-based rate authority).

[33]In addition, Staff notes that the El Paso Electric response to the Show Cause Order is among the material, both public and non-public, that the Commission has provided to Congressional staff in response to requests for document productions.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

The El Paso Electric senior executives further stated that they "believe our relationship with Enron has enhanced these characteristics."

Staff believes that a separate proceeding to investigate the nature and extent of the relationship between Enron and El Paso Electric, and to explore the clear contradiction between El Paso Electric's statement, under oath and in an affidavit, that it knew nothing of Enron's dealings on its behalf and this correspondence, is needed. It appears that, at the very least, El Paso Electric was complacent in not properly monitoring Enron's activities on El Paso Electric's behalf. Indeed, Staff has evidence that market participants complained that, when they called El Paso Electric's trading desk, they were uncertain whether they were actually dealing with El Paso Electric or with Enron. In any event, even if El Paso Electric was not aware of Enron's activities, it was the responsibility of El Paso Electric's management to ensure that it fully monitored all of Enron's activities on its behalf.

Information in Staff's possession indicates that the joint dealings between Enron and El Paso Electric in fact may have adversely affected prices and markets in the West. For example, with respect to the correspondence about monthly revenues for summer 2000, discussed above, Staff cannot readily account for such a high level of revenues over a single one-month period, even given unseasonable weather and unscheduled outages. Certainly, the two companies themselves thought that this amount of monthly income was extraordinary, and thereby worthy of comment and mutual congratulations. This is, in and of itself, not evidence of improper conduct, but does indicate that further investigation is needed. In addition, Enron and El Paso Electric's merchant function may have received preferential access to El Paso Electric's transmission system in violation of the Commission's open access transmission requirements, in order to engage in highly profitable sale/buyback transactions with Mexico. This, too, should be investigated.

Until it obtained the relevant documents through the discovery process in Docket No. PA02-2-000, Staff had no means of knowing that Enron was acting on El Paso Electric's behalf, including performing management services for it and controlling some of El Paso Electric's assets pursuant to a contractual arrangement. As a public utility with market-based rate authority, El Paso Electric is obligated under the terms of the Commission order granting it such authority, to notify the Commission of material changes of circumstances or include the information in its updated market power analysis. Staff has in its possession a document which indicates that El Paso Electric's management was, as early as 1997, concerned about the precise nature of the relationship between the two companies -- including whether Enron was accurately reporting the price

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

at which it sold El Paso Electric's power – but El Paso Electric apparently did not sever its relationship with Enron until the time of the latter's bankruptcy. Separate proceedings to investigate this situation are clearly needed.

Further, Staff believes that, in light of El Paso Electric's possibly ceding control of its assets to Enron in a contractual relationship, any separate investigation should determine if El Paso Electric and Enron should have made any filings pursuant to sections 203 and/or 205 of the FPA. To the extent that the result of that proceeding is a finding that El Paso Electric or Enron improperly failed to file jurisdictional rate schedules or contacts, or receive prior Commission approval for a disposition of jurisdictional facilities, appropriate remedies may be in order. Similarly, to the extent that El Paso Electric or Enron violated the terms and conditions of the Commission orders granting each of them market-based rate authority, revocation of such market-based rate authority may be appropriate.

It is entirely possible that other companies may have engaged in similar violations, which may have had larger financial consequences. These types of arrangements or service agreements may have been a key factor in the exercise of market power. For competition to be effective, all of the Commission's rules and regulations, including its standards of conduct and codes of conduct, must be scrupulously followed and enforced. By initiating this investigation, the Commission will put all companies on notice that violations will not be tolerated.

B. Portland and Enron

Staff also recommends that the Commission initiate a separate proceeding to investigate possible violations by Portland and Enron (specifically, EPMI) of their codes of conduct[34] and the Commission's standards of conduct, and the imposition of any appropriate remedies. Codes of conduct, as supplemented by the company's market-based rate tariffs, govern, among other things, a power marketer's relationship with its affiliates, including limitations and conditions on market-based transactions with its affiliate with captive customers and the pricing of sales of non-power goods and services.

[34]As a power marketer, EPMI is required to have a code of conduct on file in conjunction with its market-based rate authority. In addition, Portland, which is a traditional public utility with captive customers, has filed codes of conduct with the Commission.

For example, specific Commission approval would be needed for Enron to sell power at market-based rates to Portland, and any sharing of information between Portland and Enron must be simultaneously disclosed to the public. The Commission reviews and accepts codes of conduct and market-based rate tariffs as part of the power marketer's application for market-based rate authority.

Standards of conduct are contained in the Commission's regulations[35] and generally require that the employees of a transmission provider engaged in transmission system operations function independently of those employees engaged in the wholesale merchant function (and also of employees engaged in the wholesale merchant function of any of the transmission provider's affiliates). For example, the standards of conduct require that employees of Portland's transmission function act independently of employees of Portland's merchant function and of employees of EPMI's merchant function.

As was the case with El Paso Electric and Enron, Staff will not fully disclose the precise nature of the evidence it has in hand at this time in the context of a Congressional report. However, Staff has preliminary evidence, taken from transcripts of recorded telephone conversations, indicating that Portland and Enron knowingly engaged in transactions that may constitute violations of the standards of conduct and/or the companies' codes of conduct.

For example, in the transcripts, an Enron employee explains to a Portland employee that they cannot buy and sell energy directly, but must use a non-affiliated utility as a middle man. There is also evidence that Portland employees knew that the requests they were receiving from their affiliates were improper. For example, when two Portland transmission function employees are discussing an Enron request for such a three-party arrangement, one reports that a third employee thinks the arrangement is not legal. In another instance, a Portland transmission function describes the three-party arrangement as "a scam."

Staff believes that even this limited information supports further investigation in a separate proceeding. Moreover, these quotations were taken from transcripts of conversations recorded during a single month during the two-year period under review in Docket No. PA02-2-000. It is highly doubtful that this kind of conduct occurred only in

[35] 18 C.F.R. § 37.4 (2002).

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

that single month. A separate investigation would allow discovery of instances of questionable transactions not only during, but also before and after the two-year review period for this proceeding.

As these quotations discussed above make clear, Enron and Portland often required the cooperation – either knowing or unwitting – of third parties for their inter-affiliate transactions. At this point in time, Staff is making no recommendations with respect to those third parties, pending the completion of our analysis of the roles such third parties played.

C. Avista, Portland, and Enron

In its answer to Staff's initial request of May 8, 2002, Avista did not admit to involvement in any of the Enron trading strategies. In response to the Show Cause Order, Avista now admits that it facilitated the transactions previously identified by Portland in a middleman capacity. In fact, Avista states that it routinely acted as a middleman between affiliates such as Enron and Portland in order to allow transactions to proceed which affiliates would be forbidden to undertake directly. Avista states that it did so as an accommodation to maintain good relations with common trading counter parties. In fact, Avista states that: "the Avista Utilities traders believed that they were performing a common industry function as an intermediary between two parties who are restricted in dealings to facilitate real trades and a robust and liquid market." Avista fully admits now that its own traders "did have questions about the transactions."

While admitting that this was part of its standard business practice (that is, to facilitate transactions which were prohibited among affiliates directly), Avista made no attempt to go beyond the discrete transactions previously revealed by Portland. Avista argues that, because its tapes cannot be reviewed by electronic search methods, "there was no way for Avista Utilities to conduct any kind of meaningful review of all, or even a portion, of the telephone conversations in its possession and no way to focus such a review."

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Avista concludes that the Commission cannot revoke its market-based rates[36] without an investigation under Section 206 of the FPA, and that the Commission cannot impose any form of sanction for Avista's failure to respond because the data request violated the Paperwork Reduction Act.

Avista's claim that it was "used" unwittingly by Enron is not reconcilable with its acknowledged practice of acting as an affiliate go-between as a routine matter. Nor is its claim that, without electronic search methods, it is incapable of coming forth with a thorough analysis of its own activities acceptable. This response is in sharp contract to many other entities that made a considerable effort to provide full and complete responses to the data requests. In summary, Staff finds that Avista's response is less than forthcoming. Staff recommends that the Commission institute further proceedings, apart from Docket No. PA02-2-000, to investigate Avista's activities over the 2000-2001 period. This investigation should address the extent to which Avista engaged in or facilitated the Enron trading strategies and the circumvention of prohibitions on affiliate sales, including appropriate remedies such as refunds and revocation of market-based rates.

D. Generic Reevaluations

In addition to Staff recommending further proceedings for individual companies, Staff also recommends that the Commission generically reevaluate the conditions it currently imposes on market-based transactions between affiliates. For example, the Commission currently allows a public utility with captive ratepayers to sell to an affiliated power marketer, if the product being sold is simultaneously offered to non-affiliated buyers at the same price and same location. Such transactions are not subject to prior Commission review.

This simultaneous offer requirement is intended to prevent a sale between affiliates from being priced too low, resulting in the public utility's ratepayers subsidizing the transaction. The information that Portland provided to Staff demonstrates that the current Commission requirements are not being followed and are not effective for short-time transactions. The information indicates that electronic postings on Internet to sell

[36] Avista Utilities, an operating division of Avista Corporation, and Avista Energy, Inc. both are authorized to sell power at market-based rates. 76 FERC ¶ 61,255 (1996) and 77 FERC ¶ 61,233 (1997).

products are not timely or accurate and, in any event, are difficult for other parties to monitor. Due to the short-term nature of many affiliate transactions, there is insufficient time for non-affiliates to react to offers to sell at the same price as the product is being sold to an affiliate. In these circumstances, pricing discipline is lost.

Moreover, Avista states that it routinely acts as a middle-man between affiliates in order to allow transactions to proceed which the Commission would otherwise prohibit if undertaken directly. Therefore, this generic reevaluation should include to what extent middle-men such as Avista should have an affirmative obligation to obtain certification by the affiliates in question that their transaction complies with the Commission's affiliate rules. Finally, Staff recommends that the Commission consider imposing standardized information requirements so that transaction information can be electronically searched in an efficient manner, so that the Commission, or other market monitors, can easily confirm that rules are being followed.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

IV. ANALYSIS OF PUBLISHED PRICE DATA FOR NATURAL GAS AND ELECTRICITY, INCLUDING CALIFORNIA DELIVERY POINT PRICES USED IN THE CALIFORNIA REFUND PROCEEDING

A. Introduction: Background and Summary of Conclusions

In this section, Staff discusses its analysis of electricity and natural gas prices published by a variety of trade publications and the use of a subset of those published prices (spot prices at California delivery points) to calculate the mitigated market-clearing price (MMCP), and resultant refunds, in the ongoing California refund proceeding in Docket Nos. EL00-95-045 and EL00-98-042.[37]

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[37]The California refund proceeding is currently pending before an administrative law judge and was initiated by the Commission in an order dated July 25, 2001. As explained in more detail in the next section, the California refund proceeding employs a formula to calculate the MMCP that relies on an average of spot market prices published in the following multiple sources: *Gas Daily*, NGI's *Daily Gas Price Index* and Inside FERC's *Gas Market Report*. However, because *Daily Gas Price Index* and *Gas Market Report* did not have a listing for Southern California Gas Large Packages during the refund period, the *Gas Daily* reported price is to be used for calculation of the southern gas price during the refund period. The last published gas prices should be used in calculating the refund price for the days that *Gas Daily* is not published (weekends and holidays).

In addition, the Commission initiated prospective mitigation in a series of orders issued in 2001. San Diego Gas & Electric Co., *et al.*, 95 FERC ¶ 61,115 (April 26 Order), *order on reh'g*, 95 FERC ¶ 61,418 (2001) (June 19 Order), *order on clarification and reh'g*, 97 FERC ¶ 61,275 (2001) (December 19 Order). Prospective mitigation employs a formula that relies on monthly forward prices taken from the bid-week data published in *Natural Gas Week*. From June 19, 2001, until July 8, 2002, the mitigation cap ranged between \$92/MWh and \$108/MWh. On July 9, 2002 the Cal ISO recalculated the cap to \$57.14/MWh, and, on July 10, 2002, again reset it to \$55.26/MWh. Then, on July 11, 2002, the Commission issued an order which established a hard price cap of \$91.87/MWh until the end of the period during which prospective mitigation would be in effect (that is, through September 30, 2002). San Diego Gas & Electric Co., *et al.*, 100 FERC ¶ 61,050 (July 11, 2002). On July 17, 2002,

(continued...)

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

A variety of private, commercial companies report electricity and natural gas spot and forward contracts market prices[38] and, in some cases, volumes. These include Platts, Bloomberg, Natural Gas Intelligence (NGI), and Energy Intelligence Group.[39] (We refer to these entities, collectively, as the reporting firms.) This section of the report discusses: (1) Staff's ongoing analysis of the price data published by the reporting firms; (2) the incentives for market participants to manipulate published price data; (3) the influence of electronic trading platforms, specifically EOL on published price data; (4) the effect of wash trades[40] on published price data; and (5) issues with respect to price data specific to California, which make the published price data unreliable and therefore inappropriate for use in calculating the mitigated market-clearing price (MMCP) (and resultant refunds) in the California refund proceeding.

The California refund proceeding employs a rate formula for calculating the MMCP (and resulting refunds) that relies on published natural gas spot prices in California or at the California border (California delivery points). Subsequent to the Commission's orders directing the use of these published price data, the Commission established this investigation, which gave Staff a forum in which to conduct discovery of

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[37](...continued)
the Commission issued an order that established a West-wide price cap of $250/MWh, effective as of October 1, 2002. California Independent System Operator Corporation, 100 FERC ¶ 61,060 (2002).

[38]A forward contract is a supply contract between a buyer and a seller, in which the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of a commodity on a specified future date. Payment in full is due at the time of, or following delivery. A forward contract refers to non-exchange trading of commodities. The price in a forward contract may be agreed upon in advance, or there may be agreement that the price will be determined at the time of delivery.

[39]In addition, NYMEX, which is an organized exchange regulated by the CFTC, reports some prices. See Chapter V for a further discussion of NYMEX prices and, more specifically, the relation between the NYNEX natural gas futures prices and the Henry Hub natural gas spot prices reported by the reporting firms.

[40]Wash trades are transactions that give the appearance of sales and purchases, but which are initiated without the intent to make a bona fide transaction and which generally do not result in any actual change in ownership or the trader's market position.

the reporting firms, all of which are non-jurisdictional entities.[41] Because of the characteristics Staff has discovered in the published price data, Staff recommends the use of a substitute input for the cost of natural gas in the rate formula for the refund proceeding, as is discussed below.

In brief, Staff has discovered the following major problems with published price data, including specific issues with respect to California delivery point spot prices:

- the Commission cannot independently validate the reporting firms' price data, and undetected errors may exist due to a lack of formal verification procedures;

- there are incentives for market participants to manipulate prices reported to the reporting firms, including incentives specific to California due to its regulatory structure;

- wash trading may have an adverse effect on reported prices data; and

- EOL was a significant source of price discovery and formation, and was potentially susceptible to manipulation by market participants.

Accordingly, Staff concludes that published California delivery point natural gas spot prices are not sufficiently reliable to be used in the California refund proceeding for purposes of calculating the MMCP and resultant refunds. There is limited internal verification and no external validation auditing by the Commission. Thus, the Commission cannot rule out the possibility that market participants deliberately report inaccurate prices to the reporting firms in order to manipulate the reported prices data. Wash trades and EOL's former dominance as a means of price discovery also may have adversely affected the reliability of published price data.

In the next chapter, Staff notes that there may be a number of possible alternatives and discusses two possible substitutes for that data. In brief, Staff recommends that the MMCP be calculated using producing basin spot prices plus transportation costs. Specifically, the MMCP for the Refund Period should be calculated using producing area prices from *Gas Daily*, plus an allowance for interstate natural gas pipeline transportation and local distribution company charges. For southern California, the average of the

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[41] *See* 16 U.S.C. § 825f (1994).

reported San Juan and Permian prices should be used. For northern California, the West Coast (Alberta) price should be used.[42] Spot prices at producing areas can be independently validated by correlation analysis to Henry Hub prices.

Because natural gas at these producing areas is actually delivered to California, Staff believes that this alternative is superior to the other alternative which Staff considered, the price at Henry Hub. While Henry Hub is the most liquid natural gas market in the country, Henry Hub natural gas is not actually delivered to California. Either alternative is, however, superior (because of their liquidity) to the prices currently being used for the California refund proceeding, and either alternative is acceptable, given that prices at Henry Hub and at the producing areas highly correlate with each other. In contrast, the spot prices currently being used for the California refund proceeding do not correlate well with Henry Hub or other producing area prices.

Notwithstanding the variable quality of the information the reporting firms publish, the natural gas and electricity industries have a history of relying on published price data. For example, widely-cited studies of the effect of Enron's bankruptcy on forward electricity prices have used price data published by these reporting firms. In particular, on January 29, 2002, Dr. Robert McCullough, in testimony before the United States Senate Energy and Natural Resources Committee, alleged that forward electricity prices at the Mid-Columbia trading point fell by approximately 30 percent after Enron declared bankruptcy. The data he relied on for his study were from the Platts publication *Energy Trader.* (We discuss below Staff's ongoing analysis of the issues raised by Dr. McCullough.)

More generally, the natural gas and electricity industries rely on the prices published by the reporting firms as the actual forward prices for contract settlements, and many contracts are indexed to the published prices. In theory, this would give the sources the reporting firms rely on a significant economic incentive to attempt to manipulate reported prices.

Responses from information requests sent to the reporting firms confirm that the published prices may be susceptible to manipulation because of this economic incentive.

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[42]To the extent that the California delivery point spot price data discussed in this report are used in other rate application proceedings before the Commission, the Commission should evaluate the appropriateness of continuing such uses.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

To illustrate, the forward electricity prices published by the reporting firms are based on transactions reported by traders. The reporting firms contact traders who, they believe, are reliable, but the firms conduct varying degrees of formal validation of the responses. In fact, there appears to be have been a strong circularity in information sources. For example, EOL was a significant source of price discovery for traders who, in turn, were sources for the reporting firms. While the reporting firms may have checked prices with numerous traders, the traders themselves appear to have been getting their information from the same source (EOL) and validating that same information with one another. Enron traders, in turn, used the published prices as a basis for posting prices on EOL. This circularity and the lack of any external validation almost guarantee that errors would not be discovered and eliminated, and create an environment that facilitates, rather than discourages, manipulation and collusion.

In addition, contracts in the forward market (unlike contracts in the futures market[43]) are generally not standardized as to delivery dates, delivery locations, quantities, and prices. Since the reporting firms typically do not disclose the means by which they report these non-standard contracts, the reliability of the data is unknown.

Staff believes that, once the industry understands that the price data it has relied on previously share these characteristics, existing or new firms will rise to the challenge of producing more statistically-sound methods, and will be able to demonstrate a degree of statistical validity to their published price data. There is some early indication that existing firms are willing to respond to this opportunity. For example, on July 1, 2002, Platts published an Editor's Note in *Power Markets Week* announcing its intention to revise its reporting methodology in order to improve the quality of information it receives from market participants. The Editor's Note stated:

> Platts is in the process of refining its U.S. electricity indexes and assessments in order to provide the power market, financial institutions and the regulatory community with an improved tool for risk management and price discovery. As part of that process, Platts will be adjusting its price

[43]A futures contract is an agreement to purchase or to sell a commodity for delivery in the future: (1) at a price that is determined at initiation of the contract; (2) which obligates each party to the contract to fulfill the contract at a specified price; (3) which is used to assume or shift price risk; and (4) which may be satisfied by delivery or offset.

assessment methodology to put an even greater premium on verifiable, higher-quality price data.[[44]]

While this is clearly a step in the right direction, price data must still be subject to independent validation by the Commission before being used in a rate-setting proceeding.

[44]Platts *Power Markets Week*, July 1, 2002, Editor's Note: Important Notice: Proposed Refinements to Platts' Power Market Methodology.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

B. An Illustration of Varying Quality in Published Price Data: Staff's Attempts To Verify Dr. McCullough's Testimony on the Effect of Enron's Bankruptcy

The varying quality of reported price data can easily be demonstrated. On January 29, 2002, Dr. Robert McCullough testified before the United States Senate Energy and Natural Resources Committee. He stated that forward electricity prices at Mid-Columbia fell by approximately 30 percent after the announcement of Enron's filing for bankruptcy. The implication of Dr. McCullough's testimony was that Enron had manipulated the market, causing prices to exceed market levels, and its bankruptcy then led to prices falling to considerably lower levels.

While Dr. McCullough claimed a 30 percent price drop, his own chart supported a smaller decline. On February 4, 2002, an article in Platts' *Power Markets Week,* stated that the price drop was, in fact, not as large as McCullough reported, but was only about nine percent:

> In alleging a 30% price drop when Enron filed bankruptcy Dec. 2, [McCullough] cited data published by Platts Energy Trader. But the data shows that Mid-Columbia on-peak forward prices actually dropped about 9%. The 2003 contract fell from $38.50/MWh to $35/MWh between Nov. 29 and Dec. 3. The 2004 contract came down from $39/MWh on Nov. 29 to $35.25/ MWh on Dec. 3.[[45]]

As part of its investigation into allegations that Enron had manipulated the market, Staff reviewed the forward price data for the time period around Enron's bankruptcy (December 2001), using data taken from both Platts and Bloomberg. Staff's goals were to ascertain what the actual price level was during that period, and whether any change in prices could reasonably be attributed to Enron's exiting the energy market.

Staff found that: (1) the price drop was in fact smaller than Dr. McCullough testified; (2) that smaller price drop is consistent with historical price drops for that time of year (the seasonality factor); and (3) the precise amount of the price drop differs, depending on whether Platts' data or Bloomberg data are used.

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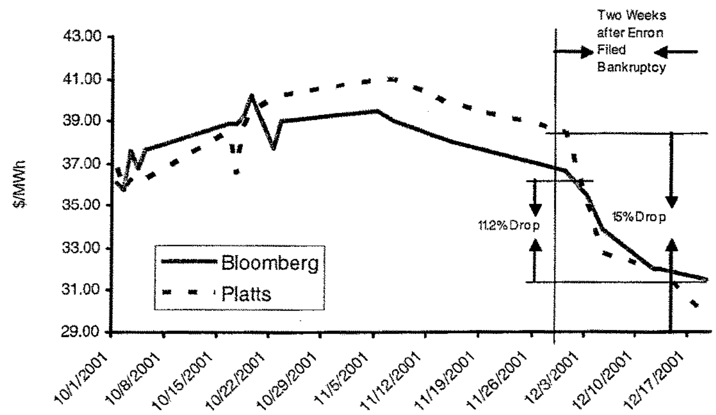
[45] "Western Senators Want to Know if Enron Manipulated the Market," *Power Markets Week*, February 4, 2002.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Figure 1 shows the forward electricity prices at Mid-Columbia reported by Platts and Bloomberg, respectively. While Platts examined the five-day period surrounding the Enron bankruptcy filing, Staff examined the two week period following the bankruptcy filing. Staff found that, using Platts' data, the forward prices in the two-week period after Enron filed bankruptcy dropped 15 percent (from $35/MWh on December 3, 2001, to

Figure 1: Electricity Forward Curves (2003) at Mid-Columbia Measured by Platts and Bloomberg



$29.75/MWh on December 19, 2001), but, using Bloomberg's data, the forward prices for the same period dropped 11.2 percent (from $35.48/MWh to $31.50/MWh).

While the price data from the two reporting firms produce different results, they each indicate a drop in prices. Staff then examined what could be likely factors to explain that drop. We examined the historical trends in forward pricing to assess whether the drop in price at Mid-Columbia at the time of the Enron bankruptcy was significantly different from previous years, that is, whether seasonality was a factor. Seasonality is an important feature of both electricity spot and forward markets. The demand for electricity varies by season, with the strongest demand usually in the summer.

Staff analyzed historical data on electricity futures to see if there is any monthly pattern. We calculated seasonal factors (SFs) using NYMEX futures prices at two delivery points, the California-Oregon Border (COB) and Palo Verde,[46] using five years of monthly data (1996-2001), as shown in Figure 2. While COB is geographically proximate to Mid- Columbia the Northwest, Palo Verde is in Arizona. The Palo Verde data is still significant because the West is a single market where energy is often traded due to seasonal diversities. An SF greater than 100 denotes a period in which futures prices are greater than the yearly average, while the reverse is true if the SF is less than 100.

As shown in Figure 2, prices normally fall from November to December, and December's futures price is typically lower than the yearly average and also the lowest in the second half of the year. In fact, prices fall on average from November to December by about 15-18 percent, in line with the 11-15 percent drop at COB from November to December 2001.

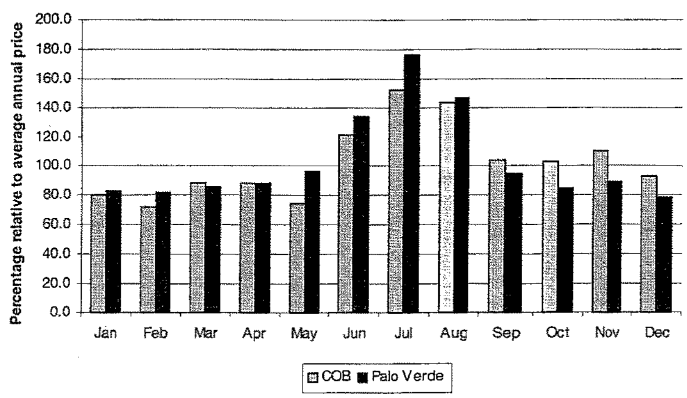
[46]Calculating SFs requires at least four-years of data. Accordingly, Staff used NYMEX futures data for COB and Palo Verde because the NYNEX COB and Palo Verde futures are the only futures or forward markets that have four-year data. Seasonal adjustment "requires at least four full years of data". *See* Eviews User's Guide, 1994-1997, Quantitative Micro Software, page 183.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

In short, Staff concludes that the fall in prices in December 2001, whether measured by Platts' data or Bloomberg's data, is more likely to be related to historical seasonality than to be attributable to any one specific, non-recurring event, such as Enron's bankruptcy. We caution, however, this does not mean that Enron did *not* manipulate markets, only that Enron's bankruptcy cannot be viewed as the principal trigger for a drop in forward prices at Mid-Columbia in December 2001, since that actual price drop is in line with historical price trends.

While Staff can attribute the fall in forward prices at Mid-Columbia in December

Figure 2: COB and Palo Verde Monthly Futures Prices



2001 to seasonality, we cannot readily understand the discrepancy in the prices reported by Platts and Bloomberg for that period. This concerned Staff for several reasons. First, the natural gas and electric industries generally rely on published price data, and assume that the published data is reasonably accurate, unbiased, and reliable. Second, Platts publishes two of the natural gas price indices that are used in calculating the MMCP in the California refund proceeding.[47] Third, the accuracy of historical published data was essential to Staff's ability to determine whether Enron, or any other entity, had in fact manipulated prices. Therefore, it is critical that Staff examine the reliability of published price data.

C. Description of the Reporting Firms' Procedures and Practices for Published Price Data (Spot and Forward Prices for Natural Gas and Electricity)

In order to explore the reliability of published price data, and also in order to analyze the correlation between spot prices at California delivery points and spot prices at other trading points, including Henry Hub, Staff issued data requests to Platts and Bloomberg to determine the respective differences in their sampling and reporting procedures. To ensure completeness, Staff requested information on spot and forward prices for both electricity and natural gas products in its data requests. For electricity products, there are both daily spot and daily forward prices. The published spot prices are a weighted average of the previous day's reported prices. Because the forward electricity market is relatively illiquid and trading activity can vary significantly from day-to-day, the published forward prices are more difficult to calculate, and the reporting firms rely more on the judgment of their reporters.

Staff's questions focused on the reporting firms' sampling procedures, index calculation methodologies, and their internal verification procedures. Specifically, Staff asked the reporting firms the following questions:

- What are your general sampling procedures and coverage for forward trades?
- What products do you include in your forward prices?
- How are reporting locations treated?
- What is the basis for reported prices?

[47]More specifically, the formula for calculating the MMCP relies on an average of the California spot market prices published from the following multiple sources: *Gas Daily* and Inside FERC's *Gas Market Report* (both published by Platts) and NGI's *Daily Gas Price Index.*

- How do traders report prices to you?
- Are firms required to participate? Are they subject to periodic audit or compliance?
- Do you verify or validate the data you collect with other sources? If so, how are the data verified or validated?

The firms were also asked to provide any available written internal documentation of their information gathering and index calculating procedures.

The specific data gathering, price calculating and information verifying procedures of each of the reporting firms are described below and come from reporting firms' responses to Staff data requests.[48] Staff's information requests are public, and are posted on the Commission's web site for Docket No. PA02-2-000. One reporting firm, Platts, filed its responses under a claim of privilege pursuant to 18 C.F.R. § 388.112 (2002); under this regulation, such material is to remain non-public unless a Commission official denies the claim of privilege and provides the filing party with no less than five days' notice before public disclosure. Thus, a summary of Platts' responses is not included in this report. Nonetheless, Staff's conclusions are based on its review and analysis of Platts' non-public responses, and Platts' responses were extremely valuable in Staff's understanding and assessment of the price indices.

1. Electricity

a. Platts

As previously noted, Platts filed its responses under a claim of privilege. In addition, Platts declined to respond to certain aspect of Staff's data request to protect the confidentiality of its sources. While Staff will therefore not summarize Platts' responses, we will provide a general overview of key themes.

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[48]The data requests are as follows: Platts Electricity Products, April 11, 2002 (Platts Electricity Data Request) and May 31, 2002 (Platts Follow-up Request); Bloomberg, April 11, 2002 (Bloomberg Data Request) and May 2, 2002 (Bloomberg Follow-up).

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

In general, Platts develops spot price data through a survey of the electric market, while daily forward assessments reflects Platts' subjective opinion on the value of forward contracts at the end of the day. With respect to valuation, Platts relies on the experience and judgment of its reports to identify and discuss any invalid information and does not subject the firms reporting to it to any formal audit or compliance measures. As noted earlier, Platts is now in the process of refining its methods to put a premium on verifiability and quality of data. This process will include a standard spreadsheet with columns for counter party and whether a transaction is a purchase or a sale, enabling Platts to cross-check each transaction for accuracy.

b. Bloomberg

Bloomberg does not report actual trades. Rather, it collects data on bids and offers for forward power transactions.[49] It collects the data from traders on a voluntary basis; that is, it accepts the bid and ask data from those traders who are willing to provide such data.

Bloomberg states that it has no selection criteria with respect to the traders from whom it receives data.[50] Bloomberg describes its price reporting methodology as follows:

> In computing the index price, Bloomberg's electricity market reporters survey a broad cross section of the OTC [over-the-counter] power market to include brokers, traders, investors, and municipally-owned electric utilities, as well as power marketing companies. After collecting prices, reporters add up volumes and prices or post the most frequently quoted forward electricity price for the specified location and period.[[51]]

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[49] Staff notes that the Commission purchases data from Bloomberg (and other entities) which it uses as part of its market monitoring program.

[50] Response dated May 9, 2002, to Bloomberg Data Request in Docket No. PA02-2-000.

[51] Response dated May 9, 2002, to Bloomberg Data Request in Docket No. PA02-2-000 (printout from the Bloomberg help screen).

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Bloomberg states that its reporters call a variety of parties to prevent one source's pricing from being given too much weight in the index. It also states that its index price methodology is designed to ensure that smaller market players, such as municipal electric utilities, are used to create the benchmark electricity prices that may have an effect on investors and ratepayers.[52]

2. Natural Gas

In addition to publishing electricity price data, Platts reports prices for natural gas. Natural Gas Intelligence (NGI) and Energy Intelligence Group also publish natural gas prices. Thus, for the purposes of gathering information on natural gas price reporting, Staff sent data requests for these three reporting firms.[53]

Staff asked Platts Natural Gas Products (publisher of *Gas Daily* and *Inside FERC Gas Market Reports*), NGI, and Energy Intelligence Group the following questions about their sampling procedures, index calculation methodologies, and internal verification procedures:[54]

- Describe the history of price posting for Southern California Gas and Pacific Gas and Electric for both *Gas Daily* and *Gas Markets Report*.

- To what extent did the firm use prices posted on EOL in developing the prices it posted?

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[52]In addition, Bloomberg represents that it operates a many-to-many electricity trading exchange, *Powermatch*, that matches willing buyers and sellers. Bloomberg states that it does not take a position on any of the trades.

[53]While Bloomberg also publishes natural gas price data, that data is not used in any Commission proceedings, unlike those of the other reporting firms, nor does Bloomberg publish data about actual trades. Thus, Staff determined that it did not need any further information from Bloomberg.

[54]The data requests are as follows: Platts Natural Gas Products, May 21, 2002 (Platts Natural Gas Data Request); Natural Gas Intelligence, May 23, 2002 (NGI Data Request); and Natural Gas Weekly, May 23, 2002 (Natural Gas Weekly Data Request).

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

- To your knowledge, to what extent did market participants use EOL as a price discovery mechanism for natural gas prices?

In all cases, there is the issue of product definition. For natural gas products, there are daily, weekly, and monthly prices reported. As with electricity prices, the published daily spot prices are a weighted average of the previous day's reported prices. Published weekly prices are a weighted average of the week's daily spot prices. The monthly prices are for "baseload" purchases that flow for the entire month and are normally made during the bid-week of the previous month.[55]

One reporting firm, Platts, filed its responses under a claim of privilege pursuant to 18 C.F.R. § 388.112 (2002); under this regulation, such material is to remain non-public unless a Commission official denies the claim of privilege and provides the filing party with no less than five days' notice before public disclosure. Thus, a summary of Platts' responses is not included in this report; nonetheless, Staff's conclusions are based on its review and analysis of Platts' non-public responses.

a. Platts

As previously noted, Platts filed its responses under a claim of privilege. In addition, Platts declined to respond to certain aspect of Staff's data request to protect the confidentiality of its sources. While Staff will therefore not summarize Platts' responses, we will provide a general overview of key themes.

In general, Platts develops its posted natural gas prices primarily through interviews on the telephone or through faxes with various market participants. Platts collects information on price, volume, and sometimes counter parties. Platts then sorts the prices from high to low, looks for outliers, and cross-checks with the counter parties whose names it has. None of the data is subject to external audit or validation. As noted earlier, Platts is now in the process of refining its methods to put a premium on verifiability and quality of data.

b. Energy Intelligence Group

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[55]The "bid-week" price is the volume-weighted measure of gas prices for the following month done during the pipeline nomination period.

Energy Intelligence Group publishes *Natural Gas Week*, which reports weekly and monthly bid-week natural gas prices.[56] Its price indices use a volume-weighted average of individual natural gas spot transactions reported to its staff by participants. *Natural Gas Week* requires that each company that it surveys provide both price and volume for each reported trade. It states that it acquires price data from market participants with varying interests in order to ensure accuracy:

> Each day, participants in the natural gas market – net buyers, net sellers and marketers – are polled to ensure that the parties with diverse interests are part of the survey. For each participant with an interest in seeing a high posted price, we poll one with an interest in seeing a low posted price.[[57]]

In addition, *Natural Gas Week* states that it is able to identify the counter-parties to each trade and any anomalies in terms of volumes or price. It also states that any anomalies are researched to verify whether there was an operational issue in the marketplace, and if not, the data are discarded from the survey. If a participant is found to be reporting volumes or prices that are out of line with the rest of the survey, that participant is no longer polled. Finally, *Natural Gas Week* stated that "[c]ommunications between the *Natural Gas Week* staff and market sources is deemed proprietary by our company."[58]

c. Natural Gas Intelligence

NGI publishes NGI's *Daily Gas Price Index* and NGI's *Weekly Gas Price Index.* NGI describes its data collection methodology for its publications as follows:

> Intelligence Press gathers the data used in setting prices via a daily telephone and fax survey of industry representatives. Our source base consists of more than three hundred participants from all sectors of the natural gas industry and its customers. By obtaining quotes from a large

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[56]The bid-week price is the volume-weighted measure of gas prices for the following month done during the pipeline nomination period.

[57]Response dated June 4, 2002 to Natural Gas Week Data Request in Docket No. PA02-2-000.

[58]*Id.*

> sampling of producers, marketers, intrastate pipelines, industrial end-users, and utilities, we increase the likelihood that the prices appearing in the newsletter more closely approach the true population average in an objective manner. In the survey, we ask our participants whether they have purchased or sold any gas, and if so, for what period, into which pipeline(s) or at what citygate, and at what price and volume. Normally, we will also discuss the present market conditions which are influencing prices, such as weather, storage, available supply and pipeline capacity, prices of competing fuels, and the effect of futures trading. Data gathered in the survey are used in calculating both the weekly GPI and the Daily GPI spot market prices.[[59]]

NGI states that it does not include transactions tied to an index, either its own or that of another publication. It notes that it recognizes that including index prices in the index would raise the question: "is the market determining the index or are index deals determining the market?"[60] Finally, NGI states that it "does not reveal the source of any price information, nor will we reveal the parties involved in any transaction to any outside organization."[61]

D. Based on the Responses, Staff Finds That Published Price Data Are Susceptible To Manipulation and Cannot Be Independently Validated

Based on our review of the responses to our data requests, Staff determined that published electricity and natural gas price data are based on trades or bid/ask prices reported by traders and other market participants. The reporting firms state that they rely on traders believed to be reliable, but they conduct varying degrees of formal verification or corroboration, through, for example, cross-referencing reported trades, of the information they receive.

Staff is troubled by the lack of reported formal verification or corroboration that the reported firms state they performed. This opens the door for entities to deliberately misreport information in order to manipulate prices and/or volumes for both electricity

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[59]Response dated June 4, 2002, to NGI Data Request in Docket No. PA02-2-000.

[60]*Id.*

[61]*Id.*

and natural gas. In the absence of some form of double-checking, such misreporting is likely to be undetected in the reporting process and uncorrected when prices are published.

Certainly, there is a significant incentive on the part of certain market participants to deliberately misreport prices, given that natural gas is the fuel input for the electricity generators that set the market price in California and the rest of the West. Unscrupulous traders could manipulate natural gas price indexes in order to increase the profitability of their electricity positions. The means by which this misreporting could occur is actually quite simple. Traders overstate prices to the reporting firms, which in turn publish price data that incorporate the overstated prices. Buyers and sellers themselves cannot verify those prices because different reporting firms report information differently, *e.g.*, end-of-day vs. average, trades vs. bid/ask postings. However, the natural tendency is for buyers and sellers to assume that the published prices are accurate, so an overstated published index may then affect the actual price buyers pay for transactions. Thus, misreported prices could become part of the price formation process and adversely affect the true market price.

At this point in time, the Commission cannot validate published price data. This is due, in part, to the reporting firms' status as non-jurisdictional entities as well as their legitimate desire to protect the confidentiality of their sources. Without knowing the source of the raw data, there cannot be any independent validation of the price data published by any reporting firm. This is a particular problem for California delivery points price data, given the incentive to over-state prices in the West and in California. It is Staff's belief that this is one of the factors that makes the published natural gas price data for California delivery points inappropriate for setting the MMCP in the ongoing California refund proceeding.

E. The Effect of EOL's Dominance on Published Price Data

Another troubling aspect of published price data was the role that EOL played as a significant, even a dominant, source of price discovery for natural gas products. This, in turn, may have led to significant errors in the price data, especially when coupled with the reporting entities' failure to use statistically sound methodologies and to conduct verification of their data. These factors all enhance the opportunity for the deliberate misreporting of information for financial gain.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

In its response to the Staff's data request, NGI reported that a number of its sources indicated that, for several natural gas trading points in Southern California, EOL was their primary price discovery mechanism, and was used even by those traders who do not transact on EOL. NGI stated:

> Some [sources] even indicated that though they did not trade on the EOL system, they, nonetheless, closely watched the prices posted there.[[62]]

Many of the trades that were the source of published price data were conducted on EOL. For example, NGI informed Staff that EOL sent it aggregate daily data, which NGI printed in a separate table that included only data from electronic trading systems. NGI states that it did not independently access specific trading data taken directly from the EOL trading platform. In addition, NGI reports that a large amount of the data collected from sources other than EOL in fact represented trades actually conducted on EOL. Staff is continuing to explore how Enron and other sent data to the reporting firms.

EOL's former prominence may have been a significant source of error, both actual and potential, in the price reporting process. That is, there was a self-referential or circular nature to the prices being reported to the reporting firms because of how traders relied on EOL:

- Many market participants used EOL for price discovery;
- Because of the large quantities traded on EOL, a price posted on EOL would often be used by a trader as its own when contacted by the reporting firms;
- Even if the reporting firm had in fact randomly sampled traders (of which there is no evidence), the traders would be reporting the same prices they saw on EOL; and
- Traders' bids and offers that were posted on EOL in turn were based on the prices published by the reporting firms.

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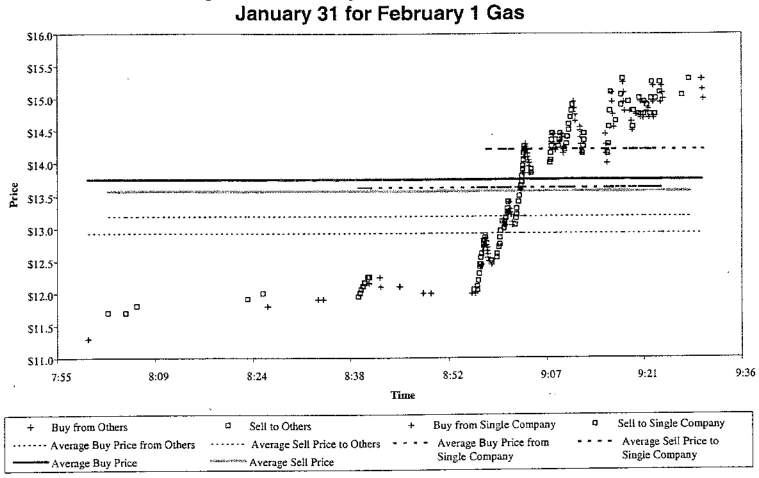
[62] June 4, 2002, response to NGI Data Request under Docket No. PA02-2-000.

The general reliance on EOL raises significant concerns.

Figure 3 illustrates the significance of EOL on the trading of natural gas for delivery into California, using data extracted from EOL databases. Figure 3 shows the trading activity on EOL on January 31, 2001, for next-day gas at the Topock delivery point. On that day, there were 227 trades made on EOL for next-day gas at Topock. The price rose from $11.30/MMBtu to $15.00/MMBtu. Of the 227 trades, 174 were made with a single counter party. The total volume on EOL for next-day Topock gas for the day was 2,240,000 MMBtu, of which 1,740,000 MMBtu was with that single counter party.

**Figure 3: EOL Day-Ahead Trades Topock
January 31 for February 1 Gas**



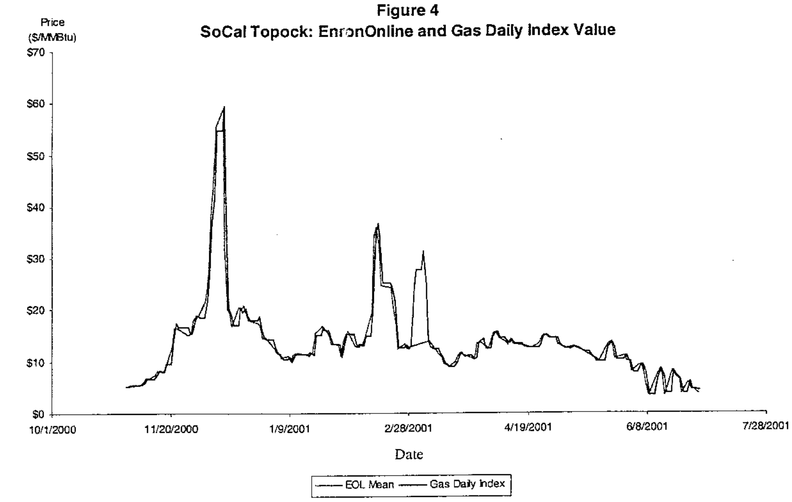
Total trading volume at Southern California Topock reported to *Gas Daily* was 6,766,000 MMBtu, which was the busiest trading point for that day. For February 1 at Topock, based on trades that took place on January 31, *Gas Daily* reported that prices ranged from a low of $11.10/MMBtu to a high of $16.05/MMBtu with an average price of $13.58/MMBtu. For February 1 at Topock, based on trades that took place on January 31, EOL's prices ranged from a low of $11.30/MMBtu to a high of $15.30, with an average price of $13.67/MMBtu. Absent the trades with this counter party, the EOL average prices for the day would have been lower. These trades, both purchases and sales, took place at higher prices than trades with other parties.

Of the 174 trades between Enron and this single counter party on this day, Enron bought 101 times and sold 73 times. This amount of trading activity may or may not meet a legal definition of "wash trading." Nevertheless, it shows an amount of trading that is difficult to rationalize as a normal or standard business practice. Figure 3 does not necessarily prove that Enron and the counter party were manipulating prices through their trading activity on EOL. But it does show the dramatic increase in price during the day and the significance of one trading partner during the price increase in the last hour of trading. Moreover, given the reporting firms' description of their price reporting procedures, Figure 3 illustrates the influence of EOL on published price data and the asymmetry of the information available to various market participants. The amount of trading between Enron and this counter party was more than three-fourths of the trading activity on EOL and more than one-fourth of the volume of total trading for the day at Topock reported by *Gas Daily*. Absent independent validation of raw data, only Enron and possibly the counter party could have known that so much of the trading was going on between themselves, because parties looking at EOL's screens could only see the bid and ask prices; they could not know who the counter party was on any particular trade.

Staff recognizes that there may be reasonable explanations for a flurry of purchases by a single counter party on EOL. For example, a buyer might simply need the gas. However, the trading activity on January 31, 2001 raises questions. The counter party's net spot purchase for the day was 280,000 MMBtu. As noted above, that counter party's trading volume for the day on EOL was 1,740,000 MMBtu. For the day, the counter party bought 1,010,000 MMBTu and sold 730,000 MMBtu, with almost all of that activity occurring in the last half hour of trading. If the counter party were simply buying the gas in the spot market to serve its burner tip needs for the next day, it would not have needed to buy over one million MMBtu of natural gas and sell back over seven hundred thousand MMBTu on EOL in a half hour, as the price rose by more than $3.00 per MMBtu. Moreover, such a burst of buying activity would almost surely have a maximal rather than minimal price effect, as reflected in the steep price increase shown in the last hour of trading in Figure 3. Normally a net buyer would not be interested in raising the market price.

Staff further recognizes that trading natural gas is a complicated business and traders may have reasons to buy and sell significantly more than the amount of their net position. However, the data show that the counter party was the largest purchaser of spot gas at Topock on EOL and, unlike other buyers and sellers on EOL, its trading volume was significantly greater than its net position. For example, a typical trader that was a net buyer of 100,00 MMBtu might buy 120,000 MMBTU and sell 20,000 MMBTU, whereas the counter party might buy 500,000 MMBtu and sell 400,000 MMBTu to reach the same net position. Staff is continuing to investigate the trading behavior on this and other days with apparent anomalous trading patterns and examining the companies' related financial derivative positions.

Figure 4
SoCal Topock: EnronOnline and Gas Daily Index Value



In short, the price data published by the reporting firms would only show a large price movement. No reader would know that a large percentage of that trading activity was between two specific parties, Enron and this single counter party, because the reporting firms would only receive an average price and daily volume at a given trading point on EOL. Therefore, traders are in a position to report incomplete, and potentially misleading, price data to the reporting firms.

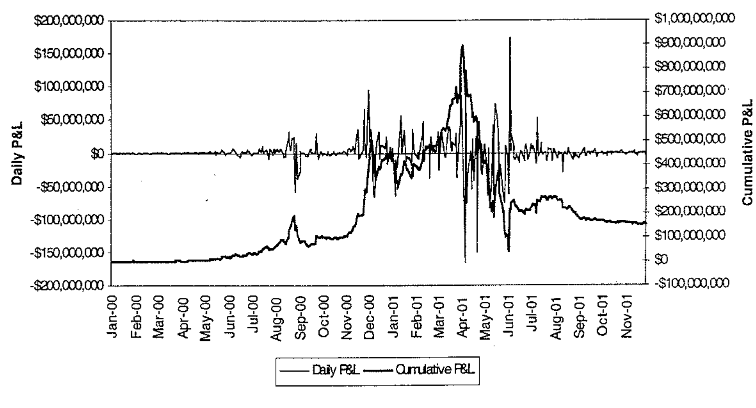
Again using data extracted from EOL databases, Staff attempted to determine whether EOL was a significant source of price information for published price data. As shown in Figure 4, the *Gas Daily* Index price for October 2000 into July 2001 closely tracks the EOL mean price for the day. This is consistent with reports that EOL was a prominent source of price information for the published Western natural gas price data during 2000 and 2001.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Given that EOL was such a significant source of the price discovery and formation process, it is useful to understand how Enron traders operated in the Western natural gas markets. Figure 5 provides information about the Enron trading in Western natural gas markets and shows that Enron traders took significant positions in those markets. Using data on Enron traders' profits and losses taken from Enron's databases, Figure 5 shows the cumulative profitability of the positions taken by Enron traders and the extreme volatility of their returns. As shown in red on the right vertical axis, the cumulative profit from Enron's Western natural gas trading, from June 2000 to April 2001, was approximately $900 million. By July 2001, Enron's cumulative profit for trading Western natural gas on EOL had fallen back to close to zero. In addition, the left vertical axis (shown in blue) shows the increase in the daily swings in profits and losses. For the first five months of 2000, the daily changes were close to zero. By contrast, from late 2000 into June 2001, there were daily swings in excess of $100 million. Staff notes that this period of time coincides with the time that electricity prices in California were the most volatile.

In addition, internal Enron notes and training exercises gathered by Staff in the investigation indicate that Enron was aware of the potential to influence the published

Figure 5
Daily and Cumulative Profit & Loss (P&L) for Trading in Monthly Western Gas Contracts 2000 to 2001



price data in order to profit in its related derivative positions and was considering the legal implications of doing so. Staff is continuing to investigate whether Enron has engaged in manipulative trading activity.

In short, the particular reporting methods used by any reporting firm are almost irrelevant, as long as its data sources themselves were biased due to substantial reliance on EOL. Using EOL, an Enron affiliate was always one of the parties to a transaction, and sometimes Enron affiliates were on both sides of a transaction, which gave Enron an easy means by which to influence the bids and offers posted on EOL, and the prices charged for transactions. In addition, the empirical evidence based on the data from EOL databases suggests that EOL was indeed a significant part of the price formation process, and that Enron took large positions in the markets using EOL. This gave Enron

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

significant ability and incentive to manipulate the price data published by the reporting firms. Furthermore, internal memos indicate that Enron understood its ability to affect the published price data and the financial incentives it had to drive up the reported index prices. Staff is still in the process of examining the data from the EOL database system and is continuing to investigate whether the posted prices were subject to manipulation.

F. The Effect of Wash Trading on Published Price Data

There have been widely-reported press stories about wash trading in both natural gas and electricity. Staff's effort to study the effects of wash trades on markets is being coordinated with the CFTC and the SEC.

For the purposes of this initial report, we focus on the question of whether wash trading can be used to manipulate price data or otherwise adversely affects the accuracy of published price data. Staff believes that wash trading can adversely affect the accuracy of published price data under certain circumstances. For example, wash trading provides the illusion of a deep market (that is, more volume than absent wash trades), which may lead buyers to assume they are getting a competitive price and trading in a liquid market when in fact they are not. Another problem is that, because the daily closing price is often based on the last trade, a wash trade at the end of a trading day could be used to deliberately move that price. In fact, Platts indicated that its forward price data is meant to mirror the end-of-day price used in mark-to-market accounting. In a thinly-traded market, *e.g.*, forward markets, one wash trade could move the market price.

As an example, using data from the Enron database system, Staff identified a number of trades between an Enron trader and the same counter-party that appeared to be wash trades. For purposes of identifying these trades, Staff looked for transactions that were a buy and sell between the same counter parties for the same product at the same price within a two-minute period. Overall, we have retrieved information indicating that Enron may have been involved in considerable electricity and natural gas round trips or wash sales. In one instance, a number of apparent wash trades with the same counter-party is apparently explained by the fact that the counter-party to the trades was participating in a promotional campaign run by Enron in an effort to benefit personally by recording the largest volume of trades.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Because there is no way to validate the data given to the reporting firms, the possibility of a detrimental effect on prices cannot be discounted. Staff will continue to assess the role that wash trades play on the prices for natural gas and electricity.

G. Problems Specific to Published Natural Gas Price Data for California Delivery Points

In addition to the characteristics and problems in published price data discussed above, none of which is specific to California, Staff has reason to conclude that the reporting of natural gas prices in California has its specific, additional problems. First, there are numerous delivery points into Southern California, and, at least in part due to the regulatory structure of the California natural gas market, prices can be significantly different at the various delivery points.

Second, firms have incentives to overstate the price they pay for natural gas in order to affect the index price. These incentives include: (a) a higher index price will reduce their refund exposure for electricity (increased natural gas prices raise the market-clearing price);[63] and (b) a higher index price will allow them to benefit from state-level performance-rate incentives.[64]

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[63]For example, a gas-fired generator with a heat rate of 15,000 Btu/kWh that paid $12 per MMBtu for natural gas produces electric energy at a rate of $180/MWh. As a point of reference, in December 2000, the natural gas index price at the Topock delivery point in California reached $60/MMBtu. If the true cost of fuel were $60/MMBtu, the same generator's cost of producing electric energy would be $900/MWh. During this period, the market-clearing price in California did not come close to $900/MWh. This fact indicates either that no generators actually paid $60/MMBtu, or those that did were selling electricity for less than their running cost or such generators were exporting energy to the Pacific Northwest, where prices were over $900/MWh. In this last case, the exporting of energy from California to the Pacific Northwest should not be relevant to price formation in California, unless that high-priced energy was re-imported to California as part of megawatt laundering. These export issues are discussed later in this report. In any event, either scenario casts doubt on the accuracy of the reported natural gas spot prices for that period.

[64]Each of California's three large natural gas local distribution companies has a gas cost incentive mechanism, under which it profits if it buys gas at prices lower than its reference benchmark price. While each company's benchmark reference is formulated differently, in all cases, California border prices are a key part of the benchmark. Therefore, higher reported prices drive up the benchmark and therefore benefit those companies. In addition, payments to gas-fired qualifying facilities in California are
(continued...)

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Having numerous entities with incentives to move the price in one direction makes price data particularly susceptible to manipulation. In addition, the number of trades at the specific points can be small at a given time, making them particularly vulnerable to influence by a few entities.

Furthermore, there are inconsistences in published price data in terms of the locations of the gas delivery points. For example, at one time, Edison and PG&E were treated as a single market. However, in different months in 1998, at least two reporting firms split that single market into two markets. Both of these reporting firms stated that the reason for the split was the existence of price differentials between the two points. In contrast, a third firm did not begin posting separate prices for Edison and PG&E until April 2001. That firm stated that it did not observe significant price differentials between the two points until late 2000. This illustrates the important point: the reporting firms have different views regarding something as fundamental as the definition of the market itself.

H. Conclusion

To sum, Staff has discovered the following major problems with published price data, including specific issues with respect to California delivery point spot prices:

- Historically, the spot prices for natural gas at the California delivery points highly correlate with prices at producing basis and Henry Hub. During the months of October 2000 to July 2001 – the refund period in the California refund proceeding – the correlation was abnormally low. Since that time, the high correlation has resumed.

- The Commission cannot independently validate the reporting firms' price data, and undetected errors may exist due to a lack of formal verification procedures.

- There are incentives for market participants to manipulate prices reported to the reporting firms, including incentives specific to California due to its regulatory structure.

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[64](...continued)
based on the reported Topock price, giving another large group of gas purchasers in California a reason to benefit from higher reported natural gas prices.

- Wash trading may have an adverse effect on reported price data.

- EOL was a significant source of price discovery and formation, and was potentially susceptible to price manipulation.

Staff concludes that published California natural gas price data are not sufficiently reliable to be used in the California refund proceeding for purposes of calculating the MMCP and resultant refunds. Staff makes no conclusions as to whether these reported prices are inappropriate for structuring contractual provisions between two sophisticated parties bargaining at arms-length. In the next section, Staff discusses its possible substitutes for the data.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

V. POSSIBLE SUBSTITUTES FOR CALIFORNIA DELIVERY POINT SPOT PRICE DATA IN THE CALIFORNIA REFUND PROCEEDING

A. How California Delivery Point Spot Prices Are Used in Calculating the MMCP for the Refund Period

Price mitigation for wholesale electric power sold in the Cal ISO and the Cal PX organized spot markets is different for two general time frames. For the first time period, October 2, 2000 through June 20, 2001 (the Refund Period), the Commission established a formula to set the MMCP and ordered an administrative hearing to determine whether refunds are owed by any sellers in the organized spot markets in California and, if so, how much. This determination is guided primarily by the Commission's order issued on July 25, 2001.[65]

For the second time frame, from June 21, 2001 until September 30, 2002 (the Prospective Period), the Commission adopted a prospective market monitoring and mitigation program designed to ensure that rates for spot sales throughout the Western United States remain just and reasonable. This program was prescribed in an April 26, 2001 order,[66] as amended by a June 19, 2001 order.[67]

On July 11, 2002, the Commission amended the calculation for the price cap for the Prospective Period and established a price cap of $91.78/MWh that would remain set at that level for the duration of the Prospective Period.[68] On July 17, 2002, the Commission issued an order that established a West-wide price cap of $250/MWh, effective as of October 1, 2002.[69]

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[65]San Diego Gas & Electric Co., *et al.*, 96 FERC ¶ 61,120 (2001) (July 25 Order).

[66]San Diego Gas & Electric Co., *et al.*, 95 FERC ¶ 61,115 (April 26 Order); *order on reh'g*, 95 FERC ¶ 61,148 (2001) (June 19 Order).

[67]San Diego Gas & Electric Co., *et al.*, 99 FERC ¶ 61,160 (2002) (May 15 Order).

[68]San Diego Gas & Electric Co., *et al.*, 100 FERC ¶ 61,050 (2002) (July 11 Order).

[69]California Independent System Operator Corporation, 100 FERC ¶ 61,060 (continued...)

For the Refund Period, the natural gas cost used in the formula to set the MMCP is derived from California spot price data published by the reporting firms discussed in the preceding section. The substantial portion of the MMCP is attributed to natural gas costs.[70] For this reason, and because it forms the basis for the calculation of potentially billions of dollars of refunds, it is critical that the source of the gas cost component be verifiable and statistically valid.

The Commission's July 25 Order established the scope of and methodology for calculating the MMCP related to transactions in the spot markets[71] in California, including the spot markets operated by the Cal ISO and the Cal PX,[72] during the Refund Period. The July 25 Order essentially adopted the criteria of the June 19 price mitigation plan with the modifications recommended by the Chief Judge in his report and recommendation issued on July 12, 2001,[73] that are appropriate for a past, rather than a future period.

As modified, this methodology for the calculation of the MMCP is based upon the marginal cost of the last unit dispatched to meet load in the Cal ISO's real-time market. Generally, the refunds are to be determined by the difference between the actual prices charged and a competitive market base-line, or the MMCP, calculated for each hour of the Refund Period.

The first step in calculating the cost of the marginal unit is the actual heat rate for every hour of the last unit dispatched in the Cal ISO's real-time imbalance energy market. The gas costs associated with the marginal unit are based upon the daily spot gas price because the Commission has historically used spot prices as a replacement cost of fuel.

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[69](...continued)
(2002).

[70]This report only addresses the gas cost component of the formula, which is derived from the published California spot price data discussed previously.

[71]"Spot market" sales are "sales that are 24 hours or less and that are entered into the day of or day prior to delivery." 95 FERC ¶ 61,418 at 62,545, n. 3.

[72]The California PX ceased its core market operations on January 31, 2001.

[73]San Diego Gas & Electric Co., *et al.*, 96 FERC ¶ 63,007 (2001).

Thus, the resulting calculation reflects the gas purchasing practices of sellers during the Refund Period.

However, because spot gas prices vary significantly between southern and northern California, a simple average of gas prices in the north with gas prices in the south does not adequately capture the significant effect of gas prices on the cost of electricity during the Refund Period. Thus, the methodology provides that, if the marginal unit is located North of Path 15 (NP15), the daily spot gas price for PG&E Citygate and Malin should be averaged with the resulting gas price multiplied by the marginal unit's heat rate to calculate the fuel portion of the clearing price for that hour. If the marginal unit is located South of Path 15 (SP15), the daily spot gas price for Southern California Gas Large Packages should be multiplied by the marginal unit's heat rate to calculate the fuel portion of the clearing price for that hour.

In order to reduce the effect of errors and other concerns that might occur in gathering and reporting the spot price data, the Commission determined that the daily spot prices are to be based on an average of the California spot market prices published from the following multiple sources: *Gas Daily*, NGI's *Daily Gas Price Index* and Inside FERC's *Gas Market Report*. However, because *Daily Gas Price Index* and *Gas Market Report* did not have a listing for Southern California Gas Large Packages during the Refund Period, the *Gas Daily* reported price is to be used for calculation of the southern gas price during the Refund Period. The last published gas prices should be used in calculating the refund price for the days that *Gas Daily* is not published (weekends and holidays).

In addition, the Commission recognized that a single methodology for calculating potential refunds for the Refund Period may not be appropriate for all sellers in the Cal ISO's and Cal PX's spot markets in an after-the-fact refund calculation. Accordingly, sellers not using the methodology bear the burden of demonstrating that their costs exceeded the results of this recommended methodology over the entire Refund Period.

A slightly different approach is taken for calculating the MMCP for the Prospective Period. In brief, the gas costs component are determined by the average of the mid-point of the monthly bid-week prices for Southern California Gas Large Packages, Malin, and PG&E Citygate. From June 19, 2001, until July 8, 2002, the mitigation cap ranged between $92/MWh and $108/MWh. On July 9, 2002 the Cal ISO recalculated the cap to $57.14/MWh, and, on July 10, 2002, again reset it to $55.26/MWh.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Then, on July 11, 2002, the Commission issued an order establishing a price cap of \$91.87/MWh for the duration of the Prospective Period.[74] As reported in Staff's January 31, 2002, report to Congress on the economic impacts on Western utilities and ratepayers of price caps on spot market sales, based on actual sales data for the period June 20, 2001 through November 30, 2001, spot market prices in California averaged approximately \$35 per MWh, well below the price cap of \$91.87 per MWh, and only a very few transactions even come close to the price cap. Therefore, this report makes no recommendations with respect to the calculation of the MMCP for the Prospective Period. Finally, as previously noted, the Commission in a July 17, 2002 order, established a West-wide price cap of \$250/MWh, effective as of October 1, 2002.

B. Staff's Recommendations on Proposed Substitutes

1. Summary of Recommendations

Staff makes the following recommendations with respect to the use of published natural gas price data in calculating the MMCP for the Refund Period:

The price data published in *Gas Daily*, *NGI*, and *Inside FERC Gas Markets Report* for the three California delivery points should not be used for calculating the MMCP for the Refund Period. While there may be other possibilities, we have focused our analysis on two of them. We are recommending that the MMCP should be calculated using producing basin spot prices plus transportation costs. Specifically, the MMCP for the Refund Period should be calculated using producing area prices from *Gas Daily,* plus an allowance for interstate natural gas pipeline transportation and local distribution company charges. For southern California, the average of the reported San Juan and Permian prices should be used. For northern California, the West Coast (Alberta) price should be used.[75] We discuss this recommendation in more detail below.

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[74]California Independent System Operator Corporation, 100 FERC ¶ 61,060 (2002).

[75]As noted above, to the extent that the California delivery point spot price data discussed in this report are used in other rate application proceedings before the Commission, the Commission should evaluate the appropriateness of continuing such uses.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Because natural gas at these producing areas is actually delivered to California, Staff believes that this alternative is superior to the other alternative which Staff considered, the price at Henry Hub. While Henry Hub is the most liquid natural gas market in the country, Henry Hub natural gas is not actually delivered to California. Either alternative is, however, superior (because each is more liquid) to the price data currently being used for the California refund proceeding, and either alternative is acceptable, given that prices at Henry Hub and at the producing areas highly correlate with each other. In contrast, the price indices currently being used for the California refund proceeding do not correlate well with Henry Hub prices.

2. Description of the Possible Substitutes

Given Staff's recommendation that the California spot gas price should not be used for calculating the MMCP for the Refund Period, we explored possible substitutes. In so doing, we kept in mind that the MMCP is intended to represent the price that a competitive power market would have reached, absent the dysfunctional conditions found to exist in the California markets.[76]

However, since gas and power markets were closely linked during the Refund Period, it is reasonable to conclude that California spot gas prices were driven to high levels by the same dysfunctions that afflicted the California power market. Therefore, to establish a valid proxy for the competitive power price, gas prices must be independent of the California power market. To meet this independence requirement, the substitute natural gas spot price data should be driven by general supply-demand forces. While there may be other possible substitutes, we examined in detail two possibilities for meeting this key criterion: the producing basins serving the California market and Henry Hub. We discuss each of them in turn.

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[76]*See* December 18 Order, 97 FERC at 62,171, 62,182, and 62,218; June 19 Order, 95 FERC at 62,558; San Diego Gas & Electric Co., *et al.*, 93 FERC ¶ 61,121 at 61,349-50 (2000); and 93 FERC ¶ 61,294 at 61,999 and 62,011.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

a. Producing Area Spot Price Data

In Figures 6 and 7 below, spot prices from these various producing areas are compared to California delivery point spot prices. The map of the western production basins and California delivery points shows the location of the trading points discussed in this section.

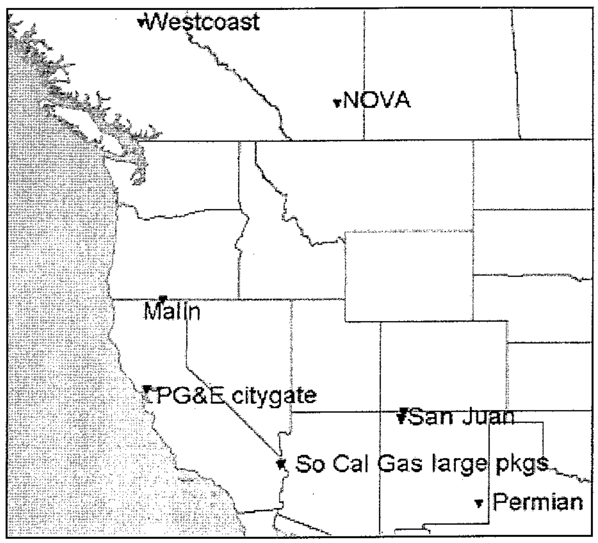
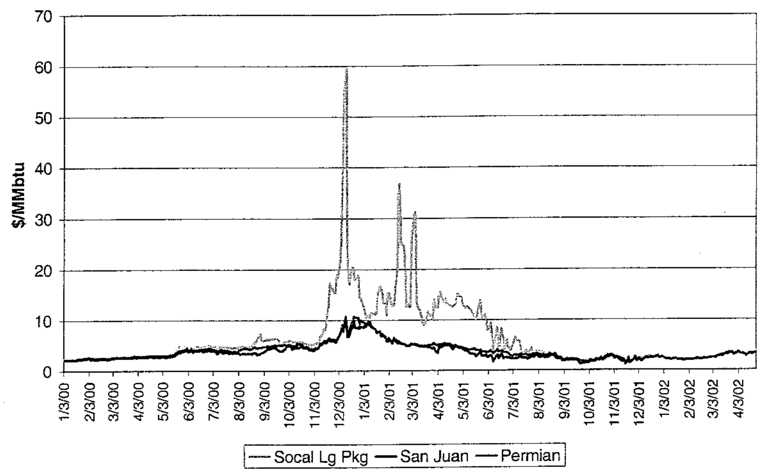


Figure 6 compares the southern California spot price (Southern California Gas

Figure 6: Southern California Spot vs. Producing Area Prices



Large Packages) to the San Juan and Permian basin spot prices.

Figure 7 compares the northern California spot price to the Alberta producing area spot prices (Nova and West Coast). Both figures show that the producing area spot prices did not display the volatility experienced in the California delivery point spot markets. Without the dysfunctions afflicting the California power market, the competitive spot price of gas serving California markets (absent the factor of scarcity[77]),

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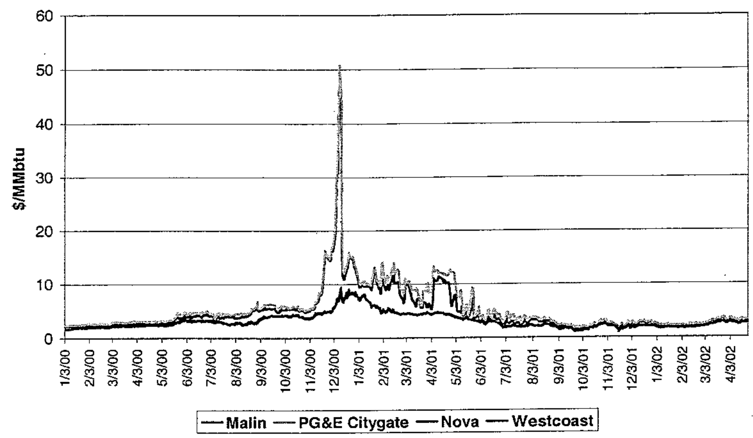
[77]We have not attempted to account for the effect of scarcity on price in evaluating possible alternatives to California spot prices. However, as discussed below, we would allow the opportunity to recover actual unaffiliated gas costs, which would operate as a backstop to recover any costs reasonably associated with scarcity.

20020813-0468 Received bv FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Figure 7: Northern California Spot vs. Canadian Producing Area Prices



should have closely tracked these producing area spot prices plus an allowance for pipeline transportation and distribution costs.

b. Comparison of Producing Area Spot Prices to Henry Hub Spot Prices

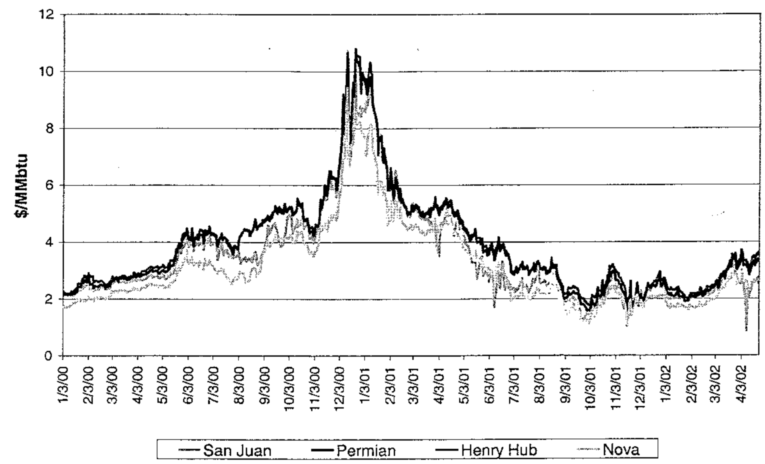
While the producing area spot prices did not reach the extraordinarily high levels experienced in the California gas spot markets, the question remains as to whether they are free of the infirmities we have found to exist in the California delivery point spot price data.

To answer this question, Staff compared the producing area spot prices reported by *Gas Daily* to the Henry Hub spot price. In Figure 8, the producing area prices reported by *Gas Daily* are compared to the Henry Hub price. This comparison demonstrates that the producing area prices track the Henry Hub prices fairly closely.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Differences between the two are logically explained. The San Juan basin prices are

Figure 8: Producing Area Prices vs. Henry Hub



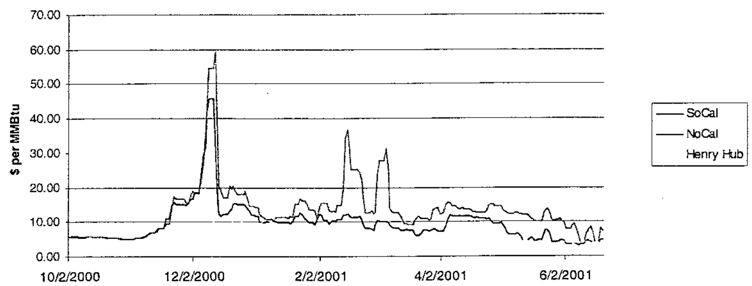
consistently a bit lower than Henry Hub reflecting the lack of multiple market outlets for San Juan gas. The Alberta prices are generally lower due to the higher transportation cost from Canadian sources to U.S. markets. The relatively close tracking of Henry Hub and producing area prices provides confidence in the use of either for proxy price determination. Staff selected Henry Hub as a benchmark because it is the most widely traded natural gas physical delivery point in the country and therefore is the most liquid market.

As shown in Figure 9, unlike the producing basins, the prices currently being used for calculating the MMCP in the California refund proceeding do not closely track the Henry Hub price. Using *Gas Daily* data for Henry Hub and the California delivery point price data currently being used in the California refund proceeding, the correlation coefficient between Henry Hub and the northern California price is .393 and the correlation coefficient between the Henry Hub price and the Southern California price is .573. As shown in Figures 6 and 7, this low correlation is primarily during the period

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

from October 2000 to July 2001. Historically, the correlation has been high, and is so today. The abnormally low correlation for this isolated period renders the prices at the California delivery points inappropriate for setting rates.

Figure 9: Index Prices for the California Refund vs. Henry Hub Price



The correlation coefficient can range from -1 to 1 with 1 meaning perfect correlation; 0 meaning no correlation; and -1 meaning perfect negative correlation. For comparison, for the Refund Period, the correlation coefficient between the Henry Hub price and the San Juan Basin price is .968; the correlation coefficient between the Henry Hub price and the Permian Basin price is .997; the correlation coefficient between the Henry Hub price and the West Coast basin price is .979; and the correlation coefficient between the Henry Hub price and the Nova basin price is .985.

As background, Henry Hub is owned by the Sabine Pipe Line Company and is located near the Gulf Coast in South Louisiana, where 14 pipelines converge near the supply region in Louisiana. It is one of the main entry points for Gulf production and can direct gas to a variety of market areas, including the Midwest, Southeast, and Northeast. It is the largest natural gas pooling point in the world, handling about one Bcf/day of physical flows. The two compressor stations that serve the hub can handle 1.9 Bcf/day. An average of five Bcf of gas is traded daily at the hub. The physical configuration of the system, coupled with the fact that there is little in the way of constraints (congestion) in and out of the hub, creates a very liquid market.

There is a linkage between the NYMEX natural gas futures contracts and the Henry Hub physical next-day gas trading.[78] NYMEX natural gas futures contracts are

[78]For a discussion of the relationship between spot and futures prices, see R. Pindyck, *The Dynamics of Commodity Spot and Futures Prices: A Primer*, Energy (continued...)

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

for delivery of natural gas for the entire next month at the Henry Hub. Settlement takes place at the close of each trading day. Buyers and sellers of natural gas at the Henry Hub use NYMEX natural gas futures to hedge their positions, even if they do not intend to take delivery of the natural gas in a specific NYMEX contract. Since, unlike electricity, natural gas can be stored, buyers with access to storage would be unwilling to pay significantly more for a NYMEX futures contract than the current next-day price. Likewise, sellers would be unwilling to sell gas for future delivery at a price significantly lower than the current next-day price. Therefore, the daily price of the next month NYMEX Henry Hub natural gas futures contract is highly correlated with the daily price for next-day physical gas for delivery at Henry Hub.

In addition, because of the direct linkage between Henry Hub and important delivery points in the Northeast and Midwest, the Henry Hub physicals and NYMEX futures tend to be relatively deep markets that are attractive instruments for many market participants, as these instruments are reasonably correlated with the hedging needs of many individual market participants. Consequently, the relative attractiveness to many of the other market participants leads to concentration of trading activity (volume) and market depth. Of course, as in various market settings, liquidity is self-reinforcing as

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[78](...continued)
Journal, Vol. 22, No. 3 (2001). As previously noted, Dr. Pindyck is one of the consultants to Staff for Docket No. PA02-2-000. In brief, this article explains that futures contracts have a daily settlement and corresponding transfer of funds at the end of each trading day. Dr. Pindyck states:

> Consider, for example, a futures contract for 1000 barrels of crude oil, for delivery six months from now. If the six-month futures price has increased by say, 40 cents per barrel during trading on Monday, the holder of the long position will receive $400 from the holder of the short position. If on Tuesday the futures price falls by 20 cents, $200 will flow in the opposite direction. This daily "settling up" reduces the risk that one of the parties will default on the contract. Payments are based on each day's settlement price, which is the price deemed by the futures exchange to be the market-clearing price at the end of the trading day.

Id. at 15. With respect to NYMEX Henry Hub futures, the daily settlement of next-month futures provides price information for the Henry Hub physical market.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

market participants have a strong incentive to trade using the deepest and most liquid markets. Trading activity attracts more trading activity and liquidity concentrates at the deepest markets.

NYMEX's markets play an important role in determining an appropriate benchmark for prices. NYMEX is an organized exchange subject to regulation by the CFTC (which in turn is subject to Congressional oversight).[79] As a regulated organized exchange, and in contrast to the unregulated reporting firms discussed earlier in this report, NYMEX is required by the CFTC, among other things, to maintain and to enforce internal auditing mechanism and to maintain painstakingly detailed records of trading activity so that a clear audit trail is possible.

The CFTC's key statutory responsibilities include ensuring the economic utility of the futures markets as hedging and price discovery vehicles, and also ensuring futures market and trade practice integrity, which in turn encourages fair competition.[80] Prior to December 2000, the CFTC approved all futures contracts, including Henry Hub futures contracts, before NYMEX could list such contracts and authorize trading. The CFTC reviewd the terms and conditions of such futures contracts and oversaw the registration of firms and individuals that either handle customer funds or give trading advice on futures contracts.

NYMEX is required to have in place approved rules for margin requirements and price and position limits. It also is required to conduct, with CFTC oversight, market surveillance and trade surveillance designed to prevent market manipulation and other anti-competitive activity and to discipline its members.

Through daily market surveillance, NYMEX monitors market participants and is able to analyze speculative participation, including the relationship between trading activity on NYMEX and fundamental factors in the cash market. Each day, NYMEX compliance staff compiles a profile of participants, identifying members and their

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[79]This discussion of NYMEX's organization and responsibilities is based in part on material written by NYMEX and available on its web site (www.nymex.com).

[80]This discussion of the CFTC's statutory responsibilities and its jurisdiction is solely the opinion of Commission Staff and does not represent the legal opinions or analysis of the CFTC. The CFTC may have a different view of the substance and scope of its jurisdiction and statutory responsibilities.

customers holding reportable positions. Daily market surveillance is performed to ensure that NYMEX prices reflect cash market price movements, that the futures market converges with the cash market at contract expiration, and that there are no price distortions and no evidence of market manipulation. Compliance staff holds meetings at least every week to review reports on fundamental factors affecting each traded product. Senior NYMEX officers attend these meetings as required.

NYMEX compliance staff is trained to detect such inappropriate practices as wash trading. If a trade appears suspicious, NYMEX may initiate a formal investigation, which allows compliance staff access to trading records for the party under review and key opposite brokers. This allows trade surveillance staff to reconstruct the audit trail and establish a chronology of the event. Trade surveillance staff employees rely on computer programs that provide real-time trading data and continuous on-the-floor monitoring.

The Futures Trading Practices Act requires that trade information be submitted to NYMEX and time-stamped within one minute of a trade. NYMEX requires its traders to use a special trading pad which provides NYMEX with an unalterable audit trail through the use of individually numbered, time-stamped computer scans of trader records. The information required to be submitted includes quantity, delivery month, price, the broker's badge symbol, and the badge symbol of the broker taking the opposite side of the trade. Members are penalized for failure to meet the one-minute submission requirement, since timely submissions are critical for ensuring the accuracy of the audit trail.

NYMEX also requires that floor brokers document each step in the trade execution process, thereby creating a detailed record of each trade which is sequentially recorded. As NYMEX itself explains, "Brokers recognize that a reliable audit trail protects them and their customers; the system guarantees that errors are quickly discovered and rectified."[81] Each trade executed on NYMEX is subject to computer analysis by NYMEX trade surveillance staff, which independently measure each broker's trading record submissions to determine their timeliness and accuracy. The analysis program isolates a broker's trades by type and against those of other traders.

[81]NYMEX, *Standards and Safeguards* (December 1995), at page 22.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Thus, the Henry Hub spot price index reflects a deep and liquid market used for both physical trading and financial futures trading on NYMEX, with the latter market being extensively policed by NYMEX itself and the CFTC.

As noted above, Figure 8 demonstrates that producing area spot prices closely track Henry Hub spot prices. Differences between the two are logically explained. The San Juan basin spot prices are consistently a bit lower than Henry Hub spot prices, reflecting the lack of multiple market outlets for San Juan gas. The Alberta (Nova) spot prices are generally lower due to the higher transportation cost from Canadian sources to U.S. markets. The relatively close tracking of the Henry Hub and producing area spot price data provides confidence in the use of the latter for proxy price determination. In contrast, the prices currently being used for the California refund proceeding do not correlate well with Henry Hub prices.

Staff considered, but ultimately rejected, recommending the use of Henry Hub spot price data as a substitute for California delivery point spot prices because natural gas from Henry Hub is not actually delivered to California. In contrast, natural gas from the producing areas is actually delivered to California. Thus, the use of the producing area spot price data seems preferable. Nonetheless, Staff regards either alternative as superior to the California delivery point price data.

c. Summary of Reasons Why Staff Recommends Producing Area Spot Price Data

Staff recommends that the producing area spot price data be used for refund determination purposes for several reasons. First, as shown in Figures 6 and 7, the producing basin price levels were substantially independent of the volatility afflicting the California spot gas and power markets. Second, the producing area prices correlate closely with the Henry Hub price (unlike the prices currently being used). Since Henry Hub has such a high physical trading volume involving a large number of entities, Staff considers the Henry Hub price an accurate reflection of supply and demand and a appropriate benchmark. The close correlation with Henry Hub prices provides assurance that the producing area spot prices also reflect general supply and demand forces. Third, since the producing area prices closely track Henry Hub prices, they appear to reflect the liquidity of Henry Hub. Fourth, the existence of a robust financial futures market based on delivery at Henry Hub, which is subject to formal auditing, surveillance, and other NYMEX and CFTC regulatory rules designed to detect inaccuracies and prevent market manipulation, provides another source of confidence in Henry Hub prices and in indices that correlate closely with those prices. Fifth, natural gas from the producing areas is actually delivered to California. We believe, therefore, that the producing area prices are the most appropriate source of the natural gas component for purposes of the calculating the MMCP for the Refund Period.

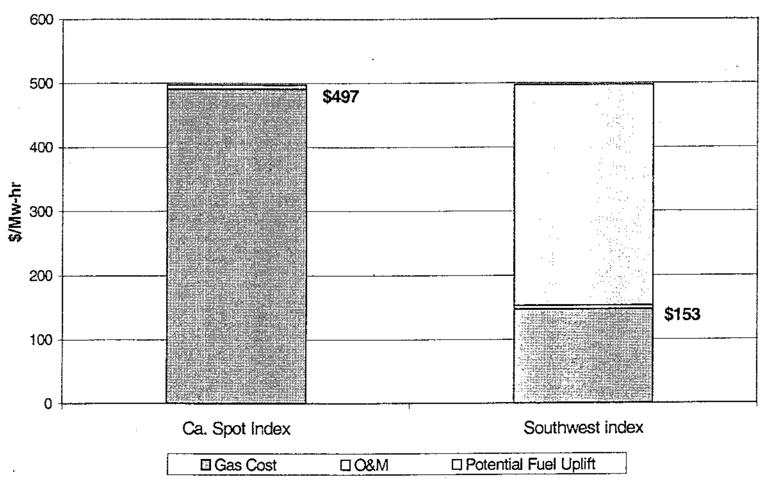
C. How the Substitute Natural Gas Index Would Work

Under Staff's recommendation, the MMCP would be computed based on the producing area spot price data from *Gas Daily* plus an allowance for interstate natural gas pipeline transportation and local distribution company charges. For southern California, the alternate index would be based on the average of the reported San Juan and Permian prices. For northern California, the West Coast (Alberta) index would be used.

Figure 10 illustrates how Staff's proposal would impact the MMCP for southern California. Take, for example, the market clearing price for December 12, 2000. The chart below compares the elements of the computed market clearing price for southern California power sales under the July 25, 2001 order and Staff's recommended proposal.

Under the original methodology using California delivery point spot prices, the gas cost component of the MMCP would be based a spot market gas price of \$32.75/MMBtu (Southern California Gas Large Packages) when the marginal unit that cleared the market was in southern California. Assuming a marginal heat rate of 15,000 MBtu/MWh, the July 25 methodology produces a price of \$497/MWh (including a

Figure 10:Market Clearing Prices - California Spot vs. Henry Hub Index December 12, 2000



\$6/MWh O&M allowance).[82]

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[82]The July 25 methodology also requires six ten-minute calculations to determine the hourly clearing price. Staff recommends that this methodology be retained. As explained earlier, the California Spot Index price shown in Figure 10 is the Southern (continued...)

For comparison, the gas cost component of the MMCP under Staff's proposed substitute (for this example) would be computed based on the average southwest basin price reported in *Gas Daily* of $8.84/MMBtu plus $0.977/MMBtu for total transportation costs, producing a revised MMCP of $153 per MWh. In either case there is an additional uplift for emission-related costs. Staff does not recommend changing the emissions uplift.

Finally, Staff recommends that the heat-rate component of the actual unit dispatched that cleared the market in the refund methodology in the July 25 Order remain in place. In the July 25 Order, the Commission found that it was not reasonable to use the heat rate from the marginal generator that should have cleared the market in a simulation of how the market would have been dispatched had there been a must-offer requirement in place (thus eliminating the effect of any physical withholding by generators). The Commission stated:

> We did not institute the must offer requirement or the marginal bidding requirement until May 28, 2001, and it is unreasonable to re-create the markets to apply such requirements for the period October 2, 2000 through June 20, 2001. Generators actually dispatched in the markets during these periods have specific marginal costs that are reasonably recovered under our methodology. The end result of using an assumed economic dispatch (prices lower than the actual marginal costs of the last generator dispatched) unfairly punishes the very generators that helped keep the lights on in California.[[83]]

In addition, Staff notes that using the producing area natural gas prices rather than the California delivery point prices in the refund calculation has a larger financial impact than using the heat rate of the unit that should have cleared the market under a simulation rather than using the value from the actual marginal unit that cleared the market. If, for example, the must-offer simulation resulted in the marginal heat rate falling from 15,000 Btu/kWh to 12,000 Btu/kWh, with a gas cost of $30/MMBtu, the gas component of the MMCP would fall $90/MWh (from $450/Mwh to $360/MWh). However, using the actual marginal heat rate of 15,000 Btu/kWh, if, for example, the gas input price changed

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[82](...continued)
California Gas Large Packages price published in *Gas Daily.*

[83]July 25 Order, 96 FERC ¶ 61,120 at 61,517.

from $30/MMBtu to $10/MMBtu, the MMCP would fall $300 (from $450/MWh to $150/MWh).

Generally, Staff's proposed substitute for the gas component of the MMCP would always consist of the reported basin price, a producing area to market transportation component,[84] plus an allowance for fuel.[85] The revised MMCP would set the new hourly clearing price. In addition, as discussed in the following section, Staff's proposal would allow for the recovery of additional actual fuel costs without affecting the clearing price. The revised MMCP would set the new hourly clearing price. In addition, as discussed in the following section, Staff's proposal would allow for an individual seller to recover additional actual fuel costs without affecting the market-clearing price.

D. Proposal to Recover Actual Unaffiliated Gas Costs

In the December 19 Order, as clarified in the May 15 Order, the Commission provided an opportunity for sellers, after the conclusion of the refund proceeding, to submit evidence as to whether the refund methodology results in a an overall revenue shortfall for spot power transactions during the entire Refund Period.[86] For the Commission to consider any adjustments, a seller must demonstrate that the rates were inadequate based on consideration of all costs and revenues, not just for certain transactions.

Some sellers may have incurred actual fuel costs higher than the producing area spot price plus transportation (*i.e.*, higher than the $9.82 in the above example). Staff

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[84]Estimated Southwest transportation costs: $0.651/MMBtu ($0.397/MMBtu for transportation from Permian to California (El Paso - Waha to Topock) plus $0.254/MMBtu for LDC transportation from Topock to the burner tip). Estimated Canadian supply transportation costs: $0.9224/MMBtu ($0.1820/Mmbtu within Canada plus $0.2722/MMBtu to California border on PGT-NW, plus $0.4682 on PG&E to the burner-tip).

[85]Fuel from Permian estimated at 3.74 percent. Fuel for Canadian supplies estimated at 4.43 percent. Total gas cost allowance including fuel from Permian: $0.984/MMBtu. ($0.651 plus 3.74 percent of $8.84 basin price for July 25, 2001), from Canada $ 1.314.

[86]December 19 Order, 97 FERC at 62,254; May 15 Order, 99 FERC at 61,652.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

recommends that the demonstration of a shortfall for all spot power transactions over the entire period be modified in several respects. First, generators should be required to use the average cost of their entire gas portfolio. Second, since generators may have purchased their gas supply from their gas marketing affiliate, Staff recommends that the true cost of gas to the generator should be based on purchases from non-affiliated entities only. Purchase prices from the generator's gas marketing affiliate are not the result of arms-length negotiations and reflect intra-corporate accounting rather than the true cost of gas. Where this is no unaffiliated entity in the transaction chain, Staff's gas index should be used. Third, the refund methodology should maintain a critical element of the single clearing price auction theory. By setting the clearing price using the least efficient unit, all more efficient units dispatched receive some contribution to their fixed costs. Therefore, Staff recommends that generators be allowed to retain this efficiency reward (that is, the revenues associated with the difference between the generator's heat rate and the heat rate of the generating unit that cleared the market.) The shaded area of Figure10 represents the potential range of the refund offset. The refund offset for a particular generator would depend on the cost of its unaffiliated gas purchases and its individual unit heat rates.[87]

Staff acknowledges that such events as the pipeline rupture near Carlsbad, New Mexico, in August 2000 may have resulted in scarcity of natural gas,[88] and that Staff has not attempted to quantify the effects of scarcity on price. This opportunity to recover gas costs based on prices paid to non-affiliates, as modified by the recommendations discussed herein, will operate as a backstop to allow parties to recover any costs reasonably associated with scarcity, which is not otherwise accounted for in the calculation of the MMCP.

Staff's proposed substitute is a regulatory solution to a market failure. Staff recognizes that the basis differential between trading points (in this case, between the western production basins and the California delivery points) represents differences in fundamental supply and demand conditions between points, particularly the scarcity of

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[87]For example, if a generator with a heat rate of 10,000 Btu/kWh has an average gas cost of \$30/MMBtu for purchases from non-affiliates and Staff's Henry Hub index is \$10/MMBtu, the generator would be entitled to apply for a refund offset of \$200/MWh for the entire Refund Period.

[88]During the winter period of 2000, when natural gas prices spiked, capacity was partially restored (average daily deliveries were reduced by approximately 10 percent).

natural gas due to limited gas transportation to California, and is an important signal for both buyers and sellers. Under normal circumstances, that basis differential should be preserved so that the MMCP is the true marginal cost of the last plant producing electricity in California. However, during the period in question, circumstances were not normal. California's electricity market was in crisis and the combination of the inelastic demand for electricity and the fact that natural gas was the fuel used by the marginal electricity generators was transmitting the problems in the electricity market back to the gas market. That is, electricity generators in California would be willing to pay almost any price for natural gas because they would be able to pass any gas costs through the wholesale electricity market. Given these conditions and the problems with the published California natural gas price indices described above, Staff finds that the proposed substitute, along with the opportunity to recover verifiable gas costs that reflect the scarcity premium, as specified above, is the best way for the Commission to establish just and reasonable rates for the refund period.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

VI. THE ENRON TRADING STRATEGIES

A. Introduction and Initial Recommendations

On Monday, May 6, 2002, Enron's Washington, DC counsel provided the Commission with three internal memoranda, two of which date from December 2000, that describe certain trading strategies employed by Enron's traders in the West. Enron's counsel informed Staff that Enron's Board of Directors had voted to disclose the documents and to waive all claims of privilege. The Commission made these documents publicly available on the web site for Docket No. PA02-2-000 within hours of receiving them.

In order to better understand the trading strategies discussed in the memoranda, which include, among other things, Enron receiving congestion payments without actually relieving any congestion, we issued that same day a follow-up data request to Enron. Among other things, we requested the production of any comparable memoranda that discuss trading strategies for natural gas products (since the memoranda only discuss electricity trading strategies). Finally, the data request asked Enron to provide us with all correspondence related to the subject matter of the memoranda.

The Enron memoranda allege that traders from other companies were also employing several of the trading strategies discussed in the memoranda. In order to pursue this issue, we issued, on May 7, 2002, a notice to all sellers of wholesale electricity and/or ancillary services in the West, informing them that we would soon be sending them a data request seeking information about their use of the trading strategies discussed in the Enron memoranda, and directing them to preserve all documents related to such trading strategies.

On May 8, 2002, we issued a data request to over 130 sellers of wholesale electricity and/or ancillary services in the West during 2000-2001, with a due date of May 22, 2002. This data request contained a series of requests for admissions, in which an officer of each company was required to admit or to deny, under oath, whether his or her company had engaged in specific activities described in the request. The specific activities were based on the trading strategies discussed in the Enron memoranda; in addition, there was a "catch-all" request for admission, asking the corporate officer to admit or deny under oath whether the company had engaged in any other trading strategies. The data request also sought production of all internal documents that relate to trading strategies that the company may have engaged in during the relevant time period, including correspondence between companies, reports, and opinion letters. We also requested information specifically with respect to any megawatt laundering transactions between any of these sellers and Enron.

This data request required that a senior officer of the company state, in an affidavit and under oath, that he or she conducted a thorough investigation of the company's trading activities in the West during 2000 and 2001 and that the information being provided in response to the data request is complete and accurate to the best of that person's knowledge and belief.

While Staff received over 835 MB of electronic data and numerous boxes of printed material in response to this data request, we did not obtain full compliance.[89] Therefore, on June 4, 2002, the Commission issued the Show Cause Order, directing four companies – Avista, El Paso Electric, Portland, and Williams Energy Marketing & Trading Company (Williams) – to show cause why their market-based rate authority should not be revoked. The basis of the Show Cause Order was the companies' failure to provide Staff with complete and accurate responses to the May 8 data request.[90] As discussed in Chapter III of this report, Staff has recommended separate company-specific proceedings for some of these entities.

While the exact economic impact of the trading strategies is difficult to determine precisely, Staff concludes that these now infamous trading strategies have adversely affected the confidence of markets far beyond their dollar impact on spot prices. Even those trading strategies which are not anti-competitive have been viewed by customers as clever exploitations of overly complex rules by companies that callously do not account for the impact of their decisions on prices and have lost sight of the fact that they are *public* utilities. There were no shortages of market participants from all sectors of the industry, including non-public utility entities such as municipals and governmental agencies in California as well as jurisdictional public utilities (including power

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[89]The data responses are among the material, public and non-public, that the Commission has provided to Congressional staff in response to requests for document productions.

[90]As previously noted, Staff has concluded that El Paso Electric and Williams have compiled with the Show Cause Order, and issued letters so stating, which are posted on the Commission's web page for Docket No. PA02-2-000.

marketers), who may have engaged in these trading strategies and in trading strategies of their own, which may have reduced the effects of Enron's trading strategies.

Staff's review of the evidence indicates that Enron, as a corporate entity, displayed great eagerness to experiment with all aspects of market rules and protocols in an effort to "game the system" or to simply provide false information. Enron's corporate culture, which permeated all of its affiliated companies, including those affiliates such as Portland which are not currently in bankruptcy, fostered a callous disregard for the American energy customer and demonstrates the need for more explicit prohibitions as well as aggressive market monitoring and enforcement.

In a market environment, one expects that traders, working within Commission-approved market rules, will utilize various strategies in an effort to maximize profits. But a fundamental aspect of some of the Enron trading strategies is the deliberate use of false information. A market cannot operate properly without accurate information. Implicit in Commission orders granting market-based rates is a presumption that the power marketer's behavior will not involve fraud or deception.

However, in light of the wide-spread nature of the Enron trading strategies, Staff recommends that the Commission require that all market-based rate tariffs include a specific prohibition against the deliberate submission of false information, or the omission of material information, whether to the Commission or to an entity such as an independent system operator, regional transmission organization, public utility, or market monitor. This tariff requirement should be worded broadly to cover any and all matters relevant to wholesale markets, including maintenance and outage data, bid data, price and transaction information, and load and resource data. By including these specific prohibitions, any revenues generated from transactions associated with such activities would be subject to refund under the FPA. This refund provision would be an effective means by which the Commission can better ensure that the conduct of public utilities in consistent with the public interest. Staff also recommends that all market-based rate tariffs include standard provisions so that the Commission can go beyond simply refunding profits and impose penalties on violators. Finally, Staff is aware that Congress is considering expanding the Commission's currently very limited civil penalty authority, and we strongly endorse expanded civil penalty authority that applies to jurisdictional companies that violate the Commission's orders and regulations, as a means to deter the types of conduct we have encountered in this investigation.

1. Overview of the Cal PX and Cal ISO Operations

The Enron trading strategies and Enron's use of them to "game the system" are best understood in the specific context of Western energy markets. Thus, we provide a brief overview of the Cal PX's and Cal ISO's operations and trading rules.

The Cal ISO operates much of the transmission grid in California and is responsible for all real-time operations, such as continually balancing generation and load and managing congestion on the transmission system it controls. In California, a certified Scheduling Coordinator is the intermediary between the Cal ISO and the ultimate customer. Under California's restructuring legislation, the Cal PX was created primarily to operate two markets where energy was traded on an hourly basis. These were the day-ahead and day-of markets. These markets established a single clearing price for each hour across the entire Cal ISO control area, provided there were no transmission constraints. Where transmission congestion existed, a separate clearing price was established for each transmission constrained area or zone in California. Each individual zonal clearing price was based on adjustment bids submitted by buyers and sellers. The adjustment bids represented the value to an entity of increasing, or decreasing (*i.e.*, adjusting) its use of the system. In essence, this is a redispatch of the system to deal with congestion.

California's restructuring plan required the three California public utilities (Edison, San Diego, and PG&E) to sell all of their generation resources into the Cal PX and to buy all of their energy needs from the Cal PX. This made the Cal PX by far the largest Scheduling Coordinator in California, representing, at times, close to ninety percent of the load served by the Cal ISO grid. This requirement that the three public utilities exclusively use the Cal PX was critical in the restructuring program, since this was how the three public utilities were to calculate savings from using the new market structure and apply those savings to recover their stranded costs.

All Scheduling Coordinators (including, before it ceased operations in January 2001, the Cal PX) are required to submit a balanced schedule of load and generation to the Cal ISO for the following day. The Cal ISO then performs a security analysis to determine if the generation selected can serve customer demand without causing congestion on the transmission system. Although the rules were constantly being modified during 2000-2001, the basic steps of the day-ahead auction process were as follows:

7:00 a.m. The Cal PX conducts 24 hourly energy auctions for the following day.

9:00 a.m.	The unconstrained market-clearing prices (*i.e.*, a single price for all of California) become publicly available.
10:00 a.m.	The Cal PX (like all Scheduling Coordinators) submits to the Cal ISO the estimated load for the next day and the generating resources that will produce the energy necessary to serve that load.
11:00 a.m.	The Cal ISO either determines that the initial schedule is feasible (no congestion) using the available transmission facilities or requires that the schedule be modified by redispatch using adjustment bids..
12:00 p.m.	Modified schedules are submitted. At this time, the Cal ISO can automatically modify schedules to relieve any remaining congestion.
1:00 p.m.	The Cal ISO calculates the day-ahead charge for congestion on any congested paths.
3:00 p.m.	The Cal PX publishes zonal price information when there is transmission congestion in the day-ahead market. The zonal price differences are equal to the Cal ISO's hour-ahead congestion charges along the relevant paths.

The Cal ISO operates a variety of markets in order to procure the resources necessary to reliably operate the transmission system, including a day-ahead market and an hour-ahead market for relieving transmission congestion and an energy market to balance the system in real time. The Cal ISO's real-time market is the final energy market to clear chronologically, after all other markets in the region. Bilateral spot markets at trading hubs outside California generally operated in the time period between the close of the Cal PX market and the Cal ISO real-time market.

The interaction of the Cal PX and Cal ISO spot markets, together with the different market operations outside of California, is crucial to understanding, and analyzing the impact of, the various Enron trading strategies. The complexity of the California market rules, together with the existence of different rules for markets outside California, created an environment where Enron, and other entities, could readily create, utilize, and implement the various Enron trading strategies.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Staff concludes that the California experience highlights the need for standardized market rules throughout broad geographic regions. This fundamental market reform, combined with the ability of independent entities to administer and to monitor such larger markets, would eliminate much of the opportunity for an entity to create new means by which to "game the system."

2. Market Fundamentals and Critical Events in the West During the Summer of 2000

Not only is it necessary to understand California market operations as they existed during calendar year 2000, but it is also important to understand market fundamentals and critical events in the West, and particularly California, during the summer of 2000.[91] In the following list, Staff highlights some of these market fundamentals:

- By the summer of 2000, California had experienced economic growth that, together with unseasonably hot weather, created record high summer loads. During 2000, California was six percent hotter than the 30-year average.

- Generation and transmission expansion in California did not keep pace with such growth.

- Existing gas- and oil-fired generation in California experienced a high rate of forced outages due, in part, to increasing age and plant operation.

- Natural gas prices had doubled since the summer of 1999 and the cost of environmental credits for nitrogen oxide ("NOx") in the Los Angeles Basin rose to very high levels.

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[91] Much of the information in this section was taken from two reports about events in the West, and particularly in California during the summer of 2000. The first report is dated August 10, 2000, and was prepared by the Cal ISO. It is entitled *Report on California Energy Market Issues and Performance: May - June 2000*, and provides an overview of critical market events. The second report is dated November 1, 2000, and was prepared by the Cal PX. It is entitled *Price Movements in California Power Exchange Markets Analysis of Price activity: May - September 2000.*

- Net scheduled imports into California dropped due to low availability of hydroelectric resources from the Pacific Northwest, hot weather throughout the West, and an increase in generation exports out of California.

In the following list, Staff provides a chronology of critical market events in California during the summer of 2000:

- On May 22, 2000, prices in the Cal ISO's real-time market hit the $750/MWh purchase price cap for the first time as loads peaked at 39,532 MW.
- On May 22, 2000, the Cal ISO purchased over 9,100 MWh of energy out-of-market at an average price of $723/MWh. These purchases were from suppliers outside of the Cal ISO's control area and were necessary so that the Cal ISO could procure sufficient supply to meet the anticipated system peak load.

- Approximately 20-25 percent of total system energy needs were served by the Cal ISO's real-time energy market. This was caused by under-scheduling load in the Cal PX day-ahead market.

- During May 2000, average daily peak loads were 15 percent above the 1999 levels and peak loads grew by six percent.

- The three California public utilities were highly exposed to the volatility of the Cal PX spot market due to California Commission's policies and regulations which limited PG&E's and Edison's forward contracts. The presumption of prudence for purchases in the Cal PX spot market discouraged PG&E and Edison from using their full forward-contract allowances. For example, PG&E hedged between 1,100 and 1,800 MW in forward contracts out of the 3,000 MW allowed by the California Commission. Edison hedged approximately 1,700 MW of its 2,200 MW limit in June 2000, and between 3,000 to 3,500 MW of its 5,200 MW limit for July 2000 and August 2000.

- At least 34 percent of costs incurred by PG&E and Edison were paid, in effect, to themselves as a result of the requirement to sell and repurchase their own generation resources through the Cal PX.

- During high-load conditions in June 2000, scheduled net imports (imports less exports) into California were, on average, approximately 3,000 MW less than in

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

1999. The dispatch of imports in the real-time market partially offset this reduction in net scheduled imports.

B. The Enron Trading Strategies and Their Impact on Prices

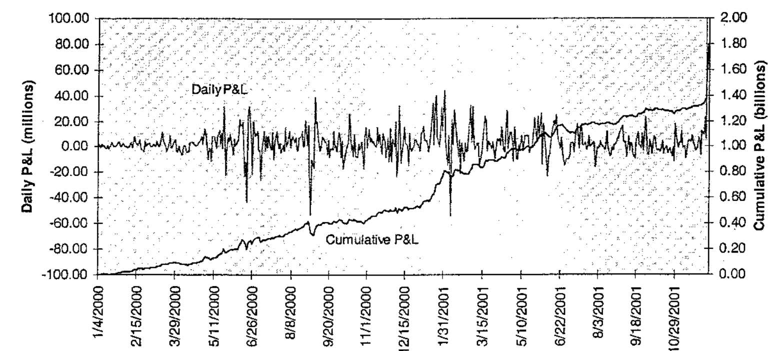
As stated earlier, quantifying the exact economic impact of the trading strategies is difficult because we have not identified a way to definitively associate particular transactions with particular strategies. However, Figure 11 places the impact of these strategies in context relative to Enron's total profits from the Western electricity trading for 2000-2001. According to raw data taken from Enron's databases, Enron experienced cumulative profits from electricity trades in the West in the neighborhood of $1.8 billion for 2000-2001 as shown by the intersection of the blue line at the right vertical axis. In addition, the daily profits and losses swing as much as $60 million and are often in the $5-$10 million range. While these data are unaudited, they indicate that it is highly unlikely that the impact of the Enron trading strategies on spot prices alone accounted for a substantial portion of Enron's total revenues from long-and short-term trades. For example, the total annual congestion revenues which Enron earned were about $60 million. Even if we assume that the annual congestion revenues were produced by some form of price manipulation, they equal only about three percent of the corporate revenues for these two years.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

We initially focused on "load shift" because, by Enron's own admission, this was an explicit attempt to manipulate prices.

The next set of trading strategies discussed include marketing power and energy within the rules in an effort to sell the product where it is needed the most. These strategies include various forms of exports and imports.

Figure 11: Daily and Cumulative P&L for the Western Electricity Trading Desk



The last set of trading strategies involve deceitful tactics such as providing false information or imaginary transactions.

1. Price Manipulation – Load Shift

As described in the May 8, 2002, data request, the trading strategy known as "load shift" involves a company submitting an artificial load schedule in order to receive inter-zonal congestion payments. This Enron trading strategy is particularly complicated and its success was dependent, in part, on the independent bidding behavior of other entities.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

By Enron's own admission, its use of this trading strategy was not very successful in that Enron was not able to move the price paid for congestion management because the bidding strategy of other entities had a counter-balancing effort. In any event, Enron may have received approximately more congestion revenues due to this trading strategy. Nevertheless, whether successful or not, "load shift" involves deliberately creating congestion on a transmission line to increase the value of Enron's transmission rights, and is clearly an attempt to manipulate prices.

As described in the Enron memoranda, this trading strategy involves creating the appearance of congestion by deliberately over-scheduling in one zone (*e.g.*, the southern zone) and under-scheduling by a corresponding amount in another zone (*e.g.*, the northern zone). For example, assume Enron's true load and resources were balanced by zone. Enron schedules an additional 100 MW of load in the southern zone and under-schedules by the same 100 MW in the northern zone. This inaccurate schedule requires 100 MW of additional north-to-south transmission relative to Enron's true loads and resources. By "shifting" load in this manner, Enron created congestion and potentially raised congestion prices. This benefitted Enron because it owned Firm Transmission Rights (FTRs) on the paths that it attempted to congest.

In late 1999, the Cal ISO held its first auction for FTRs covering the period February 1, 2000, to March 31, 2001. The FTRs equate to either physical or financial transmission rights along specific paths. By exercising its physical rights, the holder of an FTR has a priority to schedule use of the transmission path and thereby avoid congestion payments. To the extent that it does not exercise its physical rights, the holder of an FTR is entitled to share in the congestion revenues collected by the Cal ISO through the congestion markets.

In the Cal ISO's first annual FTR auction, Enron purchased 1,000 MW (62 percent) of the 1,621 MW in rights to north-to-south transmission on Path 26. The purchase of these FTRs cost Enron a total of $3.6 million. Path 26 is one of the two main transmission interfaces linking northern and southern California.[92] Enron's FTRs

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[92]It is useful to think of the California system as an "hour glass" figure with the two transmission paths connecting the northern and southern zones. During the winter, these paths constrain lower-cost generation in the south from reaching load in the north. Conversely, during the summer, these paths constrain lower-cost generation in the north (continued...)

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

entitled it to collect a significant portion of all congestion revenues on Path 26 that were due to north-to-south congestion, the typical direction of congestion during periods of peak demand in the summer. This gave Enron an incentive to try to create – through a "load shift" – north-to-south congestion over this transmission line. Enron sought to accomplish this through a "load shift." If Enron could shift load and thereby increase the congestion price, it would be paid the higher price for all 1000 MW of the FTRs

The vast majority of Enron's congestion revenues were from Path 26 during July and August 2000, and totaled approximately $33 million for those two months for that path alone. This amount represented a considerable profit above the $3.6 million that Enron paid for the Path 26 FTRs, even though, as explained below, it was not able to manipulate the prices of congestion payments.

Enron was generally not able to move the cost of congestion. This was due to the fact that two large market participants, Edison and PG&E, often set the price for congestion relief over a large band of load used for congestion relief. Figure 12 shows an aggregate congestion alleviation supply curve (the "inc/dec bid stack") for a typical hour in July 2000 in the day-ahead market. The market cleared on the large flat segment in the middle of the supply curve ranging from approximately 1,500-4,000 MW. This segment of the supply curve is formed by the combination of PG&E's bid to increase its load in the northern zone of $160/MWh and Edison's bid to decrease its load in the southern zone of $500/MWh. This results in a $330/MWh cost to redispatch the system in order to relieve the congestion and is the basis for congestion charges and payments. The market typically cleared in the large flat area in the middle of the supply curve.

As Figure 12 shows, Edison's and PG&E's large sizes made it difficult for Enron to increase the congestion prices above the $330/MWh level. Enron was able to profit by receiving congestion payments for its FTRs and may have increased its profits by artificially increasing congestion. However, it usually could not increase the congestion charge using this trading strategy. Nonetheless, the fake schedules that Enron submitted added unneeded confusion to the already complex congestion management program that the Cal ISO administered. In this manner, Enron harmed the market.

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[92](...continued)
from reaching load in the south.

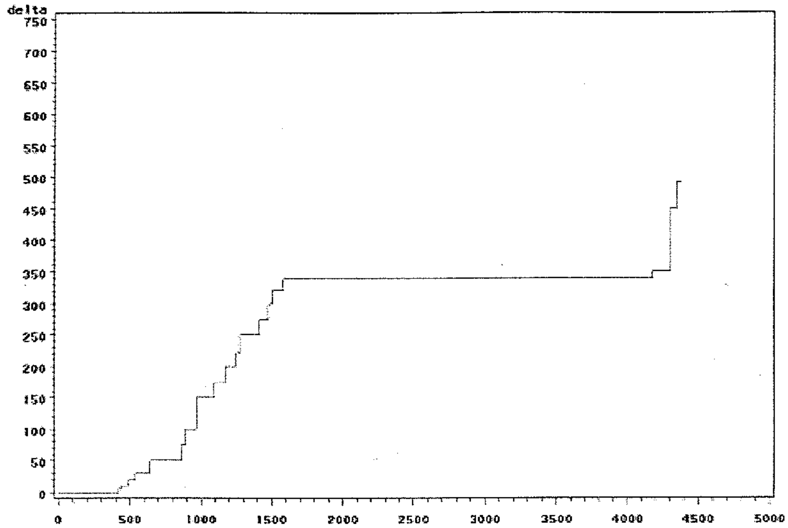

Figure 12: Congestion Price Curve (Prices vs. MWs of Congestion)

Staff's interpretations are corroborated by an December 1, 2000, report submitted to the Commission by the Cal ISO entitled, *The Firm Transmission Rights Market: Review of the First Nine Months of Operation, February 1, 2000 - October 31, 2000* (FTR Market Report).[93] The FTR Market Report was submitted as part of the Cal ISO's comprehensive congestion management redesign.

In the FTR Market Report, the Cal ISO states that it actively monitors the FTR market by tracking and analyzing the concentration of ownership and the scheduling behavior of entities with high concentrations. Enron's increased congestion revenues and its ownership of 62 percent of the FTRs on Path 26 led the Cal ISO to closely scrutinize

[93]This report was submitted pursuant to orders issued by the Commission on May 3, 1999 (87 FERC ¶ 61,582) and August 2, 1999 (88 FERC ¶ 61,524).

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Enron's scheduling behavior. The FTR Market Report noted that PG&E's under-scheduling of load in the Cal PX day-ahead market can cause or exacerbate north-to-south congestion on Path 26. The Report concludes:

> It is important to note that the [Cal ISO's] examination of bidding behavior has revealed that the primary FTR owners on Path 26 were not the entities causing these congestion and load scheduling patterns. Rather, these patterns are the result of behavior by other load serving entities. Thus the major FTR holders were the beneficiaries of usage charge revenues resulting from the cost minimizing bidding strategy of load serving entities in northern California.[[94]]

While Enron's "load shift" trading strategy by and large did not move the price paid to relieve congestion, Enron nevertheless attempted to raise the price of congestion by artificially scheduling load in the hopes that it could collect higher revenues. This trading strategy was defeated not by market rules or oversight, but rather by the actions of other companies that were under-scheduling load. Both of these behaviors would be prohibited by Staff's recommendation to prohibit submission of false information. Market rules should also be designed to economically discourage infeasible schedules.

2. Price Maximization – Exports

The following two trading strategies involve using exports and imports in some fashion to sell power where or when it is most valued.

a. Export of California Power

The trading strategy known as "export of California Power" involved buying energy at the Cal PX to export outside of California in order to take advantage of the price spread between the California market (which was capped) and the uncapped markets outside of California.

Fewer than a dozen entities either admitted to engaging in exports of California power or gave answers other than a denial. One hundred and twenty-five entities denied engaging in this trading strategy. However, given the increase in total exports from

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[94]FTR Market Report at 35.

California, as discussed below, and the narrative explanations provided in response to Staff's data requests, Staff concludes that this trading strategy was not properly or fully disclosed.

For example, the Commission's June 4, 2002, Show Cause Order in this proceeding requested that Portland provide a further explanation of its purchases from California and its resales of that energy outside of California. While admitting that such transactions did occur, Portland declined to identify the transactions, instead referring the Commission to a mass of previously-submitted data without further explanation. In its response to the Show Cause Order, Portland provided all transaction data during the period and stated:

> Given Portland's portfolio management of its resources, Portland knows of no valid methodology to match the California ISO and PX purchases with any particular resale outside of California . . . . This information should allow the Commission to evaluate the impact of the purchases of power that Portland made from the ISO and PX during Price Cap Hours.[95]

Portland's assertion that there is no "valid methodology" for linking purchases with resales is specious. On January 31, 2002, Staff submitted a report to Congress on the economic impact on Western utilities and ratepayers associated with price caps on daily spot market power sales. These daily spot market transactions involved the resale of energy purchased under long-term forward power contracts when such energy became surplus to system needs. In preparing this earlier report, Staff requested that Western utilities, including Portland, provide actual cost and transaction data for both the original cost of the long-term purchases and the revenues generated by reselling the surplus energy for each transaction. Portland supplied that information to Staff. Now, Portland does not explain why it cannot identify exports from California. Even with a portfolio of resources, whenever Portland purchases more power in California than its load in California, it is engaged in an export of California power. Even if Portland had load in California, it is a simple calculation to determine what is an export.

In narrative responses to the May 8 data request, various market participants argue that some of the Enron trading strategies, such as exports of California power, are examples of economically rational behavior, or legitimate arbitrage. They note that the

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[95]Response of Portland, dated June 14, 2002, at 1-2.

Cal PX, Cal ISO, and the Commission have never implemented market rules prohibiting the export of energy from California to locations outside the state. Respondents maintain that exporting power outside of California in order to reach other market opportunities, or to take advantage of a price spread, is good business practice. They argue that, from an individual entity's perspective, an export may have provided an optimal business opportunity.

For example, some respondents state that California generators may have wanted to make a long-term sale to avoid being entirely exposed to the California spot markets. Staff notes that, under California's restructuring plan, the three California public utilities were required to buy their energy in the spot market. This created an incentive for entities with in-state generation who desired to enter into forward sales to seek markets outside of California. Also, they simply may have exported sport sales to avoid the price cap in California.

While it may be true that any individual company may have acted in an economically rational manner by exporting its power to a market with higher prices, collectively the large amount of exports contributed to the scarcity in California during 2000-2001.

Historically, California has relied heavily on generation imports to meet its peak summer needs. However, the summer of 2000 did not follow this pattern. In fact, when compared to earlier periods, the total amount of power exported out of California during that summer was significantly larger than expected. This anomaly has been the subject of prior reports and studies. For example, a report by the General Accounting Office (GAO) on California restructuring indicated that monthly exports from May through October 2000 were between 40 and 230 percent higher than the same months in 1998 and 1999. Overall, exports were approximately 200 percent higher from May through October 2000 than in the same period in either 1998 or 1999.[96]

Table 1 compares import and export data from June through September 2000 with import and export data from the same months in 1999. Total imports are lower in 2000,

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[96]U.S. General Accounting Office, *Restructured Electricity Markets: California Market Design Enabled Exercise of Market Power*, Report No. GAO-02-828 (released July 2002), at page 32 (GAO California restructuring report).

while total exports are higher. As a result, total net imports were much lower in 2000 than in 1999.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Table 1: Hourly Average Peak Imports

		Hour-ahead schedules (MW)[1]		
Year	Month	Scheduled Imports	Scheduled Exports	Net Scheduled Imports
1999	June	8,190	1,993	6,197
	July	9,370	2,845	6,525
	August	9,074	2,782	6,292
	September	9,247	2,106	7,141
2000	June	7,001	3,852	3,149
	July	7,574	4,918	2,656
	August	6,884	5,809	1,074
	September	6,809	3,974	2,836
[1] Based on ISO hour-ahead schedules.				
Peak hours are Monday-Saturday, hours ending 7-22.				

Net imports for 2000 decline through August, which correlates with the Cal ISO's lowering of its purchase price caps. On July 1, 2000, the Cal ISO lowered the price cap from $750/MWh to $500/MWh. On August 7, 2000, it again lowered the price cap, this time down to $250/MWh.

The hour-ahead scheduled imports into California halved from the summer of 1999 to the summer of 2000. This dramatic decline of imports was partially offset by an increase in imports in the Cal ISO real-time market. Staff concludes that the lack of uniform price caps throughout the West encouraged utilities to sell available generation on a day-ahead or hour-ahead basis outside of California. This pattern increased through the summer as the cap was lowered until September when the peak demands declined.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

These facts underscore the critical need for uniform wholesale pricing rules throughout a regional market, particularly in times of scarcity.

California deregulated its retail electric market and generation assets were sold by the three California public utilities to other entities that did not have franchised service areas or an obligation to serve particular customers. At the time, this was a unique retail market structure in the West. The differences in retail markets structures, including the mandated reliance on the spot market in California, contributed to the regional market problems. A merchant generator seeking a better price or desiring to sell in forward rather than spot markets is behaving in a rational economic manner. Existing vertically-integrated utilities in neighboring states still had an obligation to serve their native load from their own generation resources. When it was economical, these utilities also bought generation from California to serve their load or for resale in other Western markets, whichever was most valuable.

Staff concludes that the export trading strategy was largely the result of asymmetrical market rules within which products were sold where they brought the highest price.

b. "Ricochet" or "Megawatt Laundering"

The trading strategy known as "ricochet" or "megawatt laundering" involved one entity buying energy from the Cal PX in the day-ahead market and exporting it to a second entity, which received a fee from the first company. The energy is later resold back to the Cal ISO in the real-time market (or as an out-of-market sale).[97] Several respondents provided examples of this trading strategy.

Koch Energy Trading Inc. (KET), one of the predecessors in interest to Entergy-Koch Trading, LP, exported a total of 1,925 MWh from California to the southwest, from where it was subsequently imported into California. These transactions occurred on three days (May 22, June 5, and June 28, 2000) and used a series of agreements with Public Service Company of New Mexico (PNM). A critical service that PNM provided

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[97]If there were insufficient bids in the Cal ISO's real-time market, the Cal ISO, as a last resort to procure the resources necessary to operate the system, would purchase energy out of its market. These out-of-market resources were paid their bid, but did not affect the market-clearing price paid to other generators.

was a Parking Service (pursuant to the Western Systems Power Pool Agreement) that PNM admitted engaging in as part of its response to Staff's data request. Under this service, PNM buys energy from an entity in a day-ahead or other forward market and resells the energy back to the original entity in the real-time market where it is ultimately sold. This service is necessary for the export leg of the transaction because under North American Reliability Council (NERC) rules, the energy must be scheduled and identified to serve a load. Entities such as power marketers therefore must rely on a utility that operates a control area (and thus that always have a load to serve), such as PNM, to complete the first part of this transaction.

Eugene Water & Electric Board (Eugene) had a similar Parking Service Agreement with Sempra Energy Trading Corp. (SETC) for the period March 7, 2001, through February 28, 2002. Under this agreement, SETC sold up to 50 MW of on-peak energy to Eugene, which in turn sold a like amount of energy back to SETC in real-time. TransAlta Energy Marketing (TransAlta) identified a small volume of trades that fit this category. TransAlta explains that market window timelines in the Cal PX forced participants to commit to energy purchased for exports before spot markets in the Northwest began trading. In certain cases when the energy was not resold in the Northwest markets, the energy was resold to the Cal ISO.

The Enron memoranda indicate that Enron included the generation of other sellers, such as Powerex and Puget Sound Energy, Inc. (Puget) when employing this trading strategy.[98]

"Ricochets" necessarily involve multiple entities, and the responses to Staff's data requests indicate that there was an abundance of willing counter-parties. Because both generation and transmission were required, Enron needed others to move power into and out of the Cal ISO's system. Interestingly, most of the transmission facilities critical for these trading strategies that are directly connected to the Cal ISO's system are owned or controlled by non-public utility California municipals including the Transmission Agency of Northern California (TANC) and the City of Los Angeles Department and Water and Power (LADWP).

[98]Both of these entities denied any knowledge of this. However, Puget states that during the first few days of December 2000, Puget was specifically requested by the Cal ISO to submit a schedule as if a Puget load existed in California.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

In addition to California transmission systems not operated by the Cal ISO, Enron also relied on transmission systems in the Pacific Northwest, specifically, those of Bonneville Power Administration (BPA), Avista, and Enron's public utility affiliate, Portland. Transcripts of Portland traders and transmission personnel include detailed instructions by Enron personnel on how the various participants (Portland and Avista) were to record transactions and how to report the various parts of the transactions consistent with NERC requirements and the Commission's regulations.

Entities routinely engage in trying to capture profits from price differences that exist between different time periods, *e.g.*, purchasing power day-ahead and selling it in real time. The actual price in the real-time market can be higher or lower than the original price paid in the day-ahead market. Entities assume this arbitrage risk where others are unwilling to do so.

During the two-year review period, this trading strategy could also be used to avoid the price caps that were set in the Cal ISO real-time market. This is because the Cal ISO also bought power "out-of-market" at the last minute when there was insufficient supply bid into its market. These out-of-market purchases were typically priced above the price cap. Suppliers knew that the Cal ISO would pay any price in an effort to avoid blackouts. This behavior (raising prices at the last minute where buyers are unable or incapable of saying no) was not legitimate arbitrage, but was an exercise of market power.

Staff recommends that until uniform market rules and demand response are in place in California, the Commission continue to apply mitigation measures.

3. Trading Strategies Based on False Information

The following trading strategies are all premised on submitting false information schedules. One trading strategy, "fat boy," was designed to offset the bidding strategies of the California public utilities. All these strategies were premised on inaccurate load data. The other trading strategies are all attempts to fabricate transactions for profit. Staff is evaluating whether these trading strategies violated the Cal ISO's tariff because they involved submitting false schedules.

a. "Fat Boy" (or "Inc-ing Load")

The trading strategy known as "fat boy" involved a Scheduling Coordinator, such as Enron, artificially increasing ("inc-ing") load on the schedule it submits to the Cal ISO to correspond with the amount of generation in its schedule. Under California market rules, all schedules submitted to the Cal ISO had to be balanced (*i.e.*, load and generation had to be equal). The company then dispatched the generation it scheduled, which was in excess of its actual load. This resulted in the Cal ISO paying the company for the excess generation at the clearing price established in the real-time market.

Staff emphasizes that this trading strategy was conceived and used in response to the procurement strategy used by the three California public utilities, which itself was a response to the unintentional interplay of Cal PX and Cal ISO market rules. The Cal PX, like all Scheduling Coordinators, was required to send the Cal ISO a schedule that balanced an equal amount of generation and load. The Cal PX day-ahead market cleared before the Cal ISO market, which was capped at various levels (depending on the date). Under the original California restructuring program, the three California public utilities were required to exclusively use the Cal PX for scheduling and purchasing. All of their generation resources were bid (sold) into the spot market. The three California public utilities also submitted bids into the Cal PX spot market to buy generation to serve their retail load.[99]

In an effort to minimize their procurement costs under these market rules, the three California public utilities, especially PG&E, habitually under-scheduled their load in the Cal PX market. In other words, they would only buy energy in the Cal PX market that was priced at or below the capped Cal ISO real-time market, relying on the fact that residual load could then be supplied in the Cal ISO real-time market at capped prices. PG&E's strategy involved a deliberate attempt to push the Cal PX price below the capped price in the Cal ISO real-time market.

While this procurement strategy allowed the public utilities to minimize their costs, under-scheduling caused chronic operational and reliability problems for the Cal ISO that were documented in numerous filings with the Commission. The Cal ISO's real-time market was designed to supply only the small amount of energy (less than five percent) needed to constantly balance generation with actual load. Chronic under-

[99]In the December 15 Order, the Commission ordered a halt to the practice of near-total reliance on the spot market in an effort to allow the three California public utilities to procure a more balanced portfolio.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

scheduling in the Cal PX day-ahead market transformed this "balancing "market into an energy commodity market that served far more load than it was designed to supply. The uncertainty of not knowing how to supply a much larger percentage of the load until real-time caused considerable reliability problems for the Cal ISO. In short, the three public utilities were using the real-time market for a purpose for which it was not intended.

The "fat boy" trading strategy, in turn, was a response to this under-scheduling problem. Under California market rules, all Scheduling Coordinators (*e.g.*, Cal PX and others, such as Enron) were required to submit to the Cal ISO day-ahead schedules that were balanced. The "fat boy" trading strategy was a way to preschedule on a day-ahead basis an imbalance sale in the Cal ISO's real-time market. While neither under-scheduling nor "inc-ing load" was an intentional part of California restructuring, it is clear to Staff that under-scheduling was of far greater concern to the Cal ISO, no doubt because under-scheduling directly led to reliability problems. Indeed, some of the respondents informed Staff that the Cal ISO actually helped them to engage in the "fat boy" trading strategy by providing them with artificial or simulated load and delivery points. For example, an entity with only generation and no load could not submit a balanced schedule to the Cal ISO. According to Reliant, the Cal ISO created an artificial load point which enabled it to submit a balanced schedule to the Cal ISO.

Enron's use of the "fat boy" trading strategy did not set the market-clearing price in the Cal ISO's real-time market. Under California market rules, entities are price takers for the amount of generation in excess of actual load; that is, they are paid the clearing price that was established in the Cal ISO market. Nevertheless, the submission of false schedules, and the Cal ISO's encouragement of such fabrications to circumvent the balanced schedule rule, would be prohibited under Staff's recommendations that all tariffs for market-based rates include a prohibition against submitting false information. Market rules should be amended, not circumvented.

b. "Non-Firm Exports," "Death Star," and "Wheel Out"

In this section, we examine three Enron trading strategies known as "non-firm exports," "death star," and "wheel out," and similar variations.[100] All are designed to

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[100]Related schemes that are referenced in documents other than the Enron memoranda include "black widow," "red congo," and the "Forney perpetual loop." *See* (continued...)

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

generate payments for relieving transmission congestion by "fooling" the Cal ISO's computerized congestion management program. These trading strategies generally involve scheduling transmission in the opposite direction of congestion, and thereby getting paid for the counterflow. They are all premised on imaginary transactions that are nonetheless eligible for congestion payments from the Cal ISO.

As described in the May 8, 2002, data request, in "death star," a 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 trading strategy has been the subject of hearings in California.[101] In a "wheel out," a company, knowing that an intertie is completely constrained (that is, its available capacity is set as zero), or that line is out of service, schedules a transmission flow over the facility, knowing that the schedule will be cut and it will receive a congestion payment without actually sending energy over the facility. In a "non-firm export," a company gets a counterflow 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.

Staff notes that to the extent these trading strategies involve in part or in whole non–firm exports, the Cal ISO issued a market notice in early August 2000 prohibiting such activities.

The first known instance of these trading strategies occurred on May 25, 1999.[102] On that day, Enron scheduled an infeasible transaction in the Cal PX market across an intertie between Southern California and Nevada. Because this schedule called for 2,900 MW to go across a line with only 15 MW of available capacity, it triggered the Cal ISO's congestion management procedures. A later investigation by the Cal PX into this incident resulted in a cash settlement by Enron.

However, according to the Enron memoranda, these trading strategies became more complex and included the participation of other entities. The counter-parties were

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[100](...continued)
June 5, 2002, McCullough Research report.

[101]*Id.*

[102]*Id.*

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

used primarily to schedule parts of the transactions or to use transmission facilities outside the Cal ISO's control area in order to hide the transaction.

In order to carry out these trading strategies, Enron used a variety of counter-parties, most prominently, Portland (its affiliate), El Paso Electric, and Avista. An example of one of the circular schemes, "the Forney perpetual loop," follows:

1. Enron schedules a non-firm energy export from Palo Verde in Arizona, through California, and across the Oregon Border (Border);

2. Avista buys the energy from Enron and then sells the energy to Portland at the Border;

3. The energy is transferred across Portland's system;

4. Enron then returns the energy to the Border;

5. LADWP schedules the energy from the Border to Palo Verde in Arizona; and

6. Finally, the energy is scheduled to returned to California.

In fact, no energy flows because the schedule begins and ends at the same location. Non-public utility California utilities, such as the Northern California Power Agency and LADWP, were also particularly crucial because they own and control transmission facilities that interconnect with the Cal ISO's system, but which are outside the control of the Cal ISO. This was crucial to helping avoid detection.

Staff notes that in its response to the May 8, 2002, data request, Powerex states that there is a structural flaw in the Cal ISO's congestion management software that prevents the software from recognizing that a tie is out of service. Powerex claims that it has a standing practice of maintaining adjustment bids at interties to relieve congestion. The Cal ISO occasionally requested Powerex to remove its adjustment bids when the ISO intended to take the line out of service. However, if the Cal ISO did not provide such advance notice, Powerex would receive a congestion payment. Powerex states that it is unable to identify such payments.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

In addition, TransAlta described several transactions that have certain operational elements that are common to these Enron trading strategies. But, unlike the Enron trading strategies, the TransAlta transactions actually moved power. For example, what TransAlta calls "re-circulation" was a way to move energy supply from southern California to northern California when the Cal ISO-controlled transmission path between these regions was fully subscribed. TransAlta would move the energy to the northwest using its transmission rights over non-Cal ISO facilities and then import the power into northern California. At times, the Cal ISO actively sought the assistance of TransAlta in implementing these energy transfers.

These trading strategies would not be possible if a single comprehensive congestion management system is implemented in the West as Staff recommends. In addition, artificial congestion or congestion relief would violate Staff's recommended tariff language prohibiting false schedules and information.

c. "Get Shorty"

As described in the May 8, 2002, data request, the "get shorty" trading strategy involves the "paper trading" of ancillary services. Ancillary services include various types of generation capacity that are held in reserve for use in a contingency situation such as the loss of a critical generation or transmission facility. These services are required by the Cal ISO (and all other transmission providers) in order to reliably operate its system and to meet various operational standards.

In this trading strategy, Enron would commit to provide the ancillary services in the Cal PX's day-ahead market and then cover its position by purchasing those services in the Cal ISO's hour-ahead market. There is a legitimate profit motive here: to sell high in the day-ahead market and buy back at a lower price in the real-time market. Staff notes that Cal ISO Tariff Amendment No. 4, which the Commission accepted for filing,[103] permits the "buy back" of ancillary services as a legitimate form of arbitrage.

However, one of the Enron memoranda indicates that its traders committed to sell ancillary services without actually having the ancillary services on standby (which is why the trading strategy is also called "paper trading"). Because entities are required to

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[103]California Independent System Operator Corporation, 82 FERC ¶ 61,327 (1998).

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

identify the source of the ancillary services (that is, the specific generating unit), Enron's traders submitted false information to the Cal ISO. It is this aspect of the trading strategy – the deliberate submission of false information to the Cal ISO – that distinguishes it from permissible arbitrage activity.

Staff notes that the Cal ISO actively audits schedules with actual meter data in order to verify the availability of resources for providing ancillary services. Absent discovery during the Cal ISO audit procedures, it is difficult to quantify the economic effect of this trading strategy. To the extent this trading strategy involves deliberately supplying false information, the practice should also be prohibited. No respondent other than Enron admitted to submitting false information or "paper trading" ancillary services.

d. Selling Non-Firm Energy as Firm Energy

In this trading strategy, a company deliberately sells or resells what is actually non-firm energy to the Cal PX, while claiming that it is firm energy.

NERC prohibits this practice since it violates NERC's existing interchange rules. However, the Enron memoranda attempt to justify this trading strategy on the grounds that it supposedly brought additional supply to California, with no apparent impact on Cal PX energy prices. The Enron memoranda also explain that Enron was subject to financial risk because, if the non-firm energy supply were cut, Enron would have to cover its position by purchasing that energy in the Cal ISO's real-time market as a price taker.

Staff finds this rationalization to be particularly troubling because Enron attempted to legitimize deception, the deliberate submission of false information, and actions that NERC expressly prohibited. This is a key example of why Staff is recommending an explicit prohibition against providing false information.

This trading strategy also compromises reliability because non-firm-energy is not backed up with reserve generation by the supplying party. This problem is made worse when non-firm energy is imported into another control area. The receiving control area will not procure reserves for the import, under the illusion that the supplying party is responsible for supplying adequate generation reserves.

Because this Enron trading strategy usually involves a purchase, it is difficult to detect absent the reporting of the entity selling the non-firm energy to Enron. On one

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

occasion, Enron purchased non-firm energy from an Arizona utility and resold the energy to the Cal ISO. After the energy was cut, the Arizona utility notified the Cal ISO of the Enron resale. However, after the fact, the Cal ISO had no means of penalizing Enron for its actions other than to charge Enron for imbalance energy. The trading strategy would also be unlawful under Staff's recommended tariff provision prohibiting the submission of false information, including false schedules.

The remaining trading strategies were difficult to orchestrate because of the many complicated arrangements required and the involvement of so many parties. Therefore, time and resources made these trading strategies impractical. To the extent these trading strategies were executed during the Refund Period, such transactions, like all spot market transactions, will be mitigated.

In conclusion, this initial report evaluated the Enron trading strategies' effect on spot prices. Staff will continue to investigate whether the effort put into these spot market strategies influenced prices for long-term physical or financial products. In addition, to the extent that these trading strategies may have violated Federal criminal or civil statutes, Staff will recommend that the Commission forward all relevant data to the Department of Justice, the CFTC, and the SEC for their respective review and disposition. Staff has cooperated and continues to cooperate with their inquiries.

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

Glossary of Terms and Acronyms

Terms	Description
Bcf	Billion cubic (feet of gas).
Bid	A motion to buy a commodity or a futures or options contract at a specified price. Opposite of offer.
Bid-week price	A bid-week price is the volume-weighted measure of gas prices for the following month done during the pipeline nomination period. Generally, a bid-week begins five working days prior to the last trading day of the month, although it can vary across regions of the country.
Btu	British thermal unit: the amount of heat required to increase the temperature of one pound of water one degree Fahrenheit. A Btu is used as a common measure of heating value for different fuels, since it allows the price for different fuels to be easily compared when expressed in $/million Btu.
Cal ISO	California Independent System Operator Corporation: the transmission provider regulated by the Commission that oversees and operates much of the transmission grid in California.
Cal PX	California Power Exchange Corporation, on which much of wholesale electricity, primarily in the spot market, was formerly traded in California.

CFTC	Commodity Futures Trading Commission: the federal agency that administers the Commodity Exchange Act and regulates futures trading in commodities on organized exchanges.
City gate	The location at which gas changes ownership or transportation responsibility from a pipeline to a local distribution company or gas utility.
Correlation coefficient	The correlation coefficient (r) measures the strength of the linear relationship between two variables. A value of $r > 0$ indicates a positive linear relationship; a value of $r < 0$ indicates a negative linear relationship. The correlation coefficient can range from -1 to 1 with 1 meaning perfect correlation; 0 meaning no correlation; and -1 meaning perfect negative correlation.
Derivative	A financial instrument the price for which is dependent on, or derived from, an underlying product, such as a cash market commodity, a futures contract or other financial instrument, securities, equity indices, debt instruments, or any agreed upon price index. Derivatives can be traded on regulated exchanges or over-the-counter. Futures contracts are derivatives of physical commodities, options on futures are derivatives of futures contracts. Derivatives involve the trading of rights or obligations based on the underlying product, but do not directly transfer property. They can be used to hedge risk or to exchange a floating rate of return for a fixed rate of return.
EOL	Enron OnLine: Enron's former electronic trading platform, used for trading of physical

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

	and derivative products, including natural gas and electricity. EOL represented that it was a one-to-many trading platform, with an Enron affiliate always one (and sometimes both) of the parties to a transaction conducted on EOL. In contrast, on a many-to-many trading platform, any trading entity may post bids and offers. NYMEX uses "many-to-many" trading.
Forward contract	A supply contract between a buyer and a seller, in which the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of a commodity on a specified future date. Payment in full is due at the time of, or following delivery. This differs from a futures contract where settlement is made daily, resulting in partial payment over the life of the contract. A forward contract refers to non-exchange trading of commodities. The price in a forward contract may be agreed upon in advance, or there may be agreement that the price will be determined at the time of delivery.
Futures contract	A futures contract is an agreement to purchase or to sell a commodity for delivery in the future: (1) at a price that is determined at initiation of the contract; (2) which obligates each party to the contract to fulfill the contract at a specified price; (3) which is used to assume or shift price risk; and (4) which may be satisfied by delivery or offset.
Hedging	Taking a position in a futures or forwards market opposite to the position held in a cash market to minimize the risk of financial loss from an adverse price change; a purchase or sale of futures or forwards as a temporary

	substitute for a cash transaction that will occur later.
Henry Hub	A pipeline interchange, located in Vermillion Parish, Louisiana, which serves as the delivery point of natural gas futures contracts. It is one of the main entry points for Gulf production and can direct gas to a variety of market areas, including the Midwest, Southeast, and Northeast. It is the largest natural gas pooling point in the world, handling about 1 Bcf/day of physical flows. The two compressor stations that serve the hub can handle 1.9 Bcf/day. An average of 5 Bcf of gas is traded daily at the hub. The physical configuration of the system, coupled with the fact that there is little in the way of constraints (congestion) in and out of the hub, creates a very liquid market.
kWh	A kilowatt hour. One thousand watts used for one hour, or the amount of electricity needed to light ten 100-watt light bulbs for a one-hour period.
Liquidity	A market is said to be "liquid" when it has a high level of trading activity.
LDC	A local distribution company: a utility that distributes natural gas primarily to end-users.
Mark-to-market	Daily cash flow system used by U.S. futures exchanges to maintain a minimum level of margin equity for a given futures or options contract position by calculating the gain or loss in each contract position resulting from changes in the price of the futures or options contract at the end of each trading day.

Many-to-many trading	In many-to-many trading, any trading entity may post bids and offers. In contrast, in one-to-many trading, only one entity posts bids and offers, and one entity (or one of its affiliates) is always at least one side to a transaction. NYMEX uses many-to-many trading.
Mcf	One thousand cubic feet (of gas).
MMBtu	One million British thermal units, equal to one dekatherm. Approximately equal to a thousand cubic feet (1 Mcf) of gas.
MWh	A megawatt hour. One million watts used for one hour, or the amount of electricity needed to light 10,000 100-watt light bulbs for a one-hour period.
NYMEX	New York Mercantile Exchange: a organized exchange regulated by the CFTC. NYMEX is a self-regulatory organization which must enforce minimum financial and reporting requirements on its members, among other responsibilities outlined in the CFTC's regulations.
Trading	Buying and selling.
Offer	A motion to sell a commodity or a futures or options contract at a specified price. Opposite of bid.
One-to-many trading	In one-to-many trading, one entity posts or makes all bids and offers, and one entity (or one of its affiliates) is always on at least one side of each transaction. In contrast, many-to-many trading allows any trading entity to post bids and offers. NYMEX uses many-to-many

	trading, while EOL represented that it used one-to-many trading.
Options	A contract which gives the holder the right, but not the obligation, to purchase or to sell the underlying futures contract at a specified price within a specified period of time in exchange for a one-time premium payment. The contract also obligates the writer, who receives the premium, to meet those obligations.
OTC	Over-the-counter: a term referring to derivative transactions that are conducted other than on regulated exchanges. OTC transactions may be conducted through brokers or principal-to-principal on either an electronic trading platform (such as EOL) or the telephone.
Power marketer	A public utility company that has authority from the Federal Energy Regulatory Commission to sell wholesale electricity and/or ancillary services at market-based rates.
Price index	An index, or average, which may be weighted, of selected prices, intended to be representative of the markets in general or a specific subset of prices.
SEC	Securities and Exchange Commission: the federal agency that administers federal securities laws and regulates firms that buy and sell those securities.
Spot market	Generally, a market for immediate delivery of a physical commodity. For the purposes of this report, "spot market" sales are "sales that are 24 hours or less and that are entered into the day of

20020813-0468 Received by FERC OSEC 08/13/2002 in Docket#: PA02-2-000

	or day prior to delivery." 95 FERC ¶ 61,418 at 62,545, n. 3.
Spot price	The price at which a physical commodity for immediate delivery is selling at a given time and place.
Underlying commodity	The commodity or futures contracts on which a commodity option is based, and which must be accepted or delivered if the option is exercised. Also, the cash commodity underlying a futures contract.
Wash trades	Transactions that give the appearance of sales and purchases, but which are initiated without the intent to make a bona fide transaction and which generally do not result in any actual change in ownership or the trader's market position. Wash trades that are entered into with the intent to reduce or eliminate market risk, but without the intent to establish a market position, may be illegal. Thus, a purchase and a sale entered simultaneously or nearly simultaneously with instructions to execute at or near the same price could be an illegal wash trade.

Williams Traders Gave False Data

By Chip Cummins

Williams Cos. said its traders provided inaccurate information to a publisher of natural-gas price indexes, widening the latest controversy enveloping wholesale energy markets.

The disclosure comes at a particularly bad time for the Tulsa, Okla., energy concern, which is trying to sell its energy-trading portfolio. By providing inaccurate information for indexes, there is the possibility that traders could manipulate market prices and artificially inflate the value of their company's portfolio.

Earlier this month, Dynegy Inc. of Houston, and American Electric Power Co. of Columbus, Ohio, fired a handful of traders who allegedly provided bad data to index publishers. The three companies have said they haven't been able to ascertain whether the inaccurate information affected the indexes or market prices. A Williams spokesman said the company doesn't believe the value of its trading portfolio has been affected.

The indexes, compiled and published by a handful of independent companies, are widely used to set prices for gas supply contracts between producers and users. Traders would have the opportunity to boost profits if they provided false data—such as transaction prices and volumes—to artificially move markets in favor of their own trading positions.

Companies often use market prices to help value the longer-term contracts in their portfolios. Those valuations are already under scrutiny from analysts and investors because they rely in large measure on a company's own, proprietary formulas. If inaccurate information provided to index publishers affected market prices, portfolios could become even more suspect.

Last week, Williams delayed the release of its quarterly earnings, citing "active" discussions over the sale of its trading portfolio and other assets. In 4 p.m. New York Stock Exchange composite trading Friday, Williams was down seven cents, or 4.8%, at $1.40.

Williams said previously that an extensive examination of its gas business hadn't uncovered any instances of traders providing bad information to index publishers.

Kelly Swan, the Williams spokesman, said Friday the inaccuracies came to light only last week after an expanded internal investigation. He said a "limited" number of traders were involved.

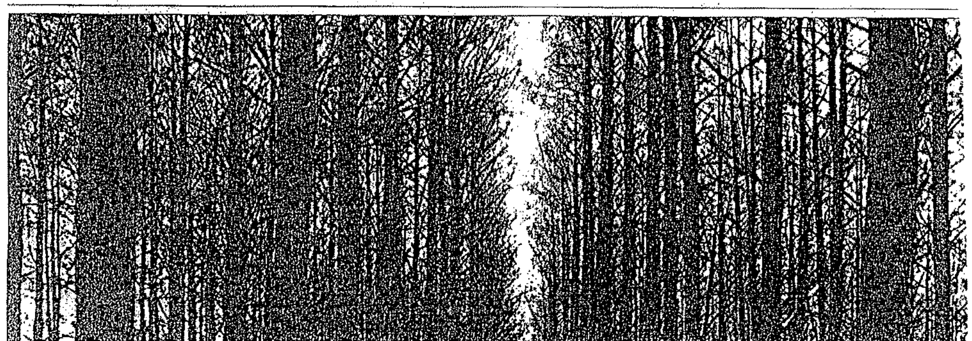
The company hasn't determined whether disciplinary action is warranted, but if the inaccurate information was provided knowingly and willfully, the company said it would be a clear violation of its policy. "Our people are supposed to be honest," Mr. Swan said.

The Commodity Futures and Trading Commission has taken the lead in investigating whether price indexes were manipulated by a number of energy companies. Several other federal agencies, including the Securities and Exchange Commission and the Federal Energy Regulatory Commission, are conducting a wider-ranging probe of energy trading.

Williams said it informed the CFTC and other agencies about its discovery and is cooperating with those agencies' investigations.

Separately, Western Gas Resources Inc. of Denver said it sued Williams in a dispute over control and ownership of approximately one million acres of gas-producing properties in Wyoming. The properties are part of Williams's oil and gas assets that served as collateral for a $900 million loan from Lehman Brothers Holding Inc. and Warren Buffett's Berkshire Hathaway Inc.

Mr. Swan, the Williams spokesman, said the suit is without merit and won't affect the terms of the loan, which helped the company stave off bankruptcy in late July. Representatives at Lehman Bros. and Berkshire Hathaway weren't immediately available for comment.



Committee on Governmental Affairs
EXHIBIT #A-33a

Committee on Governmental Affairs
EXHIBIT #A-33b

AEP DISMISSES FIVE FOR PROVIDING INACCURATE MARKET DATA FOR INDEXES

COLUMBUS, Ohio, Oct. 9, 2002 - American Electric Power (NYSE: AEP) dismissed five employees involved in natural gas marketing and trading after the company determined that they provided inaccurate price information for use in indexes compiled and published by trade publications.

The company discovered the inaccuracies during an internal review of its trading activities. The market indexes published by trade publications are compiled using trade data voluntarily provided by a variety of industry sources. The company cannot determine if the inaccurate data had any impact on the published indexes.

Prior to learning about the reporting of inaccurate data, AEP had instituted measures to require that all price information provided for use in market indexes be verified and reported by the office of AEP's chief risk officer.

"We did not approve and we do not condone this sort of activity," said Eric van der Walde, executive vice president - AEP Energy Services. "We are serious about ethical business practices and took action immediately after discovering this activity."

American Electric Power is a multinational energy company with a balanced portfolio of energy assets. AEP, the United States' largest electricity generator, owns and operates more than 42,000 megawatts of generating capacity in the U.S. and select international markets. AEP is a leading wholesale energy marketer, ranking among North America's top providers of wholesale power and natural gas with a growing wholesale presence in European markets. In addition to electricity generation, AEP owns and operates natural gas pipeline systems, natural gas storage, coal mines, and the fourth-largest inland barge company in the U.S. AEP is also one of the largest electric utilities in the United States, with almost 5 million customers linked to AEP's wires. The company is based in Columbus, Ohio.

Pat D. Hemlepp
Director, Corporate Media Relations
American Electric Power
614/223-1620

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Committee on Governmental Affairs
EXHIBIT #A-33c

(BW)(TX-DYNEGY)(DYN) Dynegy Dismisses Six Employees, Will Discipline Seven Others for Violations of Company Policies

DYNEGY

Business/Energy Editors

HOUSTON--(BUSINESS WIRE)--Oct. 18, 2002--Dynegy Inc. (NYSE:DYN) today dismissed six employees and will discipline seven others in its natural gas trading business for violations of company policies. The violations were related to Dynegy's previously disclosed finding that employees in its marketing and trading business provided inaccurate information regarding natural gas trades to various energy industry publications that compile and report index prices. The disciplinary actions were taken as a result of an ongoing investigation conducted by the Audit and Compliance committee of Dynegy's Board of Directors and in collaboration with independent counsel.

"Our Code of Business Conduct represents a commitment from all employees that they will conduct themselves in an ethical and responsible manner," said Dan Dienstbier, chairman and interim chief executive officer of Dynegy Inc. "It is our practice to investigate any possible violation fully and take the appropriate corrective actions to maintain the integrity of our workplace."

Dynegy discovered the inaccuracies during an internal review of its trading activities, which is being conducted as part of an ongoing Commodity Futures Trading Commission investigation. In connection with the investigation, the company also has relieved a corporate compliance officer of his responsibilities.

In response to its findings, the company has instituted measures that will ensure the office of the chief risk officer verifies all price information provided to industry publications. Dynegy will resume its practice of reporting price information to industry publications in the near future.

Dynegy Inc. owns operating divisions engaged in power generation, natural gas liquids, regulated energy delivery and communications. Through these business units, the company serves customers by delivering value-added solutions to meet their energy and communications needs.

Committee on Governmental Affairs
EXHIBIT #A-33d

Williams. Leading Energy Solutions.

October 25, 2002

Williams Discloses Natural Gas Trade Reporting Inaccuracies

TULSA, Okla. — Williams (NYSE:WMB) today said it has learned that a few traders in its natural gas trading business provided inaccurate information regarding natural gas trades to an energy industry publication that compiles and reports index prices.

The inaccuracies came to light during Williams' independent, internal review of its trading activities. That review is now being conducted in conjunction with the Commodity Futures Trading Commission's ongoing industry-wide investigation.

Williams is continuing its internal review to determine the extent of the inaccurate reporting and the impact of the activity on the price index. Further investigation will provide the company with the information it needs to determine appropriate disciplinary action.

The company no longer provides data about its natural gas trades to industry publications as a result of significantly reduced activity in its marketing and risk management business. Individuals in this portion of Williams' business were among many energy industry participants who routinely provided data about trades to publications.

Williams has informed the CFTC and other governmental authorities about its investigation and will continue to cooperate fully with those entities' inquiries and investigations.

About Williams (NYSE: WMB)

Williams moves, manages and markets a variety of energy products, including natural gas, liquid hydrocarbons, petroleum and electricity. Based in Tulsa, Okla., Williams' operations span the energy value chain from wellhead to burner tip. Company information is available at www.williams.com.

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Portions of this document may constitute "forward-looking statements" as defined by federal law. Although the company believes any such statements are based on reasonable assumptions, there is no assurance that actual outcomes will not be materially different. Any such statements are made in reliance on the "safe harbor" protections provided under the Private Securities Reform Act of 1995. Additional information about issues that could lead to material changes in performance is contained in the company's annual reports filed with the Securities and Exchange Commission.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

Committee on Governmental Affairs
EXHIBIT #A-34

OFFICE OF THE CHAIRMAN

March 4, 2002

The Honorable Joseph I. Lieberman
Chairman
Committee on Governmental Affairs
United States Senate
Washington, D.C. 20510

Dear Chairman Lieberman:

This letter and the enclosed material respond to your February 15, 2002 request for Enron-related information pertaining to FERC from January 1, 1992 until December 2, 2001. The information lists among other things: documents required to be filed at the FERC by any entity affiliated with Enron; reviews or investigations conducted in response to those filings; communications between Enron employees and FERC employees; formal and informal enforcement actions against Enron; and lists of communications with other federal departments or agencies regarding laws, regulations, and policies administered by the Commission that specifically relate to Enron.

The material is comprehensive and extensive. I believe it reflects the best efforts of the FERC staff to comply with your request as thoroughly as possible and to err on the side of including information if there is any question as to whether it is required by your inquiry. However, as you will see in explanatory information submitted with the various lists, given the relatively short time frame allowed for responding to this broad request, it has not been possible to ensure that the material provided constitutes the full universe of information that you should receive in response to your questions. This is particularly true with respect to obtaining information from former employees. We have identified areas that will require more time to respond and the specific difficulties with responding by the March 4 deadline, and we will continue to work to provide a broader response to your request.

Over the time period specified in the Committee's letter, FERC received over 148,800 filings (gas certificate filings and gas, electric and oil rate filings) of which approximately 5,000, or less than 3.5 per cent, were related to Enron or Enron affiliates.

If I can be of any further assistance in this or any other Commission matters please feel free to contact me.

Best regards,

Pat Wood III

Pat Wood, III
Chairman

Enclosure

Response to Question No. 3 in the February 15, 2002 Letter From Senators Lieberman and Thompson

Name	Office	Division	(a)	I. Who initiated the meeting	II. List all that were present at the meeting	III. What was the subject matter(s) of the meeting	IV. Give the date	IV. Date range	V. Was any action taken by the Comm. in response to the meeting	VI. Other Comments (if any)
Miller, Celeste M.	Office of External Affairs	Press Services	No							
Miller, Christopher, L.	Office of Markets, Tariffs, and Rates	Tariffs and Rates - Central	No							
Miller, Jean, M	Office of Markets, Tariffs, and Rates	Rates-Central	No							
Miller, William Scott	Office of Markets, Tariffs, and Rates	Market Development	Yes	Self initiated	Charlie Whitmore, FERC. Jule Simon, FERC. Representative from Calpine. John Stout, Reliant. Joel Newton, Dynegy. Jim Steffes, Enron.	Possible settlement of generators with the state of California.		May-01	None.	
Miller, William Scott	Office of Markets, Tariffs, and Rates	Market Development	Yes	Sarah Novosell, Enron	Rick Shapiro, Enron. Sarah Novosell, Enron. One other Enron representative who worked legislative issues and whose name I cannot remember.	Purpose was to discuss general market design issues for the whole country going forward.		Jun-01	None	
Miller, William Scott	Office of Markets, Tariffs, and Rates	Market Development	Yes	Christy Nicolay	Chirsty Nicolay, Enron.	Tour of the Commission's new market room known as the "Market Observation Resource" (MORe)		Jul-01	None.	
Miller, William Scott	Office of Markets, Tariffs, and Rates	Market Development	Yes	Enron	Two regulatory people from Enron whose name I don't remember. Robert Pease, FERC.	Allegations by Enron that the CAISO was intentially constraining the transmission line from California to Oregon in order to keep prices artificially low.		Oct-01	None.	
Miller, William Scott	Office of Markets, Tariffs, and Rates	Market Development	Yes	Self initiated	Rick Shapiro, Enron	Discuss Enron's plans for continuing performance on all obligations in light of the S&P downgrade and the end of the Dynegy deal.		28-Nov-01	None.	A general concern regarding a decrease in liquidity of the power and gas markets had been expressed over the last few months if Enron reached default. We were trying to ascertain what Enron was doing to assure performance.

Response to Question No. 3 in the February 15, 2002 Letter From Senators Lieberman and Thompson

Name	Office	Division	(a)	I. Who initiated the meeting	II. List all that were present at the meeting	III. What was the subject matter(s) of the meeting	IV. Give the date	IV. Date range	V. Was any action taken by the Comm. In response to the meeting	VI. Other Comments (if any)
Miller, William Scott	Office of Markets, Tarrifs, and Rates	Market Developme nt	Yes	Rick Shapiro, Enron	Rick Shapiro, Enron. Greg Whalley (sp), Enron.	Market conditions, Enron performance on obligations and methods used to mitigate effects of any non-performance.		28-Nov-01	None.	Discussed effort by Enron over the last few weeks to "flatten" their books (ie., be neither long or short on obligations), so that it would relatively easy to unwind obligations and have them picked up by other market participants in the event of an Enron default.
Miller, William Scott	Office of Markets, Tarrifs, and Rates	Market Developme nt	Yes	Rick Shapiro, Enron	Rick Shapiro, Enron.	Performance by Enron on obligations, particularly retail obligations.		29-Nov-01	None.	
Miller, William Scott	Office of Markets, Tarrifs, and Rates	Market Developme nt	Yes	Joe Hartsoe, Enron	Joe Hartsoe, Enron	Discuss the performance and delivery of Enron pipelines, particularly Northen Natural Gas and Transwestern.		30-Nov-01	None.	
Miller, William, Scott	Office of Markets, Tarrifs, and Rates	Division of Market Developme nt	Yes	Self initiated	Gerald Williams, FERC. Michele Voloso, FERC. Julie Simon, EPSA. Scot Krantz, Duke Energy. John Robinson, FERC. Lee Barrett, Duke Energy. Brian Harrington, FERC. Ellen Wolfe, Enron. Diane Fetherstone, Constilation Energy. Mike McCullagh, Southern Company. John Morris, PG&E NEG. Jack Hawks, PG&E NEG. George Radan, PG&E NEG. Joe Hartsoe, Enron. Mark Bennett, EPSA. Peter Kadzik, Dickstein, Shapiro. John Kroeger, FERC. Camilla Ng, FERC. Kumar Agarrwal, FERC. Robert Fallon, Dickstein, Shapiro. Andrea Wolfman, FERC. Mary Hain, Enron.	Discuss the Marketer sector's views on causes of the California Energy Crisis. One of several meetings with all industry sectors, regulators and interest groups.		Aug. 20-27, 2000	No.	

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

Committee on Governmental Affairs
EXHIBIT #A-35

OFFICE OF THE CHAIRMAN

April 12, 2002

The Honorable Joseph I. Lieberman
Chairman
Committee on Governmental Affairs
United States Senate
Washington, D.C. 20510

Dear Senator Lieberman:

This letter and the enclosed material respond to your March 27, 2002 letter which asked the Commission to list all communications between the Commission and other federal departments or agencies or the Executive Office of the President from January 1, 1992 to December 2, 2001.

If I can be of any further assistance in this or any other Commission matter, please feel free to contact me.

Best regards,

Pat

Pat Wood, III
Chairman

Enclosure

March 27, 2002 Request for Additional Information

Question:

Please list all communications between the Commission and other federal departments or agencies or the Executive Office of the President from January 1, 1992 to December 2, 2001, referring or relating to Enron. For each such communication, please identify:

a) who sent the communication

b) who received the communication

c) the date of the communication

d) the subject matter of the communication

e) any action taken in response to the communication

f) for any meetings responsive to this request, the date of the meeting and all those who attended the meeting.

Answer:

The answer to this question as it pertains to communications between current FERC staff and other federal departments or agencies or the Executive Office of the President is reflected on the attached. The answer to this question as it pertains to communications between former senior FERC staff (division director or above) will be supplied as soon as we receive their responses. For that purpose, on April 4, 2002, we sent the Committee's March 27, 2002 letter to approximately 100 people, with a request to respond by April 19, 2002. We intend to transmit their responses to the Committee during the week of April 22, 2002.

Responses Received from Current FERC Staff

- Ellen Armbruster – Office of Energy Projects

Several telephone conversations with Laura Dean, Advisory Council on Historic Preservation, October 1998, regarding the crossing of the Illinois & Michigan Canal, a National Historic Landmark, in Northern Border Project No. CP95-194-000.

Telephone conversation with Keith Ryder of the Corps of Engineers, October 21, 1998, regarding the crossing of the Illinois & Michigan Canal in Project No. CP95-194-000.

Telephone conversation with Brain Smith of the Corps of Engineers, October 29, 1998 regarding the crossing of the Illinois & Michigan Canal in Project No. CP95-194-000.

Telephone conversation with Diane Miller, National Park Service, November 2, 1998, regarding the crossing of the Illinois & Michigan Canal in Project No. CP95-94-000.

- Kim Bruno – Office of General Counsel

On June 28, 2001, I had a telephone conversation with Michael Macchiaroli, Assistant Director, Office of Risk Management and Control at the Securities and Exchange Commission, and someone named George from his division. We discussed the analysis of risk management filings by companies and, in particular, Enron filings. No action or meetings were taken in response to my telephone call.

- Van Button – Office of Energy Projects

Contacts related to Florida Gas Transmission with another Federal agency:

a) Telephone conversations from: Van Button, archaeologist, OEP/FERC
b) To: Daniel Pagano, staff, Washington, DC Office, Advisory Council on Historic Preservation.
c) The dates of the communications: 3/9/93; 5/5/93; 5/14/93; 11/3/93; 11/23/93; 12/20/93; 12/22/93; and 2/7/94.
d) Subject: development and review of a Programmatic Agreement regarding required archaeological and historic studies for the Florida Gas Transmission Company FGT III Gas Pipeline Project in Florida, Alabama, Mississippi, and Louisiana.
e) Action taken in response to the communication: The Programmatic Agreement was executed and implemented.
f) No meetings were held.

Contacts related to Norther Natural Gas Company with another federal agency:

a) Telephone conversations from: Van Button, archaeologist, OEP/FERC.
b) To: Ralph Augustin, regulatory staff, Army Corps of Engineers, St. Paul District.
c) The dates of the communication: 10/22/97 and 11/7/97.
d) Subject: Northern Mississippi River Crossing Pipeline Gas Project, Minnesota, failure of silt curtain to prevent escape of sediment into the river during construction.
e) Any action taken in response to the communication: none, problem identified as minor.
f) No meetings were held.

- Rob Gramlich – Office of the Chairman

Contact with National Economic Council

a) Sender: Rob Gramlich, Economic Advisor to Chairman Wood.
b) Receiver: Robert McNally, National Economic Council
c) Date: November 28, 2001
d) Subject: I notified Mr. McNally that there were two potential system-wide problems which energy market participants and FERC had identified from Enron's defaulting on energy contract obligations, both low probability but worth being aware of, and that we were monitoring them and might talk to experts at other agencies. The two potential concerns were physical delivery interruption and cascading credit strain as a result of Enron energy contract default.
e) Actions taken: None that I am aware of.
f) Meetings: There were no meetings.

Contact with Federal Reserve Board of San Francisco

a) Sender: Rob Gramlich, Economic Advisor to Chairman Wood
b) Receiver: an economist who took the call in place of an energy economist, Fred Furlong, who was on travel. I do not remember her name.
c) Date: November 28, 2001.
d) Subject matter: I referred an issue for their consideration that had been brought to our attention by energy market participants. The issue was whether there was any potential for system-wide credit strain as a result of Enron defaulting on its energy contract obligations.
e) Actions taken: The Fed representative did not say what they were doing. She was aware of the situation.
f) Meetings: There were no meetings.

- Elizabeth Rylander – Office of General Counsel

a) Sender: Brenda Mackall, Work Group Lead, Correspondence and Records Management, Office of the Executive Secretariat, Department of Energy.
b) Recipient: Paul McKee, Executive Secretariat, FERC.
c) Date: August 28, 2001.
d) Subject matter: Forwarding letters from Cynthia C. Sandherr (Vice President, Federal Government Affairs, The New Power Company) to Francis S. Blake (Deputy Secretary-Designate, Department of Energy) and Robert Gordon Card (Under Secretary, Department of Energy). Ms. Sandherr's letter forwarded NewPower testimony from a House hearing, supporting residential customers' right to install time-of-use meters in their homes, and stating that Congress and the Commission should address the lack of uniform business rules for wholesale and retail transactions.
e) Action taken: I was asked to write a draft response to Ms. Sandherr's inquiry, and I did so. The letter was eventually signed by Don Chamblee, as Acting Director of the Office of External Affairs.
f) Meetings: I do not know of any interagency meetings responsive to this request.

Committee on Governmental Affairs
EXHIBIT #A-36

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

San Diego Gas & Electric Company,
Complainant,

v.

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

Docket Nos. EL00-95-004
EL00-95-005
EL00-95-019
EL00-95-031

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

Docket Nos. EL00-98-004
EL00-98-005
EL00-98-018
EL00-98-030

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 Nos. EL01-10-000
EL01-10-001

ORDER ESTABLISHING EVIDENTIARY HEARING PROCEDURES,
GRANTING REHEARING IN PART, AND
DENYING REHEARING IN PART

(Issued July 25, 2001)

This order establishes the scope of and methodology for calculating refunds related to transactions in the spot markets operated by the California Independent System Operator Corporation (ISO) and the California Power Exchange Corporation (PX) during the period October 2, 2000 through June 20, 2001. The Commission makes clear that transactions subject to refund are limited to spot transactions in the organized markets operated by the ISO and PX during the period October 2, 2000, through June 20, 2001, and include sales by public and non-public utilities into these markets. The order also establishes an evidentiary hearing proceeding in order to further develop the factual record in Docket No. EL00-95-031, et al., so that refunds may be calculated. The order grants rehearing in part and denies rehearing in part of limited portions of earlier orders issued in this proceeding. In addition, the Commission establishes another proceeding before an Administrative Law Judge to explore whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest from December 25, 2000 through June 20, 2001, and the calculation of any refunds associated with such charges.

Background

In an order issued August 23, 2000,[1] the Commission instituted formal hearing proceedings under section 206 of the Federal Power Act (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. In instituting an investigation into the reasonableness of the rates charged, however, the Commission denied a request by San Diego Gas and Electric Company (SDG&E) contained in SDG&E's complaint against all sellers of energy and ancillary services into the ISO and PX markets subject to the Commission's jurisdiction, that the Commission impose a $250 price cap for sales into those markets. The Commission denied this request in the August 23 Order, on the grounds that SDG&E had not provided sufficient evidence to support an immediate seller's price cap.[2] The Commission established a refund effective date of 60 days after publication of notice in the Federal Register of the Commission's intent to institute a proceeding.[3]

The Commission issued an order on November 1, 2000 finding 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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[1]San Diego Gas & Electric Company, et al., 92 FERC ¶ 61,172 (2000), reh'g pending (August 23 Order).

[2]92 FERC at 61,606.

[3]Id. at 61,608.

conditions."[4] The order noted that, "[w]hile 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." [5]

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."[6] 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. The order also contained extensive discussion of the Commission's authority to direct refunds, for the periods both before and after the refund effective date, and concluded that the Commission is not authorized by the FPA to order refunds prior to the October 2 refund effective date. Several parties sought rehearing of this aspect of the November 1 Order.[7]

The Commission adopted many of the proposed remedies presented in the November 1 Order in an order issued December 15, 2000.[8] The December 15 Order reiterated the earlier findings 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, had caused, and continued 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, including, in part: (1) eliminating the requirement that the IOUs sell all of their generation into and buy all their energy needs from the PX so as to

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[4] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,121 at 61,349-50 (2000), reh'g pending (November 1 Order).

[5] Id. at 61,350.

[6] Id.

[7] See, e.g., requests for rehearing of the California Electricity Oversight Board (Oversight Board), the Public Utilities Commission of the State of California (California Commission), PG&E, SoCal Edison, and the City of San Diego. Other determinations in the November 1 Order are also pending rehearing; these issues will be addressed in a future order.

[8] San Diego Gas & Electric Co., et al., 93 FERC ¶ 61,294 (2000), reh'g pending (December 15 Order)

terminate the over reliance on spot markets; (2) adopting an advisory benchmark for assessing prices of long-term electric supply contracts in order to provide guidance for market participants to evaluate the reasonableness of long-term prices; (3) requiring market participants to preschedule 95 percent of their load prior to real time and penalizing those who do not, so as to eliminate market participants' chronic underscheduling with the ISO; and (4) requiring an independent governing board for the ISO.

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 having to pay refunds for prices charged above the breakpoint. The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology by May 1, 2001. In a separate order, the Commission established a settlement conference to facilitate forward contracting by California investor owned utilities.[9] The Chief Administrative Law Judge convened discussions over five days in December 2000 and January 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 $150/MWh break-point price. 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.

On March 9, 2001, the Commission issued an order addressing above-breakpoint transactions that occurred in January.[10] The March 9 Refund Order directed refunds from sellers for transactions occurring during Stage 3 Emergencies (when ISO reserves fell below 2.5 percent) above a proxy market clearing price ($273/MWh for that month), or alternatively, required sellers to submit additional cost or other justification for those transactions.[11] Parties requested rehearing of the March 9 Refund Order on many grounds. Among those were PG&E, SDG&E, and SoCal Edison's objections to the

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[9]Forward Contracting by California Utilities, 93 FERC ¶ 61,295 (2000).

[10]San Diego Gas & Electric Co., et al., 94 FERC ¶ 61,245 (2001), reh'g pending (March 9 Refund Order).

[11]The Director of the Office of Markets, Tariffs and Rates issued notices announcing the proxy market clearing prices for the months of February, March, April, and May 2001 on March 16, April 16, May 14, and June 15, respectively.

Commission's conclusion that it has no authority to order non-public utility sellers to make refunds.[12] Additionally, numerous parties argued that price mitigation should apply during all hours.[13]

On April 26, 2001, the Commission issued its order adopting a prospective monitoring and mitigation plan for wholesale sales through the organized real-time markets operated by the ISO.[14] The Commission's plan, in pertinent part, enhanced the ISO's ability to coordinate and control planned outages during all hours; required certain sellers to offer the ISO all their available power in real time during all hours; established conditions, including refund liability, on public utility sellers' market-based rate authority to prevent anti-competitive bidding behavior in the real-time ISO markets during all hours; and established a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's organized markets for real-time sales during system emergencies. In the April 26 Order, the Commission also established an inquiry into whether a price mitigation plan similar to the one for the California ISO's organized spot markets should be implemented in the Western Systems Coordinating Council (WSCC) and invited comment on how such a plan should be structured.

On June 19, 2001, the Commission expanded the price mitigation plan on rehearing, imposing curbs not only on California ISO organized spot market sales during all hours, but also constraining prices for bilateral spot market sales throughout the WSCC for the period June 20, 2001 through September 30, 2002.[15] The order retained the use of a single price auction and must-offer and marginal cost bidding requirements when reserves are below 7 percent in the California ISO spot markets. Under the plan, the ISO market clearing price will also serve as a limit on prices in all other spot market sales in the WSCC during reserve deficiencies in California. Sellers in all spot markets in the WSCC will receive up to the clearing price without further justification. Sellers other than marketers will have the opportunity to justify prices above the market clearing price during reserve deficiency hours.

In the June 19 Order, the ISO market clearing price for reserve deficiency hours was also adapted for use in all Western spot markets when reserves are above 7 percent. Prices during non-reserve deficiency hours cannot, absent justification, exceed 85 percent of the highest hourly clearing

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[12]See March 9 Refund Order, 94 FERC at 61,864.

[13]See, e.g., Rehearings of California Commission, ISO, SDG&E, City of San Diego, County of San Diego, and PG&E. Other determinations in the March 9 Order are also pending rehearing; these issues will be addressed in a future order.

[14]San Diego Gas & Electric Company, et al., 95 FERC ¶ 61,115 (2001), reh'g pending (April 26 Order).

[15]San Diego Gas & Electric Company, et al., 95 FERC ¶ 61,418 (2001), reh'g pending (June 19 Order).

price that was in effect during the most recent Stage 1 reserve deficiency period (i.e., when reserves are below 7 percent) called by the ISO. These measures were applied to non-public utility sellers as well as public utilities to the extent they voluntarily sell power in the ISO or other WSCC spot markets or voluntarily use the ISO's or other Commission-jurisdictional interstate transmission facilities elsewhere in the WSCC.

In addition, the Commission announced that it would hold a settlement conference before an Administrative Law Judge in order to resolve refund issues for past periods, among other things. The Commission's Chief Judge convened the conference from June 25 through July 9, 2001.

Chief Judge's Report and Recommendation

On July 12, 2001, the Chief Judge issued a report detailing his efforts to forge a settlement among the parties.[16] He explains that, while a global settlement agreement was not achieved, he believes that the negotiations were constructive. The Report finds that refunds owed to purchasers of electricity "amount to hundreds of millions of dollars, probably more than a billion dollars in aggregate sum," although not the $8.9 billion claimed by the State of California.[17] The Report mentions offers made by several sellers into the California market totaling $703.6 million, contingent upon reaching a global settlement of all issues.

According to the Report, efforts were hampered by incomplete data. The Chief Judge had requested the parties to provide, among other things: (1) the terms and prices of all forward contracts; (2) the amounts that California Department of Water Resources (DWR), the IOUs, and the ISO believe they owe to sellers; and (3) system load figures broken down by component. These data were not made available in their entirety. The Report also notes that the Pacific Northwest Parties did not have data on the amount of refunds due them nor balances past due from purchasers. For these and other reasons, the Chief Judge was not able to determine the total volume of the spot market, nor were parties able to agree about the size of the market subject to the June 19 Order. The Report concludes that the differences between what the State and the sellers believe should be refunded raise material issues of fact. Further, the Report states, "[t]he appropriate numbers to calculate potential refunds involve factual disputes."[18] Thus, the Chief Judge recommends that the Commission order a trial-type evidentiary hearing limited to developing a factual record against which to apply a refund methodology.

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[16]San Diego Gas & Electric Company, et al., 96 FERC ¶ 63,007 (2001) (Report).

[17]Id., slip op. at 3.

[18]Id., slip op. at 5.

The Chief Judge's recommended refund methodology would begin with the price mitigation approach set forth in the June 19 order, with several modifications for dealing with past, as opposed to future, transactions. Key differences include: (1) using actual, rather than hypothetical, heat rates; (2) using daily spot gas prices rather than monthly bid-week prices; (3) separating the state's gas market into northern and southern zones; (4) excluding emission costs from the market clearing price and treating them as an additional expense that may be subtracted from refund calculations; and (5) not using the 85 percent price ceiling for non-emergency hours, and instead recalculating each hour to determine the amount by which actual prices exceeded the mitigated price. The Chief Judge recommends retaining the 10 percent credit adder for sales after January 5, 2001, and not including interest unless the refund amount exceeds payments that are past due to the seller.

Docket No. EL01-10-000

On October 26, 2000, Puget Sound filed a complaint in Docket No. EL01-10-000 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 [19] wholesale power markets. Specifically, Puget Sound sought an order that prospectively capped 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. The December 15 Order declined to implement a region-wide price cap because it found that such a pricing methodology was impracticable given the market structure in the Pacific Northwest and because complainant had not met its burden of proof to justify such an action. [20] Puget Sound and others timely sought rehearing of the December 15 Order's determination not to impose a regional price cap or other mitigation.

On June 22, 2001, Puget Sound filed a motion to dismiss its complaint and a notice of withdrawal of its complaint and its subsequent rehearing request. Puget Sound explains that the June 19 Order satisfies its complaint because it implements price mitigation measures throughout WSCC. Several parties filed answers to the motion. Bonneville Power Administration (Bonneville) states that the Commission must fully resolve the issues raised in the complaint regardless of whether it grants Puget Sound's motion, arguing that the focus on spot markets in the June 19 Order is not appropriate outside of California, where utilities rely on forward contracts. The City of Tacoma and Port of Seattle

[19]Puget Sound indicated 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) (1994).

[20]December 15 Order, 93 FERC at 62,019.

jointly filed an answer opposing the motion on the basis that dismissal would unduly prejudice parties outside of California that relied on the existence of the complaint, and arguing that the issues raised in the complaint are an integral part of market issues that the Commission is addressing in the SDG&E proceeding.

The City of Seattle (Seattle) filed an answer and a motion to intervene out-of-time in Docket No. EL01-10-000. Seattle contends that, although the June 19 Order satisfied Puget Sound's complaint, the Commission should keep the proceeding open because non-California market participants have paid prices that are unjust and unreasonable, and because retaining the proceeding would permit the Commission greater flexibility in determining the scope and effective date for refunds.

The Washington Commission and the Attorney General of Washington state several principles that they believe should guide the Commission's determination of whether and how to order refunds for and by the utilities in the Pacific Northwest, i.e., that refunds should be symmetrical as to all purchases and sales, and unbiased with respect to acquisition strategies. In addition, the Attorney General of Washington moves to intervene out-of-time.

On June 22, 2001, unaware of Puget Sound's motion filed on the same day, the Commission issued an order clarifying the June 19 Order to indicate that parties in the settlement proceeding were not limited to settling only California-related matters, but could also discuss settling past accounts related to sales in the Pacific Northwest. The Chief Judge's Report stated that there was little time to address the issues raised by the parties in Puget Sound's proceeding and noted that they did not have data on unpaid balances nor on refunds due them.

Discussion

A. Procedural Matters

A number of entities filed late motions to intervene in this proceeding, as described below. On December 28, 2000, the Southern California Water Company (SoCal Water) filed an intervention in Docket No. EL00-95-000, et al.[21] On January 30, 2001, the New Mexico Regulation Commission (New Mexico Commission) filed a motion to intervene out-of-time in Docket No. EL00-95-000, et al., raising no substantive issues. On February 9, 2001, the Public Utilities Commission of Nevada (Nevada Commission) filed a motion to intervene out-of-time with comments encouraging recognition of the regional scope of the crisis. On April 9, 2001, the American Public Power Association (APPA) filed a motion to intervene and request for rehearing of the March 9 Refund Order. On July 12, 2001, the Washington Utilities and Transportation Commission (Washington Commission) filed a motion for clarification of its intervenor status, or, in the alternative, a motion to intervene out-of-time in Docket

[21] SoCal Water subsequently requested rehearing of the December 15 Order.

No. EL00-95-031, et al. Finally, on July 17, 2001, the People of the State of California, ex rel. Bill Lockyer (Attorney General of California) moved to intervene out-of-time in Docket No. EL00-95-031, et al.

In addition, on December 26, 2000, the Oregon Public Utilities Commission (Oregon Commission) filed a late motion to intervene in Docket No. EL00-10-000, stating that it had not yet developed a position on Puget Sound's complaint. On January 16, 2001, the Washington Commission also filed a late motion to intervene in that proceeding with comments in support of Puget Sound's request for rehearing. The City of Seattle (Seattle) and the Attorney General of Washington filed motions to intervene out-of-time in Docket No. EL01-10-000 on July 9, 2001.

The Commission ordinarily does not permit late interventions after an order has been issued, particularly for the purpose of requesting rehearing.[22] However, over the course of the SDG&E proceeding, the Commission has expanded the scope of its focus from just California to include the entire Western interconnect and also to implicate wholesale spot market transactions of non-public utilities. We find good cause, therefore, to grant the untimely, unopposed motions to intervene in Docket No. EL00-95-000 filed by the entities described above.[23]

These intervenors must accept the record as it had developed as of the date of their intervention, and their participation in this proceeding is limited to the issues that arose after the date each requested to participate in these proceedings. Thus, the request for rehearing of the December 15 Order filed by SoCal Water will be dismissed because it was not a party as of the date that order was issued. Similarly, APPA's request for rehearing of the March 9 Refund Order will be dismissed because it was not a party as of the date that order was issued.

In view of the interest of the Oregon Commission, the Washington Commission, the Attorney General of Washington, and Seattle, and the absence of any undue prejudice or delay, we will grant their untimely, unopposed motions to intervene. We also clarify that the companies listed individually in

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[22] See, e.g., Southern Company Services, Inc., 92 FERC ¶ 61,167 (2000); Consolidated Edison, Inc. and Northeast Utilities, 92 FERC ¶ 61,014 (2000), order denying reh'g, 94 FERC ¶ 61,079 (2001).

[23] In the May QF Order, we intended, but inadvertently failed, to grant the timely, unopposed motion to intervene of Carson Cogeneration Company, LP, Mojave Cogeneration Company, LP, O.L.S. Energy-Camarillo, O.L.S. Energy-Chino, and PE Berkeley, Inc. (collectively, QF Petitioners) filed in Docket No. EL00-98-000, and the untimely, unopposed motion to intervene of Berry Petroleum Company in Docket No. EL00-95-020. We do so in this order.

the caption of the March 9 Refund Order are respondents, and thus, under Rule 102 of the Commission's Rules of Practice and Procedure,[24] are parties in the SDG&E proceeding.

B. Scope of Refunds

1. The Commission's Retroactive Refund Authority

a. Introduction and Summary

In the Commission's November 1 Order, we concluded that the FPA and the weight of court precedent strongly suggest that refunds prior to October 2, 2000 are impermissible under the circumstances of this case, which arose in a section 206 complaint context. In the December 15 Order, we addressed prospective remedies necessary to correct market dysfunctions and to assure just and reasonable rates, but did not address the comments on retroactive refund authority. We do so here to clarify our statutory refund authority and the scope of refunds subject to the hearing being ordered below.

We have again examined the statute, its legislative history and the case law, and have analyzed the arguments raised on this issue in comments on and requests for rehearing of the November 1 Order. We conclude that FPA section 206 does not permit the Commission to require refunds of unjust and unreasonable rates charged prior to a date 60 days after the filing of a complaint or 60 days after the initiation of a Commission investigation on its own motion. To order such refunds would contravene explicit refund limitations that Congress put in FPA section 206. While that refund authority can be expanded in limited circumstances (e.g., where sellers have charged a rate other than the filed rate or where an appellate court has found that the Commission committed legal error), as discussed below, none of those circumstances is present here. Thus, in the specific situation present here, we cannot order refunds of unjust and unreasonable rates charged prior to October 2, 2000, the start of the refund effective period.[25] Accordingly, we will deny the requests for rehearing of the November 1 Order challenging the order's findings about the Commission's retroactive refund authority, i.e., refund authority prior to October 2, 2000.[26]

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[24] 18 C.F.R. § 385.102(c)(2) (2001).

[25] The FPA, with one exception, permits refunds only for a period of 15 months after the refund effective date. The exception is that if a public utility engages in dilatory behavior in a section 206 proceeding, the Commission can extend the refund period beyond 15 months from the refund effective date.

[26] To the extent parties raise the same arguments on rehearing of the December 15 Order, we similarly deny rehearing.

b. The Commission's Retroactive Refund Authority

Several parties argue that the Commission's statutory duty to protect consumers and its broad legal and equitable authority to do so requires that the Commission remedy unjust and unreasonable rates for the period prior to October 2 by ordering refunds.[27] Other parties agree with the November 1 Order's conclusion that the Commission has no legal authority to grant refunds for overcharges prior to October 2.[28] As discussed below, we conclude that the Commission lacks the authority to order retroactive refunds of unjust and unreasonable rates charged prior to October 2.

i. Sections 205 and 206 of the FPA

Comments

Several parties argue that because sections 205 and 206 of the FPA require that the Commission ensure just and reasonable rates, the Commission, having found the preOctober 2 rates to be unjust and unreasonable, is obligated to order refunds for that period. They further argue that the Commission is not prohibited from ordering retroactive refunds of market-based rates.

Other parties argue that neither section 205 nor 206, on its face, grants the Commission authority to order retroactive refunds. Thus, they maintain that the Commission may not order refunds for the pre-October 2 period.

Commission Determination

A number of parties confuse the just and reasonable standard with the authority to order retroactive refunds of unjust and unreasonable rates. Whether rates are unjust and unreasonable is a separate issue from whether the Commission is authorized under the statute to order refunds retroactively. Under FPA section 206, if the Commission finds that rates no longer meet the just and reasonable standard, the Commission has a statutory obligation to fix a new rate or to fix practices "to

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[27] E.g., Comments filed November 22, 2000, by Southern California Edison Company (SoCal Edison), Pacific Gas and Electric Company (PG&E), SDG&E, City of San Diego, County of San Diego, California Commission, TURN/UCAN, California State Senator Morrow, Oversight Board, California Legislature, San Diego Association of Governments.

[28] E.g., Comments of DOE, Enron, Calpine, Dynegy, PPL EnergyPlus, Reliant, Duke Energy, Williams, IEP, WPTF, Xcel Energy. DOE also comments that Congress should examine whether to amend the FPA to provide the Commission with authority to require retroactive refunds in the future.

be thereafter observed."[29] In amending FPA section 206, Congress did not give the Commission authority to modify unjust and unreasonable rates retroactively. As discussed in the Appendix to the November 1 Order, when Congress passed the FPA in 1935, it excluded a provision from the original bill that would have authorized the Commission to retroactively order reparations for charges found to be excessive or unreasonable if a complaint were filed within two years from the date of payment. Courts later concluded that this exclusion showed that Congress intended that the Commission have authority to only grant relief in a section 206 proceeding prospectively from the date of its order. See, e.g., City of Bethany v. FERC, 727 F.2d 1131 (D.C. Cir. 1984), cert. denied, 469 U.S. 917 (1984).

As a result, Congress added limited refund authority to section 206 in the Regulatory Fairness Act of 1988 (RFA). S. Rep. No. 491, 100th Cong., 2d Sess. 3-4 (1988), reprinted in 1988 U.S.C.C.A.N. 2685. As amended, FPA section 206 restricts the Commission's authority to establish a refund effective date to no earlier than 60 days after the date that a complaint is filed or the Commission initiates an investigation. Therefore, section 206 does not permit retroactive refund relief for rates covering periods prior to the filing of a complaint or the initiation of a Commission investigation, even if the Commission determines that such past rates were unjust and unreasonable.

ii. The Filed Rate Doctrine and the Rule Against Retroactive Ratemaking

Parties urging retroactive refunds make several arguments concerning the filed rate doctrine and its corollary, the rule against retroactive ratemaking. Taken together, the doctrine and its corollary stand for the propositions that a utility may charge only those rates that are on file with and approved by the Commission, and conversely that the Commission may not alter those filed rates retrospectively. The arguments against the application of the doctrine and its corollary can be condensed to the following: the filed rate doctrine does not apply to market-based rates; the Commission's past market-based rate authorizations in California markets constituted legal error; and the rates charged were inconsistent with sellers' filed rates. According to these parties, the filed rate doctrine does not preclude retroactive refunds in these specific circumstances.

(a) Whether the Filed Rated Doctrine Applies to Market-Based Rates

Comments

Oversight Board and County of San Diego argue that the filed rate doctrine does not apply to market-based rates because the actual rates have not been filed with the Commission, and because prices fluctuate with the market. Accordingly, they assert that there is no fixed rate on file on which buyers and sellers could rely, and which would prohibit retroactive refunds.

[29] 16 U. S.C. § 824e(a) (1994).

County of San Diego contends that several principles underlying the filed rate doctrine and the rule against retroactive ratemaking do not apply to market-based rates and, thus, are not dispositive in this case. Specifically, it contends that: the principle that regulated companies can charge only those rates of which the agency is cognizant does not apply to these facts, because the Commission no longer receives prior notice of actual market-based rates; the nondiscrimination principle does not apply, because market-based pricing allows utilities to sell at different rates to different customers; and the principle of predictability is not applicable, because the market, not a fixed rate or published formula, determines prices. Instead, County of San Diego asserts that another principle underlying the filed rate doctrine – the principle of reasonable expectations – is dispositive. It contends that market participants and the Commission clearly expected that competitive forces would be adequate to restrain prices in the California markets to just and reasonable levels, whereas sellers had no legitimate or reasonable expectation of being able to demand unjust and unreasonable prices due to an absence of competition. Thus, it argues that the reasonable expectations rationale underlying the filed rate doctrine supports a requirement for refunds in this case.[30]

Commission Determination

Under the FPA, sections 205 and 206 are the statutory foundation for the filed rate doctrine and the rule against retroactive ratemaking. FPA section 205(c) states: "Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate . . . schedules showing all rates and charges subject to the jurisdiction of the Commission . . . ." This provision does not distinguish between cost-based and market-based rates. Nor does the provision require that the Commission receive prior notice of market-based rates, as San Diego contends. [31]

As the Court of Appeals for the District of Columbia Circuit recently recognized, "[t]he Commission has held that traditional utilities and power marketers who engage in market-based rate

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[30] Comments of County of San Diego at 11-13.

[31] Contrary to County of San Diego, the rationales underlying the filed rate doctrine apply to market-based rates. First, San Diego is incorrect that Section 205(c) requires prior notice of the actual market-based, numerical rates. In addition, the fact that a market-based tariff or rate schedule is on file instead of a specific, quantified rate is not dispositive, so long as buyers know (or can know by examining the Commission's public files) the type of rates authorized for each seller. The principle of predictability requires that the parties know the type of rate being used, not necessarily the exact numerical rate. When a buyer knows market-based rates are being used, the buyer can predict that rates will fluctuate with differing conditions, and can plan accordingly. That is all that is required. Thus, the filed rate doctrine and its corollary, the rule against retroactive ratemaking, apply to market-based rates.

transactions are required to file quarterly reports summarizing transactions and that these reports satisfy the filing requirements of § 205(c),"[32] and the court did not question the Commission's judgment in this regard. Consequently, the Commission's current procedures for quarterly filing of market-based transactions satisfy the section 205(c) filing requirements for market-based rates. The market-based rates at issue here were on file with and approved by the Commission. Second, in response to section 206 complaints and our own investigation, the December 15 Order implemented a number of structural changes to the existing California market mechanisms to eliminate those features that were creating the possibility of unjust and unreasonable rates. The structural changes satisfied our section 206(a) obligation to determine the just and reasonable provisions to be thereafter in force.

We find San Diego's reasonable expectation principle not to be a tenet of the filed rate doctrine, but merely a restatement of our statutory duty to set just and reasonable rates. San Diego's effort to engraft this principle into the filed rate doctrine seeks to evade the distinction, noted above, between our delegated authority under section 206 to find that existing rates are unjust and unreasonable and the statutory restriction on refunds in such cases. The filed rate doctrine cannot give us greater refund authority than that allowed in the FPA, and therefore we reject San Diego's claim that its reasonable expectation rationale supports a requirement for refunds in this case.[33]

To conclude, the filed rate doctrine applies to the market-based rates at issue here, and the statutory limitations on our refund authority prohibit retroactive refunds.

(b) Legal Error

Comments

Some parties argue that the Commission's market-based rate authorizations relied on determinations that the markets were competitive, but that the markets have now been shown not to be competitive. They argue that, by allowing market-based rates in markets that were not workably competitive, the Commission committed legal error, which constitutes a basis for the Commission to order retroactive refunds to correct its mistakes.

Commission Determination

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[32]Power Co. of America, L.P. v. FERC, 245 F.3d 839, 846 (D.C. Cir. 2001).

[33]See Towns of Concord, Norwood and Wellesley v. FERC, 955 F.2d 67, 73 (D.C.Cir 1992) (rejecting argument that assumes a "'right' ceases to exist unless it is backed up by a remedy, that the Commission's denying refunds equals the Commission's authorizing the utility to violate the filed rate doctrine . . . . This is good advocacy but the case cannot be decided on any such theory.").

The parties' reliance on a "legal error" theory is flawed. First, we disagree that the Commission committed legal error by allowing market-based rates to remain in effect in California. Rather than eliminate market-based rates entirely, as these parties seem to advocate, the Commission reasonably sought to correct the flaws that could cause unjust and unreasonable rates in certain conditions. The December 15 Order contained a number of remedial measures designed to correct those flaws. As found by the Ninth Circuit, "FERC's actions, taken together, appear to be fully consistent with § 206(a)."[34] Thus, we disagree that the Commission's approach can be considered to constitute legal error.

Second, while we recognize that retroactive refunds can be ordered where a court reverses a non-final Commission decision on the merits,[35] the parties have challenged the Commission's original decisions to grant market-based pricing authority to various applicants. Those orders have, however, become final and non-appealable under FPA section 313, and thus courts would lack jurisdiction to review those decisions. Third, to the extent that the parties are raising questions about the operation of specific sellers' exercise of market-based pricing, those cases must proceed under section 206, as, in fact, this case does. In a section 206 complaint, our refund authority is confined by the statutory language to commence 60 days after the complaint was filed, or October 2, 2000 in the instant case. We do not see how a court could find legal error in our decision to follow the statutory requirement.

(c) Whether the Rates Charged Were Inconsistent with a Competitive Market Rate

Comments

Several parties argue that market-based rates are just and reasonable only if the market is sufficiently efficient and sufficiently free from the ability of market participants to exercise market power so that actual prices charged in the marketplace approximate the "true" market price, i.e., the price that would obtain in a hypothetically "fully competitive" and efficient market. The parties argue that there

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[34] In re: California Power Exchange Corp., 245 F.3d 1110, 1121 (9th Cir. 2001).

[35] See United Gas v. Callery Properties, 382 U.S. 223, 229 (1965) (while the Commission has no power to make reparation orders, its power to fix rates being prospective only, it is not so restricted where its order, which never became final, has been overturned by a reviewing court); Reynolds Metals Co. v. FERC, 777 F.2d 760, 763 (D.C. Cir. 1985)(same). See also Tennessee Valley Mun. Gas Assn. v. FPC, 470 F.2d 446, 453 (D.C. Cir. 1972) (granting of refunds did not violate anti-reparations language in the statute which was designed to protect established expectations under legally established rate schedules. One "cannot claim justifiable reliance or protectable expectations based on [Commission] action which was illegal").

was an implied condition in the seller authorizations,[36] or that the market power conditions of market-based rate authorizations are analogous to an implied contract between seller and buyer,[37] such that if a seller were found, after-the-fact, to have exercised market power, this would be deemed a violation of the seller's market rate tariffs and subject the seller to retroactive refund liability. They contend that the exercise of market power resulted in prices well above what would prevail in a workably competitive market, and, accordingly, prices charged by sellers during the summer of 2000 are contrary to the filed rate authorizations, and refunds should be ordered.[38]

The parties further argue that the Commission may order retroactive refunds where the rates charged exceed the filed rate or for violations of the conditions of sellers' market-based rate authority. In support, they cite cases in which the Commission ordered: disgorgement of profits for a period prior to the initiation of the Commission's complaint as a sanction against a public utility that violated the standards of conduct that were contained in its market-based tariff; refunds for monies illegally recovered through a fuel adjustment clause; refunds when the utility charges impermissible costs through a filed formula rate; and disgorgement of some revenues resulting from a transaction that lacked necessary Commission authorization.[39]

Other parties assert that the rates charged this summer comport with the filed rate doctrine, that there is no evidence that sellers charged rates that were not in compliance with the tariffs on file, and that sellers must be able to rely on the finality of filed rates.

Commission Determination

We agree that the Commission may take retroactive action to address circumstances where a seller did not charge the filed rate or violated statutory or regulatory requirements or rules in applicable rate tariffs.[40] However, it has not been demonstrated that any conditions or limitations of sellers'

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[36] E.g., Comments of PG&E; Rehearing of PG&E.

[37] Comments of City of San Diego.

[38] These parties do not define a "fully competitive" or "workably competitive" market.

[39] E.g., Comments of PG&E, Oversight Board, City of San Diego, California Commission, SDG&E, County of San Diego; Rehearings of SDG&E, PG&E, Oversight Board.

[40] For example, in Washington Water Power Co., 83 FERC ¶ 61,282 (1998), the Commission imposed sanctions for violations by Washington Water Power Company (WWP) and its power marketer affiliate Avista Energy, Inc. (Avista), of Avista's market-based rate order, specifically the affiliate conduct, OASIS and Standards of Conduct requirements. Avista was required to disgorge its (continued...)

market-based rate tariffs have been violated. The conditions hypothesized by the parties are not evident from the market-based rate schedules or our orders. Thus, there is no basis for finding that the sellers acted inconsistently with Commission-filed tariffs or with specific requirements in their filed rate authorizations. To the extent the Commission found that changed conditions in California created the opportunity for unjust and unreasonable rates, it remedied those problems prospectively. If it finds that refunds are appropriate, it can order refunds in accordance with the RFA refund effective date.

iii. Whether Sellers' Market-Based Rate Authorizations Were Provisional, Making the Rates Being Charged Subject to Retroactive Adjustment

Comments

The California Commission argues that the Commission may order refunds without violating the filed rate doctrine or the corollary rule against retroactive ratemaking if buyers and sellers were on notice that the rates being charged were "provisional," and might be subject to adjustment in the future. It argues that the Commission's early California electric restructuring orders contained qualifications that indicate that these decisions were provisional, and which warn that the structure and dynamics of the markets and their resulting rates were subject to adjustment or revision. It cites the November 1996 order (authorizing the establishment of the PX and the ISO) as characterizing the Commission's determination as "conditional" and "preliminary." See PG&E, et al., 77 FERC ¶ 61,204 at 61,793 (1996). It also cites the October 1997 order authorizing the PX and the ISO to commence operations, PG&E, et al., 81 FERC ¶ 61,122 at 61,435 (describing such authorization as "interim" and "conditional"); the December 1997 order authorizing the transfer of operational control of jurisdictional facilities, PG&E, et al., 81 FERC ¶ 62,210 at 64,473 (expressly reserving the right to "place further conditions on the transfer for good cause shown."). Thus, according to the California Commission, there was nothing certain on which buyers and sellers could have justifiably relied. Accordingly, there was no predictability as to what rates were being protected by the filed rate doctrine and rule against retroactive ratemaking.[41]

Oversight Board argues that the controversy over the high prices during the spring and summer of 2000 effectively put sellers on notice that their rates would be challenged, i.e., no reasonable seller would believe that their rates would go unchallenged.

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[40](...continued)
profits from the power sale at issue, and Avista's market-based rate authority was suspended prospectively for six months with respect to any power sale requiring the use of WWP's transmission system.

[41] See also Comments of PG&E, SDG&E.

Commission Determination

While it is correct that the Commission issued conditional orders on the restructuring and indicated that future changes might be made, the conditions went to the restructuring and the market rules, which were at that time not entirely finalized and were being implemented in phases. The Commission did not make changes to the individual sellers' market rate authorizations. The individual market-based rate applications were not made subject to a retroactive refund obligation when accepted, and the applicants had no reasonable expectation of such an obligation.[42] The orders give no indication that the Commission would consider retroactively changing rates. The conditions in the authorizations were very explicit, and indicated only that the Commission would revoke market rates if the seller acquired market power, not that it would retroactively change the rates.[43] Further, nothing in the restructuring or market rule orders indicates that the Commission was placing such a condition on sales into the ISO or PX.

Moreover, the mere existence of uncertainty or expectation of future controversy concerning sellers' rates would not serve to establish a de facto refund effective date for purposes of retroactive refunds. As discussed above, the establishment of a refund effective period is governed by the statute. As the instant matter arose from a complaint under section 206, we must look to that provision. Its terms specifically provide that the refund effective date is triggered by the filing of a complaint or the initiation of an investigation by the Commission. Section 206 does not provide for constructive notice. The refund effective date of October 2, 2000 is consistent with the statutory framework.

iv. Section 309 Authority

Comments

Several parties argue that there is substantial evidence that sellers were unjustly enriched by ISO and PX prices above competitive levels because sellers exercised or benefitted from the exercise of market power. They cite the Staff Report and the market monitoring reports prepared by California's independent market monitors.[44] They argue that the Commission has broad authority under section 309 of the FPA to restore the status quo and prevent unjust enrichment. In effect, they argue

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[42]By comparison, with respect to costs collected through fuel adjustment clauses, acceptance of Commission authority to adjust such charges after-the-fact is a condition of acceptance of the fuel adjustment clause filings.

[43]E.g., Louisville Gas and Electric Company, 62 FERC ¶ 61,016 at 61,143 n. 15 (1993).

[44]See, e.g., Comments of SoCal Edison, citing the study attached as Exh. A to its comments (Paul Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000" (Nov. 21, 2000)).

that section 309 gives the Commission retroactive refund authority for past unjust and unreasonable rates. They cite Niagara Mohawk Power Corp. v. FPC, 379 F.2d 153, 158 (D.C. Cir. 1967) (upholding decision to backdate a hydro license, and thus require back payments from a licensee who had failed to obtain its license prior to constructing hydro facilities); Mesa Petroleum Co. v. FPC, 441 F.2d 182 (5th Cir. 1971) (requiring a gas supplier to pay a purchaser the difference between what the purchaser would have paid under its contract with the supplier and the amounts it actually had to pay for replacement gas when the supplier abandoned the contract without Commission approval); and Louisiana Public Serv. Comm'n v. FERC, 174 F.3d 218, 224 n.6 (D.C. Cir. 1999) ("[t]he Commission's authority to order refunds of amounts improperly collected in violation of the filed rate derives from FPA § 309."). These parties urge the Commission to use FPA section 309 to order equitable relief that requires sellers to repay buyers the profits above competitive levels that the sellers received as a result of the exercise of market power.[45]

Oversight Board further asserts that section 4(i) of the Communications Act is analogous to section 309 of the FPA and that a court interpreted section 4(i) as conferring upon the Federal Communications Commission (FCC) authority to order retroactive refunds, even though sections 204 and 205 of the Communications Act, which it states are analogous to sections 205 and 206 of the FPA, do not authorize the FCC to order retroactive refunds.

SDG&E argues that the imposition of sanctions by the Commission may provide the only means to remedy abuses of market power by sellers. It expresses concern that courts may rule that antitrust claims and state law claims alleging injury due to unlawfully high prices – even if those prices are shown to have resulted from price-fixing collusion by sellers – would be preempted by the filed rate doctrine. It asserts that the Commission should investigate whether, and which, sellers have engaged in manipulative conduct including, but not limited to, the submission of phantom schedules to create apparent transmission congestion, the export and later re-importation of power to evade PX and ISO price caps, and the aggregation of significant amounts of supply from multiple sources by one scheduling coordinator for composite bidding in the wholesale markets. According to SDG&E, sellers who engage in such market abuse should be sanctioned by disgorgement of profits that resulted from such abuse.

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[45]Comments of PG&E, SoCal Edison; Rehearings of SDG&E, PG&E. SoCal Edison cites Order No. 637-A, in which the Commission expressly did not make natural gas transportation rates subject to refund because it could rely on its authority to afford relief pursuant to section 16 of the Natural Gas Act (NGA), which is analogous to section 309 of the FPA. See Regulation of Natural Gas Transmission Services and Regulation of Interstate Natural Gas Transportation Services, FERC Stats. & Regs. ¶ 31,091 (2000), order on reh'g, 91 FERC ¶ 61,191 (2000), appeal pending sub nom. Process Gas Consumers v. FERC, No. 00-1217 (D.C. Cir. filed May 26, 2000). SoCal Edison argues that the Commission could apply section 309 similarly in this case.

Oversight Board argues that the Commission's failure to address the legal issue of refund authority for the period prior to October 2, 2000 creates uncertainty and prevents resolution of the issue on appellate review.

Commission Determination

The remedial authority under section 309[46] is designed to fill in gaps where the FPA is silent, not to rewrite the explicit Congressional delegations of authority and explicit limitations on that authority. Section 309 and similar provisions "authorize an agency to use means of regulation not spelled out in detail, provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act." Niagara Mohawk, 379 F.2d at 158. Here, as we have reiterated, Congress explicitly delineated the extent of our refund authority under FPA sections 205 and 206. We do not read section 309 to permit us to go beyond that delegation.

Courts interpreting FPA section 309, and its counterpart NGA section 16, have indicated that "[b]oth sections are of an implementary rather than substantive character. . . . These sections merely augment existing powers conferred upon the agency by Congress, they do not confer independent authority to act." New England Power Co. v. FPC, 467 F.2d 425, 430-31 (D.C. Cir. 1972), aff'd, 415 U.S. 345 (1974).[47] Contrary to what the parties here seem to suggest, section 309 is not an independent source of authority that allows the Commission to expand its authority beyond that allowed in its governing statutes:

> The substantive provisions of the [NGA] contemplate certain procedures, as incident to the functions provided. The range of permissible procedures must be derived from these sections, sections like section 4 and 5 of the [NGA], and the functions they describe. Section 16, which uses a broad generality of "necessary and appropriate" that is not rooted in a function, cannot enlarge the choice of permissible procedures beyond those that may fairly be implied from the substantive sections and the functions there defined.

Mobil Oil Corp. v. FPC, 483 F.2d 1238, 1257 (D.C.Cir. 1973). The parties here seek not to introduce new procedures under FPA section 309, but to enlarge the substantive refund limitations in section 206 by expanding the refund period. If section 309 cannot be used to enlarge the permissible

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[46] FPA section 309 states in pertinent part: "The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this Act."

[47] Accord, e.g., McCombs v. FERC, 705 F.2d 1177, 1184-85 (10th Cir. 1980); Murphy Oil Corp. v. FPC, 431 F.2d 805, 810 (8th Cir. 1970).

procedures under the FPA, as Mobil found, then it surely cannot be used to expand the substantive provisions of the Act.

Oversight Board's reliance on New England Telephone & Telegraph Co. v. FCC[48] is misplaced. Although the Communications Act ("CA") contains similar provisions to FPA sections 205, 206, and 309, the statutory language differs in several respects as does the underlying regulatory approaches of the two Acts. The FCC in that case addressed different circumstances from those we face, in particular in that case the FCC used its powers to "prescribe rates of return," rather than to prescribe overall rates.[49] That prescription was upheld under CA section 4(i), analogous to FPA section 309, despite a finding that "[CA] section 205 does not authorize the Commission to prescribe rates of return," Nader, 520 F.2d at 203, as being consistent with the purposes of CA section 205. Id. at 204-05.

Importantly for this question, at the same time it prescribed a rate of return, the FCC stated that "the filing of a tariff designed to produce a rate of return in excess of [the allowed amount] is prima facie unlawful." Id. at 205 n. 25. This, the Court stated, meant "the Commission retains full latitude to order refunds on all other grounds," except that the allowed rate of return was too high. Id. Subsequently, when the FCC found that AT&T had earned a rate of return in excess of the allowed amount and ordered refunds, the court upheld this determination as "a straightforward and legitimate means for the Commission to enforce its 1976 rate-of-return prescription."[50] The Court found that this did not represent retroactive ratemaking "because the carriers' obligations were set prospectively in 1976, when the Commission forbade AT&T from earning more than 10%," the allowed rate of return.[51] As the FCC had set the 1976 rate of return prescription under its CA section 4(i) authority, it "properly exercised its authority under section 4(i) to remedy the violation by ordering rate reductions in the amount of AT&T's excessive earnings in 1978." Id. at 1109.

There is no parallel in the instant case. The Commission did not use its FPA section 309 power to establish individual market pricing authorizations. Nor did it set an objective standard against which market pricing standards would be measured or indicate that any price above that standard would be considered prima facie excessive. Thus, none of the elements that allowed the FCC to use its CA section 4(i) power to order refunds are presented here. Consequently, use of FPA section 309 as a means now to order retroactive refunds cannot be justified in face of the statutory limitations found in section 206.

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[48]826 F.2d 1101 (D.C. Cir. 1987), cert. denied, 490 U.S. 1039 (1989).

[49]826 F. 2d at 1109-10 and 1104-05; Nader v. FCC, 520 F.2d 182, 204 (D.C. Cir. 1975).

[50]See 826 F.2d at 1111.

[51] Id. at 1108.

c. Equitable Relief

PG&E proposes that, as an equitable alternative to price adjustments and refunds for the past period, the overcharges occurring prior to October 2 be quantified and amortized over a period of time, with the costs to be recovered from power sellers in California through an adjustment to their future bids in the ISO and PX markets. PG&E maintains there are precedents in the gas and electric industry for doing so. PG&E notes that the Commission's restructuring of the natural gas pipeline and electric industries permitted recovery of costs resulting from a fundamental change in market rules and regulatory policies. According to PG&E, a finding that the overcharges of the summer relate to flawed market rules and regulatory policies rather than tariff violations makes it equally appropriate that there be recovery of the unjustly incurred costs for buyers of power in California. It asserts that the profound changes in industry rules, brought on by the fundamental shift in regulatory policy in California and at the Commission, required that the California IOUs buy power on the volatile spot market. They were required to participate in the new industry structure, and they have incurred unprecedented costs as a result, according to PG&E.

IEP contends that market participants cannot manage or hedge the risks associated with the November 1 Order's equitable solutions proposal and that the proposal only invites litigation and exacerbates uncertainty that will harm California. If the Commission retains the equitable solutions proposal, IEP argues that the Commission must clarify that it is a temporary transition device only and that it will end on a date certain and not be subject to reopening.

Commission Determination

The electric and gas restructuring cases cited by PG&E are different from this case. They involved a change in regulatory scheme and allowed utilities to recover costs incurred under the pre-existing regulatory scheme. Order No. 637-A, cited by SoCal Edison, is also different from this case, because the equitable relief provided for in the rule under section 16 of the Natural Gas Act pertains to remedies for specific violations. Similarly, other cases cited by the parties involved sanctions for violations of explicit statutory commands.[52]

2. Refund Liability Should Apply To All Sellers of Energy In California

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[52]Niagara Mohawk (constructing a hydro facility without a license), Mesa Petroleum (abandonment without prior Commission approval), and Louisiana Public Serv. Comm'n (collections in violation of filed rates).

The Commission has determined that all sellers of energy in the California ISO and PX spot markets should be subject to refund liability for the period beginning October 2, 2000.[53] We have decided to extend refund liability to public and non-public utility sellers based on our review of the controlling law, the involvement of both types of sellers in the California centralized ISO and PX spot markets, and the equities of the situation. Non-public utility sellers as well as public utility sellers of electric energy in those California markets contributed to and benefitted from the dysfunctions that offered the possibilities for the market abuse under certain conditions, on which the call for refunds are based. In these circumstances, as discussed below, we conclude that although we do not have direct regulatory rate authority over power sales by non-public utilities, we do have authority to order them to abide by the market rules we have established and to make refunds of unjust and unreasonable rates for sales pursuant to those market rules. Accordingly, PG&E's, SoCal Edison's, and SDG&E's requests for rehearing of the March 9 Refund Order seeking refund liability for non-public utilities will be granted.

a. Statutory Framework

Analysis of the Commission's authority begins, as it must, with the FPA statutory language. The refund obligations at issue relate to the sale of electricity for resale in the California ISO's and PX's interstate spot markets. The Commission's authority, under FPA section 201(b), encompasses "the sale of electric energy at wholesale in interstate commerce." In the restructured California market, all sales into the PX or ISO meet this definition. See also FPA § 201(b)(2) (defining wholesale sales). The wholesale sales of electricity here thus fall within the subject matter of the Commission's statutory authority.

The question at issue involves the interplay between that subject matter jurisdiction and the express limitations on FPA jurisdiction to public utilities. The Commission's authority under FPA section 206(a) is limited to rates "collected by any public utility for any . . . sale subject to the jurisdiction of the Commission." FPA section 201(d)(2)(f) provides that, except where specifically stated otherwise, no provision of Part II of the FPA applies to "the United States, a state or any political subdivision of a state, or any agency, authority or instrumentality of any one or more of the foregoing").

b. FERC Has Jurisdiction Over the Subject Matter of The Sales At Issue

[53] While the Commission in other orders and in other contexts has stated that it does not have jurisdiction over non-public utilities under sections 205 and 206 of the FPA, we have re-examined our authority in the particular circumstances presented here: a centralized single clearing price auction that sets wholesale prices for both public utilities and non-public utilities, pursuant to market rules set by this Commission and administered by public utilities subject to this Commission's jurisdiction (the California ISO and PX).

At issue is whether the Commission can assert jurisdiction over the California ISO and PX wholesale electricity markets in a manner that encompasses non-public utility sellers that are not subject to our direct jurisdiction under FPA section 206. Under the specific circumstances presented, we conclude that such jurisdiction may properly be asserted over non-public utility sellers of energy. Under the single price auction mechanism that operated in the centralized ISO and PX spot markets, all sellers agreed to accept the same clearing price for any given sale. From the time the Commission acted on SDG&E's complaint, all sellers into those markets were on notice that those clearing prices, and the market rules that set the clearing prices, were subject to change if they were found to be unjust and unreasonable. For example, the November 1 Order states: ". . . if the Commission finds that the wholesale markets in California are unable to produce competitive, just and reasonable prices . . . we may require refunds for sales made during the refund effective period."[54]

Our action here establishes a revised method for calculating the just and reasonable clearing prices to be applied in those markets for the period beginning
October 2, 2000. This is pursuant to the Commission's authority under FPA section 206 to fix the just and reasonable rate. Our action thus revises the market clearing prices that all market participants previously agreed to accept for their sales. In this context, we see no reason to treat non-public utility sellers differently, as they are receiving the same price, the just and reasonable market clearing price established pursuant to market rules approved by this Commission, that they expected to obtain for their wholesale sales into the centralized ISO and PX spot markets.

When faced with a similar question under the Natural Gas Act, the D.C. Circuit concluded that the Commission could exert rate authority over non-jurisdictional entities to fulfill its statutory responsibilities regarding the subject matter of its NGA jurisdiction. In United Gas Distribution Cos. v. FERC, 88 F.3d 1105 (D.C. Cir. 1996), local distribution companies and municipalities, both of whom are exempt from NGA jurisdiction, challenged application of FERC's open access rules to their release of their own capacity on a pipeline system. The court focused on the subject matter of the transaction, not the parties involved, to determine the Commission's authority to act. The court found that, notwithstanding the LDCs' exemption from the NGA, "the Commission's jurisdiction attaches to the subject of the capacity release transaction: interstate transportation rights." 88 F.3d at 1152. Further, the court found that exempting LDCs would allow them to engage in capacity release "without regard to the principles of open access and nondiscrimination that are at the heart" of the program. Id. That result would be "directly contrary to Congress' intent in enacting the [NGA]." Id. Consequently, the court found the Commission properly included LDCs within the regulatory plan to further the statutory goals.

Similarly, here, Commission jurisdiction attaches to the subject matter of the affected transactions: wholesale sales of electric energy in interstate commerce through a Commission-authorized and Commission-regulated centralized clearinghouse that set a market clearing price for all

[54]93 FERC at 61,370; see also December 15 Order, 94 FERC at 62,010-11 (same).

wholesale seller participants, including non-public utilities. Exempting transactions involving non-public utility sellers from refund scrutiny here would allow them to make such sales without regard to the just and reasonable standard that applies to the market clearing price administered by the ISO (and previously by the PX), and that pervades all Commission ratemaking policies.

It is noteworthy that California may not regulate out of state sellers and has declined to regulate California non-public utilities' sales in the California centralized ISO and PX spot markets. As a result, absent FERC jurisdiction, a regulatory gap for these sales could exist. Such a result could preclude us from protecting consumers from exploitation in these markets, one of our statutory objectives under the FPA.

For essentially the same reasons, the court in UDC found the Commission could require compliance with its capacity release regulations from municipalities.

> FERC may, consistent with the NGA, require municipalities to comply with its capacity release regulations . . . . FERC's transportation jurisdiction extends as a separate matter over capacity release given the involvement of interstate gas pipelines. The pipelines' role in capacity release is absolutely central, and the transaction itself controls access to interstate transportation capacity, entirely independent of the jurisdictional nature of the releasing and replacement shippers.

88 F.3d at 1154 (emphasis in original; footnotes omitted). The court also found "compelling" that prior to adoption of the Commission's capacity release program, neither jurisdictional nor non-jurisdictional entities could release capacity. Thus, as the Commission set up the program that benefitted both jurisdictional and non-jurisdictional parties, it could establish rules by which all parties must abide. Id.

Here, the central transactions, wholesale sales of energy in interstate commerce, were governed by FERC-approved rules and a FERC-jurisdictional ISO and PX. Those transactions thus fell within FERC's jurisdiction regardless of the jurisdictional nature of the sellers or buyers. Further, the centralized wholesale spot electricity markets operated by the California ISO and PX were established (and have been modified) subject to FERC review and approval. Because the market did not exist prior to FERC authorization, all those who participated in the market had to recognize the controlling weight of FERC authority. Moreover, it is fair that all those who benefitted from this market also bear responsibility for remedying any potential unlawful transactions that might have occurred in the market.

Non-public utility sellers in the California market entered into various arrangements that acknowledged the Commission's authority over the centralized transactions. For example, in Pacific Gas and Electric Co., et al., 82 FERC

¶ 61,326 (1998), many non-public utility sellers accepted a FERC-authorized, pro-forma Scheduling Coordinator Agreement. Id. at 62,283.[55] Among the obligations under the Agreement, parties agreed "to comply with the terms and conditions of the ISO Tariff and ISO Protocols." Id. For the PX, the Commission required that parties sign a FERC-authorized, pro-forma Participation Agreement. California Power Exchange Corp., 83 FERC ¶ 61,186 (1998). Against opposition, the Commission concluded that the Participation Agreement and "the services provided under the PX Tariff are jurisdictional." Id. at 61,771. The Commission indicated that the Agreement "is the contract under which the California PX provides these services to its customers" and, as such, could be required to be filed in accordance with FPA section 205(c). Id. A large number of non-public utility sellers executed the Participation Agreement. See, e.g., PX letter filing of January 25, 2001 (index of parties who executed the Agreement as of December 31, 2000).

Placing jurisdictional and non-jurisdictional sellers on the same footing for refund purposes promotes the underlying goals of the FPA. Under California's restructuring system, interstate, wholesale sales of electric energy were transacted largely through hourly single price auctions, which meant that all bidders into these spot markets received the same price for a specific sale. In fact, prior to Commission modification, California public utilities were required by California to transact exclusively through the PX under the mandatory buy/sell rule.

Consequently, if the price for a specific sale is found to be unjust and unreasonable, then all sellers who obtained that price received an unjust and unreasonable rate. To the extent the Commission determines refunds are an appropriate remedy for that sale, consumers can only be made whole by refunds from all sellers who received the excessive price.[56] As non-public utility sellers of energy and ancillary services accounted for up to 30 percent of all sales in the California centralized ISO and PX spot markets, excluding them from a potential refund remedy could have a serious detrimental effect on consumers.

3. Refund Liability Can Apply From October 2, 2000 Through June 20, 2001

The above discussion also largely disposes of any claim that the Commission is impermissibly applying refund liability to non-public utility sellers back to the October 2, 2000, refund effective date that we previously announced. Because refund obligations relate to factual issues concerning past

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[55] One such seller was City of Los Angeles, Department of Water & Power, whose Agreement was docketed as ER98-1934-000. Id.

[56] We note that non-public utilities (e.g., Turlock Irrigation District and the City of Burbank) are seeking refunds for what they perceive are excessive charges paid in these markets. Under the maxim that those who seek equity must do equity, McQuiddy v. Ware, 87 U.S. 14,19 (1873); In re Gardenshire, 209 F.3d 1145, 1152 n. 11 (9th Cir. 2000), it would only be fair that these same utilities be willing to pay refunds related to any excessive amounts they may have collected.

periods, their resolution is considered to be adjudication. Adjudications are generally given retroactive effect. See Harper v. Virginia Dept. of Taxation, 509 U.S. 86, 94-95 (1993)(referring to "the fundamental rule of retrospective operation that has governed judicial decisions for near a thousand years"). The Court has declined to accept equitable reliance as grounds for limiting the retroactive application of an adjudicatory decision. "The federal law applicable to a particular case does not turn on whether litigants actually relied on an old rule [or] how they would suffer from retroactive application of a new one." Id. at n.9 (citation and quotation marks omitted).

Of course, in the instant matter, as explained above, the non-public utility sellers were well aware that these transactions involved wholesale sales of electricity subject to FERC jurisdiction. These sellers had executed the pro forma agreements established by the Commission that indicated, in part, their willingness to comply with the terms of the FERC-jurisdictional ISO or PX tariffs. These factors undermine possible claims that non-public utility sellers of energy could reasonably have relied on their sales for resale of electricity into the centralized interstate California ISO and PX spot markets not properly being subject to FERC jurisdiction.

The Supreme Court's discussion of retroactivity arose in the context of judicial adjudication, but the same principles counsel strongly for like treatment in agency adjudications. See Southwestern Public Service Co. v. FERC, 952 F.2d 555, 563 (D.C. Cir. 1992) (indicating FERC "should take note" of recent Supreme Court case that "may forbid agencies to apply rules with selective retrospectivity.") (citation omitted). The D.C. Circuit also recently indicated that selective retroactivity[57] for remedial purposes "breaches the principle that litigants in similar situations should be treated the same, a fundamental component of stare decisis and the rule of law generally." Nat'l Fuel Gas Supply Corp. v. FERC, 59 F.3d 1781, 1789 (D.C. Cir. 1995)(citation omitted). Here, as discussed above, public utility and non-public utility sellers under the single price auction system used in the affected markets were similarly situated regarding the price they received for their sales for resale of electricity, and thus should be treated similarly in the consideration of whether refunds should be required.

The D.C. Circuit has, however, expressly declined to require that agency adjudications enforcing agency decisions apply retroactively. See, e.g., Power Corp. of America, 245 F.3d at 847. Instead, the court applies a five-part test for deciding if retroactivity is inappropriate. Williams Natural Gas Co. v. FERC, 3F.3d 1544, 1553-55 (D.C. Cir. 1993); see Retail Wholesale & Dept. Store Union v. NLRB, 466 F.2d 380, 390 (D.C. Cir. 1972)(one formulation of criteria). Under these criteria, our determination that non-public utility sellers of energy in the California market can be liable for refunds should apply retroactively.

The initial criterion asks whether the issue is one of first impression. We have no trouble finding that the instant question is, given that California was the first state to restructure its electricity market

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[57]That is, prospective application for some, and retrospective application for others.

and the Commission had never dealt with market-wide refunds in a single price auction for widespread centralized spot purchases of wholesale electricity in interstate commerce. The next criterion looks to whether Commission action seeks to fill a void in an unsettled area of the law. For the same reasons mentioned in the first criterion, this factor weighs in favor of retroactivity. The Commission seeks to redress a previously unencountered situation in a manner that furthers the underlying purpose of the FPA.

The third criterion asks the extent to which parties relied on the old rule. Here, there was no old rule to apply to the precise situation. But, in any event, non-public utility sellers should have recognized their sales for resale into the centralized ISO or PX spot markets were the subject of FERC jurisdiction and scrutiny. Among other things, FERC's investigation into the ISO and PX market practices and rules, with indications in the August 23 Order that possible remedies included changes to the market clearing price mechanisms and refunds, should have alerted non-public utility (as well as public utility) sellers of FERC's authority over their sales in those markets. Moreover, those sellers signed FERC pro forma agreements that indicated their willingness to comply with FERC-authorized tariffs.

The fourth and fifth criteria also weigh in favor of retroactivity. Ordering non-public utility sellers to refund amounts received in excess of just and reasonable rates does not impose an unfair burden, but merely place those sellers in the same position as public utility sellers. Finally, the statutory interest in protecting consumers against exploitation is furthered by subjecting non-public utility sellers, who represent up to 30 percent of all sales into the California ISO and PX spot markets during the applicable time period, to possible refund liability to the same extent as public utility sellers. Otherwise, consumers will not be made whole for any prices found to be excessive. Moreover, fundamental fairness dictates that in the context of a single price auction, where all bidders received the same price for a specific sale, all those parties should now bear the responsibility of refunding any amounts found to be unjust and unreasonable.

In short, the balance tips decidedly in favor of retroactive application of refund liability to October 2, 2000, for all sellers in the California ISO and PX spot markets.

4. DWR Transactions

By motion dated March 1, 2001, the Oversight Board requested clarification and extension of the December 15 Order, arguing that DWR bilateral contracts should be subject to refund. These contracts became an issue when, on January 17, 2001, the Governor of California issued an emergency proclamation giving DWR authority to enter into arrangements to purchase power. DWR began purchasing under this authority the next day. DWR has purchased substantial amounts of energy in the ISO's Imbalance Energy market and is in the process of executing long-term purchases. The California Commission and SoCal Edison supported the motion. Numerous other parties opposed the motion, contending that the relief sought would be inconsistent with the objectives of the December 15 Order and because the proposed changes to parties' market-based rate authorizations would have to be considered under FPA section 206.

Subsequently, a number of parties filed comments on the Chief Judge's Report arguing that the DWR bilateral contracts should remain outside the scope of the Commission's refund orders given that these transactions represent bargained-for exchanges between willing buyers and sellers (with DWR picking and choosing the transactions it wanted, exercising discretion and exhibiting price response).[58]

We believe imposing after-the-fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified. This is particularly true in the instant proceeding when the Commission consistently encouraged California load serving entities to acquire a balanced portfolio of short, medium and long-term contracts. Expanding the scope of transactions subject to refund over the period October 2, 2000, through June 20, 2001 to include transactions outside the ISO and PX centralized markets would simply hinder the ability of parties to enter into new bilateral contracts. Accordingly, the Commission will deny the Oversight Board's motion.[59]

Further, we note that while DWR is a market participant that competes with other suppliers and purchasers of energy and ancillary services in the ISO markets, unlike other market participants, DWR has had access to the ISO's control room and associated written materials, visual observations, and oral statements regarding the ISO's markets, systems, operations and activities.[60] This has provided DWR a competitive advantage in entering into its bilateral contracts. In addition, by voluntarily entering into bilateral transactions outside the ISO and PX, DWR made a conscious decision to forego the refund protection that the Commission provided for purchases through the ISO and PX. Thus, there is no equitable rationale that supports making DWR's bilateral contracts subject to refund.

The Commission will issue a further order concerning the standards of conduct between the ISO and DWR in Docket No. ER01-889.

5. OOM Transactions

Several parties request clarification that the ISO's out-of-market (OOM) purchases are subject to refund. We grant this clarification. As we stated previously in our November 1 Order, "the electric market structure and market rules for wholesale sales of electric energy in California are seriously

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[58] See Statement of the Undersigned Generators to the Chief Judge, dated July 9, 2001, at 8.

[59] If DWR (or any other party) believes any of its contracts are unjust and unreasonable, it may file a complaint under FPA section 206 to seek modification of such contracts.

[60] See Confidentiality, Non-Disclosure and Use of Information Agreement dated January 24, 2001 filed as Attachment G by the ISO on June 19, 2001 in Docket No. ER01-889-005.

flawed and [ ] 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."[61] The order noted 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."[62] These statements are most true with respect to the ISO's daily OOM purchases for obtaining the resources it needs to reliably operate the grid.

As stated in the August 23 Order, if there is insufficient supply in the ISO markets, then the ISO must procure additional supplies at the last minute with OOM purchases in order to meet its needs for the operating day. Historically, the ISO procured on a daily basis only the resources needed for the operating day. Not only did this procurement practice put pressure on the grid operator to secure needed resources at the last minute, but the practice was uneconomical. Because the ISO is the supplier of last resort for these services, when OOM calls are made, suppliers realize that the ISO is in a must-buy situation. For this reason, we directed the ISO to immediately institute a more forward approach to procuring the resources necessary to reliably operate the grid.[63]

To the extent the ISO made spot market OOM purchases (i.e., 24 hours or less and that were entered into the day of or day prior to delivery), such purchases are no different than purchases through its markets. Both types of purchases are made by the ISO in order to procure the resources necessary to reliably operate the grid. Therefore, we clarify that spot market OOM transactions are subject to refund and subject to the hourly mitigated price established in the ordered hearing. The hourly price will establish the maximum price with refunds for transactions over this level.

6. Sales Made Pursuant to DOE Orders

PPL Montana, PPL EnergyPlus, and PPL Southwest Generation Holdings (PPL Parties) state that in the exercise of his authority under section 202(c) of the FPA, the Secretary of Energy (Secretary), in a series of orders directed PPL Montana, among others, to make the necessary arrangements to supply energy as requested by the California ISO. PPL Parties maintain that such sales made pursuant to the orders issued by the Secretary under this authority should not be subject to refund because they were not made pursuant to section 205 of the FPA. The ISO maintains that sales made pursuant to section 202(c) should be subject to refund.

[61] 93 FERC at 61,349.

[62] Id. at 61,350.

[63] 92 FERC at 61,608.

PPL Parties state that section 202(c) has its own mechanism for determining sales prices. Under the section, sales are to be made at an agreed upon price. Only if price and terms cannot be agreed to in accordance with the existing regulations, the terms are to be immediately prescribed by the Secretary and the price referred to this Commission for subsequent determination of a rate it determines is "just and reasonable."[64] According to PPL Parties, there is nothing in section 202(c) that authorizes the payment of refunds or the redetermination of sales prices where there has been mutual agreement.

Furthermore, PPL Parties state that the Secretary specifically directed in his orders that "the terms of any arrangement made between the entities subject to this order and the California ISO pursuant to this order are to be agreed to by the parties." Therefore, they assert that any action by the Commission to alter the terms of agreements voluntarily reached by ordering refunds would be inconsistent with the Secretary's mandate.

We agree that rates for transactions entered into under section 202(c) in compliance with the Secretary's orders are outside the scope of this proceeding. The Secretary has not referred any sales to this Commission for a rate determination; if any had been referred here, they would have been reviewed in a separate proceeding.

7. PG&E Bankruptcy

We note that on April 6, 2001, PG&E filed for Chapter 11 bankruptcy protection. Although the Bankruptcy Code provides that the filing of a bankruptcy petition automatically stays certain actions against the debtor,[65] the Code also provides an exception from this automatic stay for:

> An action or proceeding by a governmental unit . . . to enforce such governmental unit's or organization's police and regulatory power, including the enforcement of a judgment other than a money judgment, obtained in an action or proceeding by the governmental unit to enforce such governmental unit's or organization's police or regulatory power.[66]

The Commission has found in the past that actions taken under the authority granted it by the Federal Power Act and the controlling regulations fit within this exception, and, therefore, are exempt from the automatic stay provision.[67] In the instant matter, we are exercising our regulatory power

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[64] 10 C.F.R. § 205.376 (2001)

[65] 11 U.S.C. § 362(a)(1) (1994 & Supp. 2000).

[66] 11 U.S.C. § 362(b)(4) (1994 & Supp. 2000).

[67] See Virginia Electric and Power Company, 84 FERC ¶ 61,254 (1998); and Century Power (continued...)

under section 206 of the Federal Power Act as permitted by section 362(b)(4) of the Bankruptcy Code to issue an order that does not threaten the bankruptcy court's control over the property of the bankruptcy estate.
As this order establishes the formula for refunds but does not impose any monetary obligation on PG&E, it has no effect on PG&E's bankruptcy estate.

C. Refund Calculation Methodology

We will adopt the recommendations of the Chief Judge, as modified below, and apply the methodology set out in the June 19 Order from the October 2, 2000, refund effective date, through June 20, 2001 to determine the amount of refunds due to the customers in the ISO and PX spot markets. As the Chief Judge recognized, the methodology in the June 19 Order must be modified in order to be applied to the period October 2, 2000, through June 20, 2001. In this respect, we will direct the ISO to make the modifications discussed below to the methodology presented in the June 19 Order, for the purposes of developing a factual record for analyzing these markets during the refund period.

The scope of the June 19 price mitigation extends to all spot market hours. Applying this to the period October 2, 2000, through June 20, 2001, will enlarge the number of hours that the March 9 Refund Order made subject to refund for the period January 1 through May 28, 2001. Accordingly, we will grant the requests for rehearing of the March 9 Refund Order that seek to increase the hours of price mitigation for this period. In addition, we note that the June 19 Order mitigates prices during all hours effective as of June 21, 2001. This leaves a gap from May 29 through June 20, 2001, when price mitigation only applied to periods of system emergencies. In order to maintain a consistent approach during all periods of time, the Commission will require application of the refund calculation methodology discussed below to non-reserve deficiency hours from May 29 through June 20, 2001. Transactions that occurred during reserve deficiency hours in this period, already mitigated as a result of the April 26 Order, will not be affected.

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[67](...continued)
Corp., 56 FERC ¶ 61,087 (1991). The Commission conclusion on this matter is consistent with judicial precedent regarding the scope of the exemption to the automatic stay. E.g., Board of Governors of the Federal Reserve System v. MCorp Fin., Inc., 502 U.S. 32 (1991); SEC v. Brennan, 250 F.3d 65 (2nd Cir. 2000); NLRB v. Continental Hagen Corp., 932 F.2d 828 (9th Cir. 1991); United States v. Commonwealth Cos. Inc. 913 F.2d 518 (8th Cir. 1990); NLRB v. Edward Cooper Painting, Inc. 804 F.2d 934 (6th Cir. 1986); Penn Terra Ltd. v. Dept. of Environmental Resources, 733 F.2d 267 (3rd Cir. 1984); In re Pacific Gas and Electric Co., et al., No. 01-30932 (Bankr. N.D.Cal. June 1, 2001)(finding the regulatory exception applies to a California Commission decision affecting PG&E's financial condition); see generally 3 Collier on Bankruptcy § 362.05 (15th ed. rev. 2000).

The June 19 Order established a mitigated price based upon the marginal cost of the last unit dispatched to meet the load in the ISO's real-time market. The June 19 Order also established a "must offer" requirement that each generator offer all available and uncommitted capacity in real-time. The ISO, County of Los Angeles, California Commission, SDG&E, SoCal Edison, and the Oversight Board (collectively, California Parties) argue that in applying the June 19 Order for the period October 2, 2000 through June 20, 2001, the methodology must include a simulation of the must offer requirement (an assumed economic dispatch). This modification to the actual data lowers the heat rate for establishing the market clearing price because it assumes that all generation that was not dispatched was really available, and that more imports were available than the actual quantities. The California Parties allege that the use of historical dispatch would yield higher prices than the prices resulting from using an assumed economic dispatch, and higher prices would reward the exercise of market power.

We did not institute the must offer requirement or the marginal bidding requirement until May 28, 2001, and it is unreasonable to re-create the markets to apply such requirements for the period October 2, 2000 through June 20, 2001. Generators actually dispatched in the markets during these periods have specific marginal costs that are reasonably recovered under our methodology. The end result of using an assumed economic dispatch (prices lower than the actual marginal costs of the last generator dispatched) unfairly punishes the very generators that helped keep the lights on in California. Therefore, we will require that the ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real-time the maximum heat rate of any unit dispatched each hour in the real-time imbalance market for the period October 2, 2000 through May 28, 2001. [68] This should address the concerns of numerous commenters that application of the June 19 methodology from October 2, 2000 forward, particularly with respect to marketers that are price takers, would be confiscatory.

The June 19 Order also established a mitigated price for hours of non-reserve deficiency at 85 percent of the market clearing price established during the last Stage 1 reserve deficiency. The Chief Judge ruled that, on a retroactive basis, the 85 percent maximum price for non-reserve deficiency periods could distort re-creation of a competitive market. Most commenters, including California Parties, Southern California Water Company and Dynegy, agree that the methodology for calculating refunds should not incorporate this element and instead should calculate a competitive price for every hour of the period in question. California Parties argue that including the 85 percent formula in calculating refunds would provide sellers with an unjustified off-peak premium. Due to the support for

[68]For the periods when the ISO instituted 10-minute dispatch protocols, we direct the ISO to take the average of the maximum heat rates for the six 10-minute periods in order to develop a market clearing price for application in the hourly auctions (including the PX markets). For the purposes of rerunning the settlement/billing process in the imbalance market, we direct the ISO to substitute the revised market clearing prices calculated for each 10-minute period in its settlement software.

this modification and because no party has raised a legitimate concern over the Chief Judge's rationale, we will adopt his recommendation.

In support of the recommendation to use the daily spot market price for gas, the Chief Judge relied on record evidence that the energy sales at issue were made with spot gas purchases. PG&E maintains that there is no need to alter the treatment of gas costs in the June 19 Order (i.e., averaging the bid-point of the monthly bid-week prices reported by Gas Daily for three spot market prices reported for California). Moreover, PG&E contends that the use of spot gas prices is unreasonable as there have been large differentials between such prices and average costs.

We note that PG&E has not refuted the underlying record evidence relied upon by the Chief Judge in making his recommendation to use daily spot purchases (i.e., that such sales were typically made with gas purchased in the spot market).[69] In addition, we note that spot purchases have traditionally been used to calculate the replacement cost of fuel. Given that the gas treatment in the June 19 Order was intended to address and influence purchasing decisions for prospective sales, there is simply no support for requiring a similar treatment for retroactive application to past sales.

Mirant argues that the use of the Malin delivery point for an input for northern California suppliers is inappropriate because this index price is less than the PG&E City Gate price. According to Mirant, using an average of the two indexes will not reflect the actual fuel cost to the generators in northern California. If sellers in California, such as Mirant, 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 period and including the refund period.

A number of Marketers and public utilities outside of California state that their purchased power costs, which may be higher than the hourly price calculated under the methodology adopted by the Commission, should be used to offset any potential refunds. Consistent with our prospective ruling in the June 19 Order, we will not allow such a showing for the period October 2, 2000 through June 20, 2001. We note that the public utilities outside of California typically entered into must-take purchase power contracts for weekly, monthly or longer periods. Their short-term purchases were made in order to either meet minimum reserve requirements or to supply their native load. To the extent these public utilities' total resources, both owned and purchased, temporarily exceeded their actual total system load, the surplus was available as opportunity sales in the spot markets including the

[69] Prior to market-based rates, economy sales (or sales from capacity available after a public utility's requirements and other firm customers were served) were the equivalent of spot market sales. Economy sales were priced at incremental or marginal cost, which was based on a fuel charge equal to the replacement cost of fuel. See, e.g., Indiana & Michigan Electric Company, et al., 10 FERC ¶ 61,295 (1980).

ISO and PX spot markets. Because the purchased power costs of these utilities were sunk costs similar to their investment in their own plant, any revenues generated from off-system sales at market based rates reduces their initial purchase power costs to serve their native load. Even the lower mitigated hourly prices determined in the hearing will subsidize these public utilities' overall cost of providing native load service. Finally, as noted in the June 19 Order, 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.

Several sellers support the use of separate gas prices for northern and southern California. The California Parties object to any change in the gas prices used in the June 19 Order, stating that it is unclear how two gas prices could be used under the June 19th methodology. Reliant adds that the methodology should maintain a single price auction mechanism for determining refunds instead of separate northern and southern market clearing prices. We find the approach suggested by the Chief Judge to be a workable addition to the June 19 Order methodology consistent with the determination of the actual running costs of the marginal unit. We will adopt the method proposed by the Chief Judge and direct the ISO to apply the appropriate gas price once the marginal unit is determined. If that marginal unit is located in the North of Path 15 (NP15) zone, then the ISO should calculate the market clearing price by using the average daily spot gas price for PG&E Citygate and Malin. If that marginal unit is located in the South of Path 15 (SP15) zone, the ISO should calculate the market clearing price by using the average daily spot gas price for Southern California Gas large packages. We clarify that these inputs are to be used to calculate a single clearing price.

While we are adopting the Chief Judge's recommendation to use daily spot gas prices and the three delivery points as reported by Financial Times Energy's "Gas Daily," we will adopt one modification based on comments filed by Intelligence Press, Inc. (Intelligence Press). Intelligence Press states that the Commission has in the past used a composite of published market prices and notes that using multiple sources addresses a number of concerns including reducing the effect of errors that might occur in gathering and reporting the spot price data. We believe that these are valid points. Accordingly, the gas inputs recommended by the Chief Judge should be based on the simple average daily spot price as reported by Gas Daily, NGI's Daily Gas Price index and Inside FERC's Gas Market Report. The last published gas prices should be used in calculating the refund price for the days that these publications are not published (weekends and holidays). [70]

The June 19 Order also established an O&M adder of $6/MWh to be included in the calculated market clearing price. The Chief Judge recommended the same adder be included in the

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[70] We note that NGI's Daily Gas Price index and Inside FERC's Gas Market Report did not have a listing for Southern California Gas Large Packages during the refund period. Therefore, we instruct the ISO to use the Financial Times Energy's "Gas Daily" for calculation of the southern gas price during the refund period.

methodology for calculating refunds. No parties commented on this adder and we therefore adopt its use in the methodology.

The Chief Judge recommended that the methodology establish a separate expense category for demonstrable emissions costs that sellers may subtract from their respective refund calculations, consistent with the mitigation methodology established in the June 19 Order. Reliant maintains that NOX costs and other environmental mitigation fees represent costs that a generator actually incurred in producing energy and, as such, should be included in the calculation of cost for the marginal unit. Although we note that the inclusion of emissions costs in the calculation of the costs for the marginal unit is sound economic theory, we find that in practice, actual emissions costs vary by location, time period, and duration. We find that the incorporation of such costs, which have not been demonstrated to be hourly costs, in the context of calculating hourly marginal costs for the purposes of establishing refund liability, would present an insurmountable burden. We find that allowing full recovery by the generators of all of their demonstrable emissions costs incurred during the refund period is appropriate. Because the emissions cost will not be included in the revised market clearing price, we direct all sellers to submit during the hearing their emissions costs incurred during the refund period for subtraction from their respective refund liabilities.

California Parties object to the inclusion of a ten percent creditworthiness adder, stating that sellers' actions in charging high prices forced SoCal Edison and PG&E to lose their credit rating, and that a credit adder would reward them for these actions. Sellers support the creditworthiness adder although they state that ten percent could be insufficient to accurately reflect the credit risk associated with making sales into California during the refund period. PPL Montana states that sellers making the sales for which refunds are contemplated not only were deterred from obtaining appropriate credit guarantees, but have experienced actual harm in the form of non-payment.

We find that the inclusion of a creditworthiness adder in the methodology to determine refund liability is appropriate and necessary. One result of parties' failure to reach settlement in this proceeding is that payment of overdue amounts has not been assured. The methodology we set forth will determine the just and reasonable rates that buyers will pay, but it cannot provide assurances that buyers, one of which is currently embroiled in bankruptcy proceedings, will pay the full amounts due. Therefore, we will adopt the recommendation of the Chief Judge that the 10 percent adder should be included in the market clearing price. At this time we will limit the adder to all transactions that occurred after the downgrade of SoCal Edison and PG&E's bond ratings on January 5, 2001.

Once the ISO has calculated the hourly market clearing prices for the refund period, this data should be used by both the ISO and PX to rerun their settlement/billing processes and all penalties. These revised settlements should be submitted to the Administrative Law Judge and parties should use this information to form the basis of any offsets (i.e. the amounts to be refunded against the payments past due). We direct the Administrative Law Judge to certify this information, in its entirety, to the Commission.

California Parties support the calculation of interest against refunds and maintain that Commission precedent requires an interest calculation. Sellers believe that if interest charges are assessed that they should be assessed symmetrically to refunded amounts and to amounts past due. We will direct the calculation of interest on both refunds and receivables past due, pursuant to the methodology for the calculation of interest under Section 35.19a of the Code of Federal Regulations.

D. Evidentiary Hearing Proceeding

The Chief Judge's Report stated that the differences between what the purchasers and the sellers in the California market believe are owed in refunds raise material issues of fact and recommended an evidentiary hearing be ordered in this proceeding. Several parties commented that there were no issues of material fact because there had been no offer of settlement requiring litigation, and urged the Commission to continue the settlement process.[71] Others commented that the Commission has sufficient record evidence to support a refund remedy and believed there is no need for a hearing to determine the methodology.[72] Still others supported the Chief Judge's conclusion but recommended various methods to limit the scope of further proceedings.[73]

The Commission agrees that, despite the voluminous record accumulated in this proceeding to date, material issues of fact remain that prevent the Commission from ordering refunds at this time. We believe that the most orderly and expeditious method of determining what refunds are owed will be to convene an evidentiary hearing before an Administrative Law Judge. Accordingly, the Commission will establish an evidentiary hearing to further develop the factual record so that the refund methodology presented in this order may be implemented, to be convened by Administrative Law Judge Birchman. The scope of the hearing will be limited to the collection of data needed to apply the refund methodology prescribed herein; we will direct Judge Birchman not to entertain any arguments relating to the methodology or the scope of transactions subject to refunds, except as otherwise indicated in this order.

In order to develop the factual record , the ISO will be directed to provide Judge Birchman with a re-creation of the mitigated prices that result from using the methodology described herein for every hour from October 2, 2000 through June 20, 2001, within fifteen days of the date this order is issued. The ISO and PX are further directed to rerun their settlement/billing process as described above and provide this data to Judge Birchman.

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[71] See, e.g., comments of Pinnacle West Companies, Public Service Company of New Mexico.

[72] See, e.g., comments of PG&E, California Parties.

[73] Comments of Reliant, Mirant.

We will direct Judge Birchman to make findings of fact with respect to: (1) the mitigated price in each hour of the refund period; (2) the amount of refunds owed by each supplier according to the methodology established herein; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the ISO, the investor owned utilities, and the State of California. We will require the judge to certify findings of fact to the Commission, without an initial decision, by no later than 45 days after the date that the ISO provides this data.

E. Pacific Northwest Proceeding

The Chief Judge noted that there was little time to address the issues raised by the Pacific Northwest Parties. Moreover, these parties did not have data on what they claim they were owed, nor on an amount of refunds due them. The Chief Judge requested comments on the necessity of convening subsequent settlement conferences to address the issues. Comments jointly filed by Pacific Northwest Net Purchasers state that there was inadequate time either to document the harm suffered, or to engage in meaningful settlement discussions with affected sellers. Given these circumstances, they request additional process on this matter.

Spot market sales outside of California were not based on bids into an auction, and instead were made through bilateral contracts.[74] Many commenters note the enormity of attempting to unravel such transactions retroactively. Still others claim that this task must be undertaken in order to put other parties on an equal footing with California. In light of the complexities associated with these retroactive bilateral calculations and the absence of any further development of this issue in the settlement proceeding, and in recognition that the prior settlement proceeding focused primarily on California, we will establish a separate preliminary evidentiary proceeding pertaining to the Northwest. The proceeding is intended to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001.[75] The record should establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. This will help the Commission to determine the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest. We also strongly encourage the parties to try to settle past accounts.

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[74] What is a "spot market" sale for bilateral transactions in the Pacific Northwest may differ from what is a "spot market" sale in the California ISO and PX organized spot markets.

[75] December 25, 2000 is the earliest refund effective date the Commission could establish for Puget's complaint regarding rates in the Pacific Northwest if the Commission determines that it is appropriate to deny Puget Sound's motion to withdraw the complaint, and, further, to grant rehearing of the Commission's previous determination not to set the complaint for hearing.

Accordingly, we direct all parties to the Puget Sound complaint proceeding to participate in the proceeding and to focus on settling past accounts related to spot market sales in the Pacific Northwest. Interested parties to the SDG&E proceeding may participate at their discretion. We direct the Chief Administrative Law Judge or his designee to appoint a judge to convene a conference no later than August 2, 2001, and we require the parties to provide the data described above to the presiding judge no later than 15 days thereafter. We direct the presiding judge to complete discussions within 30 days following the submission of this data. The judge shall make a recommendation and certify the record and findings of fact to the Commission within 7 days after the close of the discussions.[76]

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Section 402(a) of the Department of Energy Organization Act and the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held in Docket Nos. EL00-95-031 and EL00-98-030 concerning refund amounts, as discussed in the body of this order.

(B) Administrative Law Judge Birchman shall convene a conference in this proceeding, to be held as soon as practicable after the date of this order, in a hearing room of the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

(C) The ISO is hereby directed to provide Judge Birchman with data, as discussed in the body of this order. Judge Birchman is hereby directed to certify the record and findings of fact to the Commission no later than 45 days after such data is provided.

(D) The parties to the proceeding in Docket No. EL01-10-000 are hereby directed to participate in discussions before an Administrative Law Judge, to be designated by the Chief Administrative Law Judge, as discussed in the body of this order.

(E) No later than 7 days after the completion of discussions in Docket No. EL01-10-000, the designated judge shall make a recommendation to the Commission.

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[76]The Commission intends to take up the Motion to Withdraw in Docket No. EL01-10-000, Puget Sound Energy Inc. v. All Jurisdictional Sellers of Energy, et al., in an expeditious time frame after the judge's certification of the record.

(F) Requests for rehearing of the November 1 Order regarding the Commission's retroactive refund authority (i.e., refund authority prior to October 2, 2000) are hereby denied.

(G) Requests for rehearing of the March 9 Refund Order regarding the Commission's authority to require refunds from non-public utilities and regarding the application of price mitigation during all hours are hereby granted.

(H) The Oversight Board's March 1 motion is hereby denied.

(I) The request for rehearing of the December 15 Order filed by Southern California Water Company is hereby dismissed.

(J) The request for rehearing of the March 9 Order filed by American Public Power Association is hereby dismissed.

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

(S E A L) Commissioners Breathitt and Massey jointly dissented in part with a separate statement attached.
Commissioner Breathitt dissented in part with a separate statement attached.

David P. Boergers,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,
Complainant,

v.

Docket Nos. EL00-95-004
EL00-95-005
EL00-95-019
EL00-95-031

Sellers of Energy and Ancillary Services 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. EL00-98-004
EL00-98-005
EL00-98-018
EL00-98-030

Puget Sound Energy, Inc.,
Complainant,

v.

Docket Nos. EL01-10-000
EL01-10-001

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.

(Issued July 25, 2001)

MASSEY, Commissioner, dissenting in part and concurring in part:

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I am pleased that the Commission today addresses head on the tough issue of refunds for the victims that took the brunt of the wildly dysfunctional Western power market. The issue comes back to us after a brief attempt by our Chief ALJ to bring the parties together in a voluntary settlement. Judge Wagner did an admirable job under very difficult circumstances and we owe him our gratitude for the valiant effort. But now it is time for the Commission to fulfill its responsibility to the customers of California and other parts of the West.

One of the issues where I disagree with the majority is extending a potential refund obligation to non-public utilities that are otherwise not jurisdictional. Commissioner Breathitt and I are issuing a joint dissent on that issue today.

Today's order also provides very specific guidance on how refunds are to be calculated back to October 2, 2000. In essence, the order applies retrospectively the mitigation measures the Commission set out in our June 19th mitigation order with some adjustments recommended by Judge Wagner in his excellent report on the settlement negotiations. Although I agree with many of the conclusions we reach, I disagree with some aspects of that guidance.

My first area of disagreement is the use of daily spot gas prices as reported in various publications to determine the fuel cost component of the mitigated market clearing prices. It simply is not clear to me that generators purchased gas at those spot prices to replace the gas used to generate electricity for sale into the spot markets. And we do not have to guess at whether they did or not. We are dealing with an historical locked in period for which expenses are known or knowable. During that period, we can use actual fuel costs to determine the just and reasonable price, and we should do so. In supporting the majority's decision to use a different gas index for the refund calculation than that used for the prospective mitigation, the order says that "the gas treatment in the June 19 order was intended to address and influence purchasing decision for prospective sales" and that "there is simply no support for requiring a similar treatment for retroactive application to past sales." I agree with that. We are not trying to influence future behavior in this order, but instead are determining just and reasonable prices for past periods and refunds for customers. We should use the most accurate data we have, and that is actual fuel costs. Therefore, I will dissent from this aspect of the order.

I also object to the inclusion of a 10% creditworthiness adder in determining the mitigated market clearing price that will be used to calculate refunds. I expressed concerns with including this adder as part of the Commission's forward looking price mitigation plan established in the June 19 order. Today, I conclude that this adder is unnecessary in calculating refunds. Prices skyrocketed in June 2000 and remained high for the better part of a year. Indeed, the Commission found that conditions in the market "have caused, and continue to have the potential to cause, unjust and unreasonable rates...under certain conditions."[1] Yet today's order concludes that there is no opportunity for refunds for transactions before October 2, 2000. I support that conclusion but it is clear that sellers charged prices that were not just and reasonable before that date. The fact that there will be no refunds for sales before October 2, 2000 presents strong equity considerations influencing my conclusion that the creditworthiness adder is not necessary in this generous market. Therefore, I will dissent from this aspect of the order.

As a final note on the California portion of this order, I am concerned that the Commission still fails to address squarely the issue of generation withholding during the refund period and before. The market clearing prices for the refund period are determined by a method that uses the dispatch that actually occurred. As some parties suggest here, the actual dispatches reflect the withholding of more efficient units that drove up the market clearing price. The record in this case contains a number of studies that indicate withholding. Two that come to mind are those submitted by the ISO's director of market analysis, Dr. Anjali Sheffrin, and by Drs. Paul Joskow and Ed Kahn. I find these studies instructive. Today's order fails to take the issue of withholding into account in setting a refund formula.

A separate concern is what could the Commission do if we found deliberate withholding in the California spot markets, or anywhere else for that matter. In a section of the order dealing with whether we can go back before the October 2, 2000 date for refund liability, the order says we can do so only if the seller "did not charge the filed rate or violated statutory or regulatory requirements or rules in applicable rate tariffs." My concern is that the Commission would not be able either to find that these conditions were violated or take other actions against sellers that deliberately withheld power from the market because, until April 26, 2001, there were no tariff conditions prohibiting withholding in western markets. This is a major flaw in Commission policy. The Commission must set the rules of the road in our tariffs. As the Commission updates its standards for approving market based rates, we must include generic tariff conditions nationwide that prohibit this kind of bad behavior. I urge my colleagues to consider prompt action to remedy this flaw.

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[1] San Diego Gas & Electric Company, et al., 93 FERC ¶ 61,121 at 61,349-50 (2000), reh'g pending.

I have one final comment on today's order. The order establishes a 15-day proceeding to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for sales in the Pacific Northwest for the period beginning December 25, 2000. This proceeding has its genesis in the complaint of Puget Sound Energy. Buyers in the Northwest paid outrageous prices for power that caused much economic dislocation. To that end, I am pleased that we finally take up the issue of bringing refund relief to that region. The order states correctly that spot market sales in the Pacific Northwest may differ from the definition of a spot market sale in the California organized spot market. I agree. I believe spot sale in the Pacific Northwest could include sales up to a month's duration or even longer. I would be prepared formally to grant rehearing and investigate the Puget complaint today, but it seems that today's order charts an evidentiary path to reach this conclusion ultimately, and I concur with these provisions.

For these reasons, I dissent in part from, and concur in part with, today's order.

William L. Massey
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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EL01-10-001

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.

(Issued July 25, 2001)

BREATHITT and MASSEY, Commissioners, dissenting in part:

We respectfully disagree with the conclusion reached in this order to extend a potential refund obligation to sellers into the California spot markets that are not jurisdictional public utilities. The majority concludes that while "we do not have direct regulatory authority over power sales by non-public utilities, we do have authority to order them to abide by the market rules we establish to make refunds of unjust and unreasonable rates for sales pursuant to those market rules."

Although this rationale certainly has strong appeal, especially as a matter of equity, we are not sufficiently comfortable with it. The refund rules of section 206 of the Federal Power Act are rather specific. If Congress had wanted the Commission to have refund authority over non-public utilities, Congress would have surely so specified. The breathtaking conclusion that this agency has the power to tell non-public utilities to pay money back will come as a shock to most observers.

We understand and appreciate the strong equity rationale behind the majority's decision. Perhaps this interpretation of the Commission's refund authority ought to be the law, but we are not yet persuaded that it is allowed by existing law. Unfortunately, the majority's conclusion ensures that the matter of refunds will probably never be settled and will be litigated for years.

For these reasons, we dissent in part from today's order.

Linda K. Breathitt
Commissioner

William L. Massey
Commissioner

UNITED STATES OF AMERICA
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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.

(Issued July 25, 2001)

BREATHITT, Commissioner, dissenting in part:

I respectfully disagree with the majority's inclusion of a ten percent creditworthiness adder in the methodology to determine refund liability. The rationale stated in this order, that sellers cannot be assured that buyers will pay the full refunds due, is not persuasive in my opinion.

I was concerned about the creditworthiness adder included on a prospective basis through the market clearing price methodology established in our June 19, 2001 order. There I concurred on this issue. Today I will dissent on this issue because I see even less reason for such an adder to be included on a retroactive basis through the refund methodology.

Linda K. Breathitt
Commissioner

Committee on Governmental Affairs
EXHIBIT #A-37

MEMORANDUM TO: Walter C. Ferguson
Chief of Staff

Daniel L. Larcamp, Director
Office of Markets, Tariffs and Rates

Kevin P. Madden
General Counsel

FROM: John M. Delaware
Deputy Executive Director and
Chief Accountant

SUBJECT: Audit of the Component Costs of Generating Electric Power

The Division of Regulatory Audits recently announced an industry-wide audit of the component costs of generating electric power. The objective of the audit is to determine if Companies' books and records appropriately reflect the cost of generating electric power with emphasis on the procurement and pricing of nitrogen oxides (NOx) allowance and fuel consumed in the production of electric power. Based on input from senior Commission staff, we initially selected six generating companies involved with the state of California. Of the six companies reviewed, five companies are power marketers: Calpine Corporation, Duke Energy, Dynegy Power Marketing, Mirant Americas, and Reliant Energy. The remaining company, Portland General Electric, is a traditional utility.

The audits are currently ongoing, however, our initial audit work disclosed various preliminary observations about the cost of generating electricity that may be useful to Commission staff involved in the refund negotiations for overcharges by numerous sellers of energy into the State of California.

First, all of the power marketing companies have common corporate structures: a Parent Company, a subsidiary Service Company, and an Asset Group. The Asset Group is made up of all the physical power plants owned by the Power Marketer, however, each power plant is a separate Limited Liability Company. The Asset Group is only responsible for the physical operation and maintenance of the power plants and does not purchase or sell electricity.

The Service Company performs the following functions:

- procures all the fuel, NOx allowances, and transportation capacity;
- performs all commodity trading of fuel and electricity;
- enters into financial instruments to hedge the price of fuel and transportation; and,
- sells power into the forward and/or spot market.

The Service Company and the Asset Group companies have operating agreements that determine how the cost of fuel and the amount of revenue are allocated from the Service Company to the generating companies.

Second, we determined that the accounting methods used by the five power marketers differ not only from traditional utilities like Portland General Electric, but also vary greatly among themselves.

As an example, the Service Companies generally do not attempt to segregate the inventories of gas burned at their own generating plants from the inventories of gas that is sold to third parties. Instead, they treat all gas purchases as part of their "pool" of gas resources. This pool of resources is managed by commodity traders who enter into purchase, sale, swap and hedge transactions to minimize the company's risk of price fluctuations. The cumulative effect of thousands of intertwined purchases, sales, swaps, and options results in an inability to determine the actual cost of gas burned by the generators.

The inability to reconcile specific prices paid with the specific gas burned has led companies to employ a variety of accounting methods to track fuel costs. Mirant Americas apportions the cost of gas purchased specifically for use by its California generators and allocates these *actual* costs on a pro rata basis, based on fuel usage per generation unit. In addition, Mirant Americas also passes on the net gains or losses resulting from hedging fuel costs. On the opposite extreme, Duke Energy and Reliant Energy price the gas burned by their generators based on an *index* price, which is the average daily spot market price at the hub nearest each generation plant. Calpine Corporation and Dynegy Power Marketing use a combination of actual and index pricing when determining their cost of gas used in generating electricity.

Third, the Service Companies also use different methods to calculate the revenues recorded on the Asset Group company's books. Reliant Energy, Dynegy Power Marketing, and Mirant Americas records revenues at the actual price of their energy sales. Mirant Americas, however, pays its Asset Group fifty percent of profits above a targeted amount. Calpine Corporation uses a combination of accounting methods. Depending on the generating plant, revenues may be recorded at actual or at a spot market index. Duke Energy uses only a spot market index to record revenues.

Finally, in granting market based rate authority, the Commission waived its accounting standards for power marketers. Therefore, staff should not assume that responses to their data requests provide cost data consistent with FERC accounting standards. Since power marketers use various accounting methods, we advise staff that accounting data maintained and submitted by companies may be completely inconsistent with one another and, therefore, are not comparable.

cc: Cynthia Marlette
Marsha Gransee
Ellen Schall
Andrea Wolfman
Michael Bardee
Shelton Cannon
Richard O'Neill
Alice Fernandez
Kevin Kelly
Donald Gelinas
Michael Coleman
Michael McLaughlin
Scott Miller

Committee on Governmental Affairs
EXHIBIT #A-38

For Internal Use Only

Electronic Platforms and Energy Trading
Talking Points addressing Common Misperceptions

Q. Are Enron's financial products increasing risk in the energy industry?

Enron's products decrease risk in the energy industry. As can be seen by this graph [see comparison of electric and gas volatility v. S&P 500], the spot market for electricity and natural gas are extremely volatile. The impact of this volatility on end-user customers can be successfully mitigated through the use of various hedging mechanisms currently available in today's marketplace – many of which were innovated by Enron. Enron designs products that protect end-users, producers and utilities from energy price volatility.

The recent situation in California's electric market highlights the volatile nature of the energy markets, as well as the risk associated with NOT having a hedging strategy in place. Among California's most serious mistakes was the requirement that utilities purchase their electricity from the volatile spot market rather than allowing them to "hedge" by entering into long-term contracts with stable prices. The fact is, had hedging tools been employed, the California utilities could have been freed from vast amounts of risk that have threatened their existence and raised the cost of their product (i.e., electricity) to customers.

Enron has been a leader in developing risk management products designed to stabilize prices for utilities and end-use consumers. These risk management products have become increasingly flexible, and can be tailored to the specific needs and risk attributes of the customer.

Q. Does Enron take on risk?

When Enron enters into a financial derivative transaction with a customer, the risk is transferred from a customer to Enron. We, in turn, manage this risk as part of our overall portfolio, or sometimes lay off the risk in the exchange traded market.

Q. What prevents Enron from being financially ruined by trading losses?

Much has been written about the substantial losses incurred by companies such as Sumitomo and Baring's Bank. These losses were due in large part to inadequate internal controls. Enron has rigorous protections in place to avoid significant losses, such as separation of function policies and a rigorous risk management support function to monitor our portfolio and ensure that risks are within internally established limits and that market risk is carefully controlled.

Next, on a day-to-day basis, Risk Assessment and Control (RAC) unit at Enron – headed by Enron's Chief Risk Officer and staffed by a group of 150 finance professionals -- independently measures and evaluates Enron's multiple risks. RAC operates independently from the units that create or actively manage risk exposures to ensure compliance with Enron's separation of function policies. RAC sets credit limits for trading counterparties, monitors the financial performance of assets and screens internal and external capital expenditures. The core RAC members meet every morning to assess the previous day's events.

At the design and implementation level, the Research Group at Enron – a collection of approximately 60 researchers most of whom are doctorally qualified in mathematics, finance, and other quantitative fields – is reponsible for studying price behavior of energy commodities, developing new models for risk assessment and modifying the existing models of risk quantification (Value at Risk and other methodologies), and testing and implementing the newly developed models. In addition, Enron has an external "reviewer" (a leading scholar in the area of derivative pricing and risk management) of its Value at Risk methodologies.

In addition, consistent with the first recommendation of the Group of Thirty Derivatives Project, Enron's senior management is very well educated on derivatives and other financial instruments. Management doesn't permit traders to "self-supervise." Therefore, it is very difficult to obscure losses by one or more traders.

Traders' activities, including trade verification and pricing of trades, are independently monitored by Information Management to effectively avoid any possibility that they could mislead management about their positions.

Q. What differentiates Enron's activities and exposure from Long Term Capital Management?

The demise of LTCM – which had made directional bets on the narrowing of the price difference between U.S. and emerging market bonds -- came as a result of unrestrained borrowing (a 30-1 leverage position; some claim the ratio was as high as 100-1), an adverse movement in emerging market bonds due to the Russian crisis, and the lack of liquidity in the relevant markets. By contrast, Enron's corporate debt to equity ratio is approximately one to one – quite consevative by market standards. Also, energy commodities are generally far more liquid than emerging bond marekts. LTCM expected to profit by holding extremely large positions in illiquid markets, whereas EnronOnline provides liquidity to energy markets.

In the case of LTCM, many of the big lenders were banks that lacked sufficient information from LTCM. The Federal Reserve intervened to facilitate a bailout LTCM out of fear that the losses from LTCM lending threatened the stability of the U.S. financial system. Enron's financial condition is subject to SEC publilc reporting requirements, including annual audits by independent auditors and even if Enron were to fail, public funds would not be in jeopardy.

Q. Is there is a regulatory gap with respect to the physical and financial energy products offered by Enron?

There is no regulatory gap. The energy products offered on EnronOnline are subject to federal oversight as follows:

The Commodity Futures Trading Commission ("CFTC") has enforcement authority over physical transactions on Enron Online to police for potential manipulation. The Federal Energy Regulatory Commission ("FERC") has regulatory authority over physical natural gas and electricity sales for resale.

The CFTC has anti-fraud and anti-manipulation enforcement jurisdiction over financially settled derivatives (swaps and options). Moreover, pursuant to the Commodity Exchange Act ("CEA"), Enron can only trade derivatives with counterparties that qualify as sophisticated according to such rules. Such transactions are permitted as long as both parties are Eligible Contract Participants ("ECPs")(generally, corporations, partnerships and other entities that meet net worth or asset tests).

EnronOnline is a proprietary, bilateral trading platform on which Enron is a principal to every trade. As such, EnronOnline is not a "trading facility" as defined under the CFMA. As a proprietary platform, EnronOnline uses Internet technology to provide another method of communication between Enron and its customers.

Q. Can the general public access EnronOnline and buy derivatives from Enron?

No. As described above, Enron can only trade derivatives with counterparties that qualify as "sophisticated" according to the CFTC's rules. Such transactions are permitted provided both parties are "eligible contract participants." Generally, corporations, partnerships and other entities that meet net worth or asset tests and individuals with $10 million in assets or $1 million in net worth and enters into the transaction in connection with its business.

Q. EnronOnline "sets" the price.

Enron provides price transparency by posting the prices at which we will buy and prices at which we will sell. Enron posts the bid / ask prices based on our positions, forecasts and cost structure. Our price is just that – our price. If we offer prices that are too low, market participants will buy from us; if we offer prices too high, market participants will sell to us. Further, the customer can utilize the price information to shop for a better deal with one of our many competitors.

Q. EOL / Enron is too big.

Enron has been very successful in trading energy products. Our success is due to a number of factors including an increased demand for risk management products in many markets, including energy markets. This increased demand is due to the rapidly growing realization of corporate and commercial energy users of the need and benefit of managing energy price risk, particularly in the face of increasing price volatility in the energy markets.

Currently, there are over 60 [confirm] energy trading platforms. Several of Enron's competitors have banded together to form trading platforms:

- Intercontinental Exchange, a consortium of 13 leading energy trading firms, including heavy hitters such as Duke Energy, BP Amoco, Shell, Goldman Sachs
- DynegyDirect
- TradeSpark, includes energy companies such as Williams Energy, Coral Energy and Dominion.

Enron competes with major players such as El Paso (a huge player in the financial market), Aquila, Duke, Reliant, AEP, Dynegy, among others.

In addition, three of the largest energy trading platforms in the world (which continue to grow in the face of this new competition) are the global futures exchanges.

- New York Mercantile Exchange (NYMEX)
- International Petroleum Excchange (IPE)
- Singapore Exchange

Q. Is Enron's success linked to increases in energy prices?

Enron's success is linked to efficient markets, not higher prices. Enron buys in the market, and sells in the same market. As the price in the market increases, Enron is subject to price increases as are all buyers in the market. Generally, Enron makes money on the difference between the buy price and the sell price. It also makes money on the difference between the price it can buy or sell energy and the price it can cover its costs (hedge costs). In both cases, it is indifferent to the direction of the price.

Q. Enron claims to provide liquidity to the energy market. What does this mean to consumers?

Enron provides liquidity to the energy market. Market liquidity risk is risk that a position cannot be put on or taken off without significant price disruption, adversely affecting market participants who wish to hedge with a new position or liquidate an existing position.

Liquidity is present when:

- suitable counterparties are available for a trade;
- transactions occur without significantly affecting the market price.
- trading volumes are high, and the bid-ask spreads are low; and
- market exposure can be eliminated quickly and at fair cost.

The benefits of liquidity to market participants include:

- difficulty for one trade to affect market prices, **thus reducing the risk of market manipulation;**
- lower price volatility;
- more players in the market (therefore, more competition and better prices);
- easier for consumers to find a buyer or seller at price they prefer;
- easier for consumers' energy providers to manage risks and costs (which benefits are passed on to consumers); and
- lower transaction costs.

Q. What is the impact of financial derivatives on the physical price of gas?

The correlation between the physical and financial markets has been described as follows:

"...the value or price of natural gas futures and options depends upon the price of physical gas in the spot market. In general, the price of derivatives is highly correlated with the cash-market price of their underlying variables. Thus, when the spot price of gas increases or decreases so too does the future price of gas, and vice versa. It is the correlation between the price of derivatives and the price of their underlying variable that makes risk management possible."[1]

Financial theory prices derivatives based on the price of the underlying physical commodity. In a liquid and efficient market, the derivative impacting the price of the underlying commodity would be akin to the tail wagging the dog.

Q. Can Enron's activities in the financial markets adversely impact the index price of gas in the physical market?

Just the opposite. More activity and more liquidity in the financial markets provides for better price discovery which carries over to the physical markets. Traditionally, it has been the buyers and owners of physical assets that are the greatest threat to distort prices through controlling supply or delivery channels as has been seen with Sumitomo in the copper markets or the Hunt brothers in silver. Financial market participants have no similar ability to control the physical commodity and cannot cause the same concerns.

[1] The Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues", National Regulatory Research Institute, May 2001, page 8.

Enron's Responses to Kim Bruno (FERC) questions dated 6/14/01

Question 1: In providing an answer to our questions regarding risk assessment or management, would you please provide an explanation to the following? We understand that EOL requires that a counter party, before accessing EOL to do business with Enron North America, must undergo a credit worthiness evaluation. When a counter party executes or clicks on a price, EOL does an instant credit check before confirming the transaction.

However, Enron may not only buy from a counter party, it may sell. What sort of creditworthiness standards must Enron provide to a counter party utilizing EOL to purchase from Enron?

Are there industry standard creditworthiness agreements regarding counter party credit risk that Enron uses? If yes, may we have copies? If Enron utilizes its own agreements, please provide us with a copy.

All counterparties are assessed by our credit department prior to any transaction being entered into by Enron whether the transaction is being conducted over the phone or through EnronOnline. Enron, as the principal to all purchases and sales on EnronOnline and when completing transactions on the telephone or in writing, requires counterparties to be creditworthy. In addition, Enron's risk management policy is approved by the Enron Board of Directors. Enron's value at risk is provided in Enron's 10-K. Enron maintains a separate risk management group that has oversight over all transactions done by all Enron trading units and that ensures compliance with the risk management policies. This group has a separate reporting line directly to the office of the Chairman of Enron Corp. and has the authority to instruct the suspension of transactions in order to ensure that trading limits are not exceeded. In addition, every counterparty of Enron has to clear a credit check before they can transact through EnronOnline. The Credit Risk Management group approves a counterparty for a specific credit limit and tenor limit which are embedded within the EnronOnline database. Every transaction is passed through an electronic credit check to assure that the credit limits and tenor limits are not violated prior to Enron accepting the counterparty's bid or offer via EnronOnline, -- such credit checks are done automatically and there is no human intervention. As with all Enron transactions, the credit limit checks utilize a potential exposure calculation to take into account future price volatility. The Credit Risk Management (CRM) group monitors transaction flow on all Enron transactions including EnronOnline continually. EnronOnline does provide CRM with electronic alerts when customers approach credit limits or breach credit limits. No further transactions are executed unless CRM is sufficiently satisfied that the credit position has been mitigated such that credit limit is still available.

EnronOnline uses the same credit policy as other transactions Enron enters into, whether we are buying or selling. The transactions entered into on EnronOnline are all governed by either a Master Agreement or the General Terms and Conditions (which are a shorter form of contract and differ for each commodity, these are all available on the web-site). A Master Agreement is negotiated with the Counterparty offline and includes negotiated bilateral credit terms and these terms govern any transactions entered into on EnronOnline. The General Terms and Conditions which will apply to EnronOnline transactions if there is no Master Agreement in place between Enron and the counterparty include industry standard credit requirements which the counterparty chooses to accept or not online. Should the counterparty not want to accept language in the contract (for credit or other reasons), the Helpdesk for EnronOnline will facilitate contact between the Enron Credit group or Enron Legal group with the counterparty allowing the Counterparty to negotiate terms which may be more appropriate to them.

Question 2: I understood Dave Forster to state that EOL does not collect data regarding where a customer's mouse is moving on the system. However, does EOL require customers to have cookies enabled? If yes, does EOL collect, use or manage data regarding cookies?

It is correct that Enron does not collect data regarding where a customer's mouse is moving on the system. It is also correct to note that we have no capability of knowing where the customer's mouse is.

EnronOnline does not require customers to have cookies enabled.

Question 3: Also, why doesn't EOL publish a "ticker" of completed trades showing prices and quantities? Does EOL have any plans to start publishing such data? If yes, when?

There are now several options for viewing historical pricing/transaction data from EnronOnline. Reuters recently began showing quotes from EnronOnline (http://about.reuters.com/enrononlinequotes/), which also provides customers with the ability to reference historical prices from the date at which they acquire access. In addition, EnronOnline provides a number of online charts for products, which graphically depict historical transaction prices. Customers can also run reports to see their own transactions and download the results into an Excel spreadsheet on EnronOnline The system also allows for administrative users, thereby allowing the back offices of counterparties to monitor the trading activity and deal with it appropriately in line with their own systems.

Enron does not publish transactions completed via EnronOnline; however Enron will provide information on such transactions in order to ensure market activity is being correctly reflected in the approriate market indices. For example, Enron does provide EnronOnline transaction data to the Natural Gas Exchange in Calgary in order to ensure that indices produced by Canadian Enerdata accuately reflect the activity in the market place (this will commence on July 1, 2001). At the end of each day, EnronOnline makes available to all customers through EnronOnline the weighted average price of that day's transactions. The data associated with US Natural Gas is sent in this format to Gas Daily for inclusion in their automated exchange index.

Question 4: In addition, how does the data collection from EOL/Enron Networks flow to the risk management groups? How is the information used?

EnronOnline transactions are sent to different risk management groups depending on the type of commodity transacted. For example, the group that handles U.S. gas settlements is not the same group as the one handling Australian Power. The transactions are transmitted to the appropriate back office utilizing a "bridge": a process that is capable of communicating transaction information into the variety of systems that Enron operates. The potential for manual input error is thereby removed providing Enron and the customer with more efficient recording of the transaction. The back office systems at Enron use transaction information as an input into various functions, such as invoicing, preparation of financial statements, risk management and credit. These back office systems are used to track transactions from all sources, including EnronOnline, the telephone, other trading systems, etc. Information is maintained on these systems according to accounting and regulatory rules, regardless of the source of the transaction.

The Enron commercial employee, who is offering to buy or to sell through EnronOnline, does so through a price management software application, this notifies him immediately that a transaction is completed. The counterparty, the Enron commercial employee and the risk management groups are all notified by the system at the same time.

The data from an EnronOnline transaction is used in exactly the same way as information is used from any transaction completed by Enron. When a transaction is completed, EnronOnline serves purely as a deal capture system that captures the data necessary to feed to our risk management system. Enron Online does not feed settlement systems or credit systems. It does, however, automate our deal capture system, which improves the data feeds to our settlement and credit systems.

Question 5: Also, we assume that data regarding each trade is maintained by EOL. If yes, in what form and for how long?

EnronOnline transactions are captured in the EnronOnline database. The transactions are 'bridged' (duplicated) onto the various systems (databases) managing the underlying commodity (the risk system associated with the commodity). We currently intend to store the data for a period of six years post a transaction completing (for example, deliveries finishing) and this is policy across all databases.

Additional requests during on-site visit:

In general, EnronOnline is an electronic trading platform that offers free, real-time pricing information for approximately 1,800 products for 13 commodities, including electricity and natural gas. EnronOnline utilizes e-commerce and Internet technology to conduct trading business that previously took place on the telephone and by fax. EnronOnline is a proprietary, or "one-to-many" trading platform. On a "one-to-many" platform, one entity, such as Enron, is the principal to every trade (unlike a "broker" type platform).

EnronOnline allows buyers and sellers to act on prices that can change by the second. Buyers or sellers can also see real-time price spreads of both the sell price and the buy price. For example, on the telephone, a buyer previously would call to ask about gas prices for each of the next six months, but by the time the trader finished reciting the prices, some prices could have changed. EnronOnline allows counterparties to see the 'bid and offer prices" all the time to make more informed decisions.

The energy products offered on EnronOnline are subject to federal oversight as follows: The Commodity Futures Trading Commission ("CFTC") has enforcement authority over physical transactions on EnronOnline to police for potential manipulation. The Federal Energy Regulatory Commission has regulatory authority over physical natural gas and electricity sales for resale.

The CFTC has anti-fraud and anti-manipulation enforcement jurisdiction over financially settled derivatives (swaps and options). Moreover, pursuant to the Commodity Exchange Act ("CEA"), Enron can only trade derivatives with counterparties that qualify as sophisticated according to such rules. Such transactions are permitted as long as both parties are Eligible Contract Participants ("ECPs")(generally, corporations, partnerships and other entities that meet net worth or asset tests).

EnronOnline is a proprietary, bilateral trading platform on which Enron is a principal to every trade. As such, EnronOnline is not a "trading facility" as defined under the CFMA. As a proprietary platform, EnronOnline uses Internet technology to provide another method of communication between Enron and its customers.

Committee on Governmental Affairs
EXHIBIT #A-39

ENRON WASHINGTON
MEMORANDUM

TO: Janel Guerrero
FROM: Linda Robertson
DATE: July 27, 2001
RE: **Update of Federal Government Affairs Energy Crisis Campaign**

Accomplishments to Date

- Continuously brought Enron's perspective on market and policy developments to the attention of senior Executive Branch and Legislative Branch officials, including the Vice President, DOE, FERC, Congressional leadership and key energy committees.

- Special focus on California and other West Coast Members, particularly wavering Republicans and moderate Democrats.

- These efforts paid off when the House took up "emergency" California-oriented energy legislation (House subcommittee adopted the Enron negawatts "demand buy down" proposal and defeated statutory price controls). Similarly, the House Energy and Commerce Committee rejected price control and refund amendments during action on the energy package, with support for Enron's positions from all Republicans and the swing Democrats we targeted).

Matters Going Forward For Balance of Year

- Continuing threat of adverse price control, refund and other amendments as Congress considers energy legislation, such as House floor consideration of the energy package next week; Senate Energy and full Senate action after Labor Day; and House committee consideration of a separate electricity bill after Labor Day. Created "myths and facts" document to change the nature of the debate in Washington about the origins of and solutions to the California crisis. Items from the document have been used by members during price cap and other debates.

- Provided a steady stream of timely information that has allowed members to refute charges against Enron specifically and free markets generally.

- Developed and implemented strategy to defend regulatory structuring surrounding EOL and EOL products.

Enron: Enron Corp. -- Press Release

Committee on Governmental Affairs
EXHIBIT #A-40

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Press Release

ENRON SECURES COMMITMENTS FOR ADDITIONAL $1 BILLION IN FINANCING

FOR IMMEDIATE RELEASE: Thursday, November 1, 2001

HOUSTON — Enron Corp. (NYSE:ENE) announced today that JPMorgan (the investment banking arm of JP Morgan Chase & Co.) and Salomon Smith Barney Inc. (the investment banking arm of Citigroup Inc.) as co-arrangers have executed commitment letters to provide $1 billion of secured credit lines supported by Enron's Northern Natural Gas Company and Transwestern Pipeline Company assets. The proceeds will be used to supplement short□term liquidity and to refinance maturing obligations. These commitments are subject to customary terms and conditions, including final due diligence.

"With more than $1 billion in cash currently on our balance sheet, this additional credit capacity will further solidify Enron's standing as the leading market maker in wholesale energy markets," said Kenneth L. Lay, Enron chairman and CEO. "We very much appreciate the support of two of our longstanding banking partners, JPMorgan and Citigroup."

"This is yet another step in our efforts to enhance market and investor confidence," said Jeffrey McMahon, Enron chief financial officer. "We are moving aggressively to strengthen our balance sheet and maintain our investment grade credit rating."

Copies of the commitment letters will be filed with the Securities and Exchange Commission in a Form 8-K filing shortly.

Enron is one of the world's leading energy, commodities, and services companies. The company markets electricity and natural gas, delivers energy and other physical commodities, and provides financial and risk management services to customers around the world. Enron's Internet address is www.enron.com. The stock is traded under the ticker symbol "ENE."

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

In Re Investigation of Certain Financial Data Docket No. IN02-6-000

ORDER TO RESPOND

(Issued August 1, 2002)

Issued to:
Northern Natural Gas Company
Transwestern Pipeline Company

1. Pursuant to sections 5, 7, and 16 of the Natural Gas Act (NGA), 15 U.S.C. §§ 717d, 717f, and 717o, this Order to Respond (Order) directs Transwestern Pipeline Company (Transwestern) and Northern Natural Gas Company (Northern), which are or were jurisdictional interstate pipeline subsidiaries of the Enron Corporation (Enron), [1] to state why they have not violated the Commission's Uniform System of Accounts for natural gas companies, [2] and why the costs and indebtedness associated with loans totaling approximately $1 billion made by the pipelines with Citicorp North America, Inc. (Citicorp) and JP Morgan Chase Bank (JP Morgan) within two weeks of Enron filing for Chapter 11 reorganization under the Federal Bankruptcy Code were not imprudently incurred and therefore unrecoverable by the pipelines in any future rate proceedings before this Commission.

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[1]Northern was purchased by Dynegy, Inc. in February, 2002. On July 29, 2002, MidAmerican Energy Holdings Company announced that it intended to purchase Northern from Dynegy.

[2]Part 201 Uniform System of Accounts Prescribed for Natural Gas Companies Subject to Provisions of the Natural Gas Act, 18 C.F.R. Part 201 (2002).

Procedural Background

2. In November 2001, the Chief Accountant, concerned over the financial control exerted by parent companies over the assets of their jurisdictional subsidiary companies, began a review of transactions between parent companies and their jurisdictional subsidiaries. Specifically, the balances in the cash account and accounts related to associated companies, reported in the FERC Forms 1, 2, and 6, were reviewed for the years 1997 through 2001. This review revealed that certain companies had significant balances in gas and electric Account 146 - Accounts Receivable from Associated Companies, and oil Account 13 - Receivables from Affiliated Companies, and that the balances in these accounts had significantly increased over the period under review. These accounts are used to record receivables for items such as revenue for services rendered, material furnished, rent, interest and dividends, advances and notes. Company personnel interviewed stated that the account balances were increasing due to participation in cash management or money pool programs with their parent companies.

3. An audit was initiated for selected natural gas and oil pipelines and public utilities in January 2002, to determine compliance with the Commission's accounting and reporting requirements for the years 2000 through 2001.

4. On March 1, 2002, the Commission instituted a non-public investigation regarding financial data related to transactions, activities and accounting practices that may have impaired the financial condition of entities subject to the Commission's jurisdiction for the benefit of corporate parents or other affiliates or associated entities of jurisdictional companies.

Loan Agreements of Transwestern and Northern

5. Transwestern and Northern did not have written cash management agreements with Enron.

6. In November 2001, Transwestern and Northern, at the request of their parent, Enron, entered into revolving credit agreements for $550 million and $450 million, respectively, with Citicorp and JP Morgan. Both pipelines pledged their pipeline assets as collateral under the respective loan agreements. Subsequent to these transactions, Enron entered into agreements with Transwestern and Northern for the same funds.

7. Specifically, on November 13, 2001, Enron Corporation entered into two subordinated promissory notes with Transwestern for $137.5 million and $412.5 million (totaling $550 million). The notes state that they are subordinated to prior payment of all

senior indebtedness upon dissolution, liquidation, or reorganization for the benefit of creditors of Enron. Interviews with Transwestern's Manager of Financial Accounting and Reporting revealed that the $137.5 million was used to pay off a portion of a $250 million unsecured loan outstanding by Enron North America, another Enron subsidiary, to Citibank (a member of Citicorp). The remainder of the funds ($412.5 million less $10 million held by Transwestern for operating capital) was swept to Enron under a cash management program in exchange for the second subordinated note. As of June 14, 2002, Enron has made no payments on the subordinated notes. Transwestern has written these notes off as unrecoverable.

8. Notes to Transwestern's FERC Form 2 for 2001 provide additional information. On December 31, 2001, Transwestern was in default of the debt covenants requiring the company to maintain a net worth of no less than $750 million. Due to Enron's bankruptcy, Transwestern reserved the balance in Account 146 ($785 million) which reduced the company's net worth. On April 30, 2002, the Citicorp debt agreement was amended to reduce the tangible net worth test to $400 million and the default was waived.

9. On November 19, 2001, Enron entered into an assignment and assumption agreement with Northern for $112.5 million. This amount was used to pay off the remainder of the Enron North America unsecured loan discussed above. Northern also entered into an agreement with MCTJ Holding Company (MCTJ), a limited liability company, set up between Enron and Northern. This agreement consisted of a note for $307.5 million, the remainder of the $450 million loan less $30 million held by Northern in a bank account for operating capital. Northern personnel stated that MCTJ then distributed the $307.5 million to another Enron subsidiary, CGNN Holdings Company, Inc., MCTJ's parent, which in turn loaned the funds to Enron.

10. Additionally, Northern received $1.5 billion from Dynegy, Inc., in return for Series A Preferred 6% stock issued in November. At the same time, Northern loaned the proceeds to MCTJ, which in turn distributed the funds to Enron. Northern has recorded the $1.5 billion in Account 145 - Notes Receivable from Associated Companies.

11. During staff's audit in early March 2002, the Director of Financial Accounting and Reporting for Transwestern and Northern indicated that Enron had the pipelines take out the November 2001 loans to try to hold off a declaration of bankruptcy. He also indicated that neither company expected to receive any repayment of these loans due to Enron's bankruptcy. The pipelines are still liable for the entire $550 million and $450 million.

Discussion

12. The Uniform System of Accounts requires that jurisdictional entities keep their " books of account, and all other books, records, and memoranda which support the entries in such books of account so as to be able to furnish readily full information as to any item included in any account. Each entry shall be supported by such detailed information as will permit ready identification, analysis, and verification of all facts relevant thereto." [3]

13. It appears that due to the failure to maintain written cash management agreements with Enron, neither Transwestern nor Northern were able to support entries in Account 146 of the Uniform System of Accounts.

14. Therefore, the Commission is directing Transwestern and Northern each to provide written responses stating why the Commission should not find that each of them has violated the General Instructions-Records under Part 201 of the Uniform System of Accounts by failing to maintain written cash management agreements with Enron.

15. Under sections 4, 5 and 7 of the NGA: (1) the rates, charges and services of natural gas companies must be just and reasonable and not unduly discriminatory; (2) the Commission may, after a hearing on its own motion, find that the rates, charges, or services of a natural gas company are unjust, unreasonable or unduly discriminatory and accordingly modify such rates, charges, or services by order; and (3) the jurisdictional services provided by natural gas companies may be authorized on the basis of a finding that such services are in the public interest.

16. It appears that the loans made by Transwestern and Northern described above were imprudent. It further appears that Transwestern and Northern will experience an increased credit risk as a result of the loans and will have a significantly higher cost of capital.

17. Therefore, the Commission is directing Transwestern and Northern each to provide written responses stating why the Commission should not find that the November 2001 loans described above were imprudently incurred, and why the costs arising from such

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[3] See General Instructions-Records under Part 201 of the Commission's Uniform System of Accounts for Natural Gas Companies Subject to the Provisions of the Natural Gas Act.

loans and arrangements should be passed on to ratepayers after the settlement rates now in effect expire. [4]

The Commission orders:

(A) Transwestern and Northern are each hereby ordered, within thirty days of the date of this order, to provide written responses stating why the Commission should not find that each of them has violated the General Instructions-Records under Part 201 of the Uniform System of Accounts by failing to maintain written cash management agreements with Enron.

(B) Transwestern and Northern are each hereby ordered, within thirty days of the date of this order, to provide written responses stating why the Commission should not find that the November 2001 loans as described above were imprudently incurred, and why the costs arising from such loans and arrangements should be passed on to ratepayers after the settlement rates now in effect expire.

By the Commission

(S E A L)

Magalie R. Salas,
Secretary.

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[4]Under the settlement reached in Northern's last general rate case in Docket , No. RP98-203-000, Northern may not file a general rate increase before November 1, 2003, but must file a general rate case not later than May 1, 2004. Under the settlement reached in Transwestern's last general rate case in Docket Nos. RP95-271-000, et al., Transwestern's negotiated settlement rates expire in 2006.

100 FERC ¶ 61,179

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

In Re Investigation of Certain Financial Transactions   Docket No. IN02-6-000

ORDER APPROVING STIPULATION AND CONSENT AGREEMENT

(Issued August 8, 2002)

1. The Commission approves the attached Stipulation and Consent Agreement (Agreement) between the Commission's Chief Accountant, the Market Oversight and Enforcement section, Office of General Counsel and Northern Natural Gas Company (Northern). The Agreement resolves only those issues of fact and law as discussed in the Commission's August 1, 2002 Order to Respond issued in the above referenced proceeding concerning possible violations of the Commission's regulations under Part 201 of the Uniform System of Accounts governing interstate pipelines, 18 C.F.R. part 201 (2002).

2. The Order to Respond directed Northern and Transwestern Pipeline Company to provide, within thirty days, written responses stating why the Commission should not find that each company: (1) violated the General Instructions-Records under Part 201 of the Uniform System of Accounts by failing to maintain written cash management arrangements with their parent, Enron Corporation (Enron); (2) entered into imprudent loans, the proceeds of which were transferred to Enron shortly before Enron filed for bankruptcy; and (3) should be prohibited from passing costs arising from such loans and arrangements on to ratepayers after settlement rates now in effect expire.

3. The Agreement provides, among other things, that Northern and its parent company [1] will comply with the provisions of the Final Rule regarding written cash management practices resulting from the Commission's Notice of Proposed Rulemaking, Regulation of Cash Management Practices, in Docket No. RM02-14-000 issued on

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[1]Northern is currently owned by Dynegy, Inc. On July 29, 2002, MidAmerican Energy Holdings Company agreed to purchase Northern from Dynegy subject to certain closing conditions.

August 1, 2002.[2] Northern will not include the costs associated with the $450 million loan entered into on November 19, 2001, with Citicorp North American, Inc. and JP Morgan Chase Bank as co-administrative agents in any future Commission rate proceedings before the Commission. Specifically, Northern will not include the loan itself, the interest cost of the $450 million loan, or the cost of acquiring such loan, in any future Commission rate proceedings.

4. The Commission finds that the Agreement provides an equitable resolution of the specific issues raised in the August 1, 2002 Order to Respond with respect to Northern and is in the public interest. Approval of this Agreement does not constitute settlement or waiver of any further action or remedies the Commission may find appropriate concerning matters that are not addressed in the August 1, 2002 Order to Respond. Further, nothing in this approval constitutes immunity from any civil or criminal action that any other federal agency or department may take.

The Commission orders:

(A) The attached Stipulation and Consent Agreement is approved in its entirety without modification.

(B) The Commission's approval of the attached Stipulation and Consent Agreement does not constitute approval of, or precedent regarding, any principle or issue in this matter.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Deputy Secretary.

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[2] 100 FERC ¶ 61,142 (2002).

UNITED STATES OF AMERICA

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In Re Investigation of Certain Financial Data) Docket No. IN02-6-000

STIPULATION AND CONSENT AGREEMENT

I. Introduction.

On August 1, 2002, the Commission issued an Order to Respond to Northern Natural Gas Company (Northern) and Transwestern Pipeline Company (Transwestern) that directed Northern and Transwestern to state: (1) why they have not violated the Commission's Uniform System of Accounts for natural gas companies with respect to written cash management agreements with their parent; and (2) why the costs and indebtedness associated with certain loans were not imprudently incurred and therefore unrecoverable by Northern and Transwestern in any future Commission rate proceedings.

II. Agreement.

Northern neither admits nor denies any violation of the Commission's Uniform System of Accounts and Northern neither admits nor denies that any of its loans were entered into imprudently. However, Northern, the Chief Accountant, and the Market Oversight and Enforcement Section, Office of General Counsel agree as follows:

A. Northern and its parent 1/ commit that they will comply with the Final Rule regarding written cash management practices resulting from the Commission's Notice of Proposed Rulemaking, Regulation of Cash Management Practices, in Docket No. RM02-14-000 issued August 1, 2002.

1/ Northern is currently owned by Dynegy, Inc. On July 29, 2002, MidAmerican Energy Holdings Company agreed to purchase Northern from Dynegy subject to certain closing conditions.

B. Northern will not include the costs associated with the $450 million loan entered into on November 19, 2001 with CitiCorp North American, Inc., and JP Morgan Chase Bank as collateral trustee, and Citicorp North American, Inc. and JP Morgan Chase Bank as co-administrative agents, in any future rate proceedings before the Commission. Specifically, Northern will not include the loan itself, the interest cost of the $450 million loan, or the cost of acquiring such loan, in any future Commission rate proceedings.

C. Notwithstanding Paragraph B, the Commission acknowledges that Northern will, from time to time, amend, extend and terminate debt or acquire new debt as the economic and financial market environment in which Northern competes for capital dictates. Specifically, it should be noted that the $450 million short-term loan in question will expire or be paid in full on or before November 19, 2002 and will, therefore, not be included in the capital structure of Northern after November 2002. However, the Commission reserves the right to determine, in any future NGA Section 4 rate proceeding, whether the acquisition cost associated with any future refinancing of the $450 million loan was just and reasonable.

D. This Agreement settles any and all civil and administrative disputes, and is in lieu of any other remedy that the Commission might assess, determine, initiate or pursue, including remedies pursuant to Section 5, 7 and 16 of the Natural Gas Act, concerning only those matters specifically described or referred to in the Commission's August 1, 2002 Order to Respond. The Commission reserves the right to pursue any other matters that are not the subject of the August 1, 2002 Order to Respond.

III. Terms.

A. By this Agreement, the Chief Accountant, Market Oversight and Enforcement and Northern intend to settle only the matters referred to in this Agreement and that are within the Commission's jurisdiction and statutory authority to settle.

B. The Chief Accountant, Market Oversight and Enforcement and Northern acknowledge and agree that this Agreement is a settlement only of those matters specifically set forth in the Commission's August 1, 2002 Order to Respond that are being investigated by the Chief Accountant and Market Oversight and Enforcement. Nothing herein is intended to be an admission on the part of Northern of any violation or wrongdoing.

C. The Chief Accountant, Market Oversight and Enforcement and Northern state that they enter into this Agreement voluntarily and that, other than the agreements provided herein, no tender, offer, or promise of any kind whatsoever has been made by any party to this Agreement, or any member, employee, officer, director, agent, partner or representative of any such party, to induce any other party to enter into this Agreement.

D. Except as expressly stipulated and acknowledged and agreed herein, neither the Chief Accountant, nor Market Oversight and Enforcement nor Northern makes or has made any admissions or acknowledgments or agreements in connection herewith.

E. Unless the Commission issues an order approving this Agreement in its entirety without modification, this Agreement shall be null and void and have no effect whatsoever and the Chief Accountant, Market Oversight and Enforcement and Northern will not be bound by any of its provisions or terms, unless they agree otherwise in writing.

F. With the exceptions of any additional administrative or civil remedies that may be imposed for failure to comply with the terms of Part II of this Agreement, any and all administrative or civil remedies that the Commission may have against Northern, its successors or assigns, either before the Commission or in the courts, arising from the matters set forth in Part II of this Agreement, shall be forever barred upon compliance with the provisions of Part II of this Agreement.

G. The undersigned representative of Northern affirms that he/she has read the representations set forth in the Agreement, and that all statements and matters set forth herein are true and correct to the best of his/her knowledge, information and belief, and that he/she understands that the Chief Accountant and Market Oversight and Enforcement enter into this Agreement in express reliance on those representations.

H. The terms and conditions of this Agreement are binding on Northern and its successors and assigns.

I. By its order approving this Agreement, the Commission shall terminate with respect to Northern matters referred to it in the August 1, 2002 Order to Respond. Northern waives any rights to seek further administrative review or to seek judicial review of any Commission order approving this Agreement without modification.

J. Each of the undersigned warrants that he or she is an authorized representative of the party designated, is authorized to bind such party, has notified the party of the terms of this Agreement and accepts it on the party's behalf.

Agreed to and accepted:

John Delaware

John Delaware, Deputy Executive Director
and Chief Accountant

8/8/02
Date

Virginia Strasser

Virginia Strasser, Associate Counsel,
Market Oversight and Enforcement,
Office of General Counsel

8/8/02
Date

Mary Kay Miller

Northern Natural Gas Company

8/8/02
Date

ORIGINAL

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

In re Investigation of Certain Financial Data) Docket No. IN02-6-000

RESPONSE OF TRANSWESTERN PIPELINE COMPANY

In accordance with the Commission's August 1, 2002 Order to Respond in the above-captioned proceeding, Transwestern Pipeline Company ("Transwestern") provides this response demonstrating why it did not violate the Commission's Uniform System of Accounts under Part 201 and why the costs and indebtedness associated with a loan totaling $550 million made by Transwestern with Citicorp North America, Inc. and JP Morgan Chase Bank (hereinafter "Citicorp," "JP Morgan" or "Banks") were prudently incurred. As demonstrated herein, Transwestern's treatment of the loan transactions with the Banks and Enron Corporation ("Enron") was fully consistent with the Commission's accounting regulations and its decision to enter into the loan transactions clearly was prudent in view of the facts that were known by Transwestern during the operative time period: mid-October through mid-November 2001.

In support hereof, Transwestern shows as follows:

I. BACKGROUND.

A. Origin and Subject Matter of FERC's Investigation.

The Commission's August 1, 2002 Order arises from an industry-wide investigation into the balances in the cash account and accounts related to associated companies, reported in the FERC Forms 1, 2, and 6, for the years 1997 through 2001. This investigation was commenced in November of 2001. The Commission subsequently narrowed its investigation and initiated an audit for selected natural gas companies in January 2002 to determine whether those specific companies were in compliance with the accounting regulations under Part 201 and the reporting requirements for the years 2000 through 2001. On March 1, 2002, the Commission instituted a non-public investigation regarding financial data related to transactions for the benefit of corporate parents or other affiliates or associated entities of jurisdictional companies.

The investigation of Transwestern and its pipeline affiliate Northern Natural Gas Company ("Northern Natural") focused on their relationship with Enron, which at relevant times was the parent company of both pipelines. In particular, the Commission investigated two November 2001 revolving credit agreements that Transwestern and Northern Natural entered into, at the request of Enron, for $550 million and $450 million, respectively, with Citicorp and JP Morgan (the "Credit Facility").[1] As described below, Enron contemporaneously entered into agreements to borrow the majority of those loan proceeds from Transwestern and Northern Natural.

On November 13, 2001, Enron executed two subordinated promissory notes in favor of Transwestern for $137.5 million and $412.5 million. The promissory notes provide that they are subordinated to prior payment of all senior indebtedness upon dissolution, liquidation, or reorganization for the benefit of creditors of Enron. Enron borrowed the full amount of the $550 million face value of those notes from Transwestern, less $10 million retained by Transwestern

1 The Commission issued an order on August 8, 2002 approving a Stipulation and Consent Agreement between FERC's Chief Accountant, the Market Oversight and Enforcement section, Office of General Counsel and Northern Natural. In re Investigation of Certain Financial Transactions, 100 FERC ¶ 61,179 (2002). The Agreement resolved the issues of fact and law concerning possible violations of FERC's accounting regulations under Part 201. The Agreement provides, among other things, that Northern Natural and its parent company will comply with the provisions of the eventual Final Rule regarding written cash management practices in Docket No. RM02-14-000. Under the Agreement, Northern Natural consents not to include the costs associated with the $450 million loan in any future rate case.

as supplemental working capital. As a result of the Enron bankruptcy, Transwestern has established a reserve against these loans to Enron.[2]

According to the Commission's Order to Respond, Transwestern purportedly failed to maintain a written cash management agreement with Enron and is unable to support entries in Account 146 of the Uniform System of Accounts. The Commission directed Transwestern to provide a written response stating why the Commission should not find that Transwestern has violated the General Instructions-Records under Part 201 of the Uniform System of Accounts. The Commission also required Transwestern to provide a written response stating why the Commission should not find that the November 2001 loans were imprudently incurred, and why the costs arising from such loans and arrangements should be passed on to ratepayers in a future rate case.

B. Material Facts not Considered by FERC in Issuing the Order to Respond.

The Commission's August 1, 2002 Order is specifically predicated on several incorrect factual assumptions and on a general lack of information as to the overall factual context surrounding the questioned transactions. The chronology of events surrounding the loan agreement and the events leading up to Enron's bankruptcy are essential to a determination of this proceeding. The Commission cannot make a reasoned decision in the absence of this information. The following chronology demonstrates conclusively that, among other things, during the time the loan agreement was considered and entered into, Enron had an investment grade credit rating, the Dynegy-Enron merger was executed, was pending and had not yet been terminated, and Transwestern was in a position to provide a loan to meet its

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2 See Transwestern Pipeline Co. FERC Form No. 2 at 110 (Dec. 31, 2001) ("Form 2").

parent's/stockholder's then pressing need for financial support. Moreover, Transwestern acted reasonably and prudently in its actions leading up to and including the loan transaction.

Chronology of Events Surrounding the Loan Agreement

In October of 2001, Enron was in the midst of financial problems. However, Enron was taking actions designed to remedy those problems. As explained below, Transwestern was requested by Enron, Transwestern's sole shareholder, to evaluate its capacity to incur debt in order to provide financial assistance to Enron. Enron was taking other measures as well. Enron announced its agreement for the sale of Portland General Electric Company ("Portland General") to Northwest Natural Gas Company ("Northwest Natural") on October 8, 2001. The total purchase price of $1.8 billion was to include $1.55 billion in cash, $200 million in Northwest Natural preferred stock, and $50 million in Northwest Natural common stock. In addition to the purchase price, Northwest Natural was to assume approximately $1.1 billion in Portland General debt and preferred stock. The deal also provided that Northwest Natural would assume an approximately $75 million payment obligation from Enron to Portland General. After the announcement of the transaction, on October 9, 2001, Enron declared a regular quarterly dividend of $0.125 per share, payable on December 20, 2001.[3]

On October 16, 2001, Enron reported its first quarterly loss in more than four years after taking charges of $1 billion on poorly performing businesses.[4] Enron also disclosed a $1.2 billion charge against shareholder's equity relating to dealings with partnerships run by its CFO. Enron issued a press release on October 16, 2001 stating that recurring earnings per diluted share

3 See Enron Press Release Date Oct. 9, 2001 (attached hereto as Appendix A).

4 See Enron Press Release Dated Oct. 16, 2001 (attached hereto as Appendix B).

of $0.43 for the third quarter, compared to $0.34 in the third quarter of 2000, with the total recurring net income increased to $393 million, versus $292 million the year before. Enron disclosed on October 22, 2001 that the SEC had asked Enron to provide information on transactions between Enron and certain partnerships.[5]

During this mid-October interval, Enron approached the management of its pipeline subsidiaries to inquire whether these entities possessed adequate debt carrying capacity to facilitate material financial relief for Enron. At that time, Transwestern's senior management believed it to be a sound business objective for the company to respond affirmatively to its shareholder's entreaties *provided that* it could do so in a reasonable and prudent manner. Thus, in response to Enron's inquiry, Transwestern evaluated whether it had adequate debt capacity and therefore whether it was economically feasible from a business standpoint, in the context of both its regulatory environment and obligation to customers, to enter into a loan transaction for the benefit of Enron. Transwestern's management exercised its judgment and considered all relevant matters, including the fact that it had substantial capacity for leverage due to the circumstance that its capital structure was virtually 100% equity. Indeed, shortly before the questioned loan closed, Transwestern paid off the one remaining loan it had outstanding and had a 100% equity capital structure when the loan closed.[6] In addition, teams from JP Morgan and Citicorp conducted a detailed analysis on a historical and projected basis concerning Transwestern's ability to incur some reasonable level of debt without jeopardizing its credit risk or unduly burdening its capital structure. The loan negotiations between Transwestern and JP Morgan and

5 See Enron Press Release Date Oct. 22, 2001 (attached hereto as Appendix C).

6 The only debt Transwestern had outstanding at the end of 2001 was the $550 million loan. See Form 2 at 112-113.

Citicorp were conducted at arms length. Transwestern and the Banks ultimately determined that the loan was fully supported by Transwestern's capitalization and commercial outlook.

Enron issued a press release on October 25, 2001, stating that it continued to have high transaction volume, which showed the strength of Enron's core businesses.[7] On this same day, Enron drew on its committed lines of credit to provide cash liquidity in excess of $1 billion in order to dispel uncertainty in the financial community.[8] This $1 billion was separate and distinct from the questioned loan transactions, which had not yet been publicly announced by October 25, 2001.

On November 1, 2001, Enron announced the written commitments for an additional $1 billion from JP Morgan and Citigroup to be supported by loans executed with Transwestern and Northern Natural.[9] The proceeds were to be used by Enron to supplement short term liquidity and to refinance maturing obligations. The commitments were subject to customary terms and conditions, including due diligence. Enron issued a press release announcing the loan commitments and on November 13, 2001, filed a Form 8-K with the SEC describing the 354-day revolving credit facility commitment letters.[10] The Transwestern credit agreement was to be structured such that the proceeds of Transwestern's borrowing would be loaned to Enron, with the banks holding a secured interest in Transwestern's not receivable from Enron.[11] The loan

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7 See Enron Press Release Dated Oct. 25, 2001 (attached hereto as Appendix D).

8 Id.

9 See Enron Press Release Dated Nov. 1, 2001 (attached hereto as Appendix E).

10 See Enron's Form 8-K Filing (Nov. 13, 2001) (attached hereto as Appendix F).

11 See Appendix F, supra, Annex I, Covenants.

was structured to accommodate the banks' requirement that, to the extent Enron developed future credit rating difficulties, Enron's access to cash from Transwestern under a separate Cash Management Agreement (between Enron and Transwestern) would be subject to limitations. Specifically, the loan agreement between the Banks and Transwestern provided for a prohibition on inter-company loans or advances in the event of continuing default by Transwestern or when the sum of Transwestern's unrestricted cash and the unutilized borrowing capacity under the Credit Facility after giving effect thereto is less than $10,000,000, or when Enron is no longer investment grade.[12]

Within a week of obtaining the $1 billion loan commitment, Enron issued a press release on November 8, 2001 confirming discussions with Dynegy, Inc. ("Dynegy") regarding a possible business combination transaction.[13] Enron also provided additional information on November 8 by filing a Form 8-K Report setting forth related party and off-balance sheet transactions.[14] The Form 8-K filing provided information, among other things, regarding a required restatement of prior period financial statements to reflect a previously disclosed $1.2 billion reduction to shareholders' equity, as well as various income statement and balance sheet adjustments required as the result of a determination by Enron and its auditors that certain off-balance sheet entities

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12 See id., Annex I, Covenants.

13 See Enron Press Release Date Nov. 8, 2001 (attached hereto as Appendix G).

14 See Enron's Form 8-K Filing (Nov. 8, 2001) (attached hereto as Appendix H).

should have been included in Enron's consolidated financial statements in accordance with GAAP.[15]

Against this backdrop, Enron and Dynegy announced their definitive agreement for the merger of the two companies on November 9, 2001.[16] Dynegy's current stockholders (including ChevronTexaco Corp.) were to own approximately 64% and Enron's stockholders were to own approximately 36% of the combined company's stock at closing, a ratio that implied an approximate $4 billion market capitalization for Enron.[17] The transaction was unanimously approved by the boards of both companies.[18]

On November 13, 2001, the agreements between the Banks, Transwestern and Enron were executed.[19] Enron filed with the SEC its third quarter 10-Q on November 19, 2001. That filing included a restatement of past period earnings and a disclosure that it was attempting to restructure a $690 million obligation that could become due on November 27, 2001.[20] Enron also reaffirmed through a press release its commitment to the merger with Dynegy.[21] In addition, Enron announced that it was involved in active discussions with its primary lenders on

15 See Enron Press Release Dated Nov. 8, 2001 (attached hereto as Appendix I).

16 See Enron Press Release Dated Nov. 9, 2001 (attached hereto as Appendix J).

17 Id.

18 Id.

19 See Transwestern Pipeline Co. Credit Agreement With Citicorp North America, Inc. and Citicorp North America, Inc. and JP Morgan Chase Band (Nov. 13, 2001) (attached hereto as Appendix K).

20 See Enron Press Release Dated Nov. 19, 2001 (attached hereto as Appendix L).

21 See Enron Press Release Dated Nov. 21, 2001 (attached hereto as Appendix M).

a restructuring of its debt obligations to further enhance its financial stability.[22] As of the time of the subject loan transaction, Transwestern senior management reasonably believed that Transwestern had taken steps to fairly and reasonably adjust its capital structure in a loan transaction that had and would, along with other events, result in a material assist in avoiding an irreparable financial crisis for its parent company.

Conditions Deteriorated Rapidly Leading to Enron's Bankruptcy

The conditions that existed during the consideration, negotiation and execution of the loan transaction deteriorated and then changed suddenly and dramatically on November 28, 2001. On that date, Dynegy provided notice to Enron of its immediate termination of the proposed merger, which prompted S&P and Moody's to downgrade Enron's long-term debt to below investment grade.[23] Enron announced in a press release on this same day that it was taking actions designed to preserve value in the company's core trading and other energy businesses, including the temporary suspension of all payments other than those necessary to maintain core operations.[24] On November 29, 2001, Enron announced that it was re-evaluating whether previously announced dividends would be paid.[25] This announcement was associated with Enron's plans to take actions necessary to preserve value in its core energy businesses.

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22 Id.

23 Although the matters have now been resolved by settlement, the facts related to and leading up to the Dynegy termination of the merger agreement are set forth in the Complaint for Declaratory Relief and Damages filed by Enron Corp., et al., against Dynegy Inc. and Dynegy Holdings, Inc. in the United States Bankruptcy Court, Southern District of New York (attached hereto as Appendix N).

24 See Enron Press Release Dated Nov. 28, 2001 (attached hereto as Appendix O).

25 See Enron Press Release Dated Nov. 29, 2001 (attached hereto as Appendix P).

On December 2, 2001, Enron filed for voluntary Chapter 11 reorganization with the United States Bankruptcy Court for the Southern District of New York.[26]

III. THE COSTS AND INDEBTEDNESS ASSOCIATED WITH THE LOAN WERE PRUDENTLY INCURRED.

The Commission's Order to Respond directed Transwestern and Northern Natural to demonstrate "why the costs and indebtedness associated with loans totaling approximately $1 billion made by the pipelines with Citicorp North America, Inc. (Citicorp) and JP Morgan Chase Bank (JP Morgan) within two weeks of Enron filing for Chapter 11 reorganization under the Federal Bankruptcy Code were not imprudently incurred and therefore unrecoverable by the pipelines in any future rate proceedings before this Commission." Order to Respond at 1. Without analysis the Commission states simply that it "appears" Transwestern's decision to enter into the loan agreement was imprudent. From the Order as a whole, this conclusion seems to be tied directly and solely to the close proximity of the loan agreement to Enron's filing for bankruptcy on December 2, 2001. As shown below, at the time the decision to enter into the loan agreement was being considered and entered into – mid-October through mid-November 2001 – Transwestern's decisions were demonstrably prudent.

A finding by the Commission that Transwestern management's decision making surrounding the $550 million loan was tainted by imprudence can be supported, if at all, only when based on hindsight or prescience or both. Under established law, however, the Commission is required to focus exclusively on whether it was reasonably prudent for a pipeline management to enter into the loan agreement at the time the loan agreement was negotiated and entered into. The prudence standard under Sections 4, 5 and 7 of the Natural Gas Act ("NGA") is based on a "reasonable utility management" test which is highly deferential to management

26 See Enron Press Release Dated Dec. 2, 2001 (attached hereto as Appendix Q).

decisions.[27] Under the "reasonable utility management" test, the Commission must determine whether the business decisions Transwestern made are the type of decisions that a reasonable utility management would have made, in good faith, under the same circumstances and at the same relevant point in time. In addition, the standard requires that the Commission apply a rebuttable presumption that Transwestern's management acted prudently in entering the loan transaction.

A. There is No Clear Statutory Basis for the Order.

As a threshold matter, the Commission Order is not clear on the statutory basis for its actions. Indeed, while the Commission refers to its authority under Sections 5, 7 and 16 of the NGA, those provisions do not provide express authority for the Commission's Order. Order to Respond at 1. What is clear is that the Commission is not initiating a rate proceeding under Section 5 and the Commission has made no finding that Transwestern's existing rates are anything but just and reasonable rates. In fact, none of the costs associated with the loan in question were included in any prior rate proceeding and, in particular, they were not included in the rate proceeding in Docket No. RP95-271-000, et al., which formed the basis for Transwestern's existing rates. Under the settlement approved by the Commission in that proceeding, existing rates are to remain in effect until the filing of a new rate case under Section 4, which must be filed to be effective by November 1, 2006.[28] Until Transwestern initiates its next general rate proceeding, no lawful determination can be made by the Commission with

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27 Violet v. FERC, 800 F.2d 280, 283 (1st Cir. 1986) (affirming New England Power Company, 31 FERC ¶ 61,047 (1985)); see City of New Orleans v. FERC, 67 F.3d 947 (D.C. Cir. 1995) (applying prudence standard articulated in Violet). Even in cases in which the prudence standard is not an issue, federal courts have recognized the broad discretion that utility's possess concerning the disposition of profits. See generally, City of Charlottesville v. FERC, 774 F.2d 1205, 1218 (D.C. Cir. 1985).

28 Transwestern Pipeline Co., 72 FERC ¶ 61,085 (1995).

respect to any cost component of Transwestern rates since no rate change proceeding is pending before the Commission. Additionally, in the context of any general rate change proceeding, the Commission must consider all relevant costs, not just one single component, as the Commission appears to be doing here.[29]

Similarly, the Commission's Order does not bring into play any aspect of Section 7 of the NGA. The Order does not concern a request for a Certificate of Public Convenience and Necessity nor is there any pending request for abandonment authorization associated with Transwestern's jurisdictional facilities.

To the extent Section 16 is intended as the basis for the Order, this would seem to apply, at best, to the enforcement of the Commission's accounting requirements under the Uniform System of Accounts for natural gas companies. While Transwestern does not believe it has run afoul of the Commission's Uniform System of Accounts as is demonstrated in the next section of this response, the fact is that Transwestern has been involved in an audit by the Commission's accountants which is ongoing. To date, the Commission's auditors have been the recipient of responses from Transwestern to data requests on numerous occasions including responses that were provided subsequent to the issuance of the Commission's Order in this proceeding.[30] The audit staff has not, to the best of Transwesten's knowledge, completed their final report on the

29 The Commission has an established policy against piecemeal ratemaking. See, e.g., Williston Basin Interstate Pipeline Co., 74 FERC ¶ 61,081, at 61,250 (1996); CNG Transmission Corp., 63 FERC ¶ 61,330, at 63,192 (1993).

30 Transwestern's most recent data response to the Audit Staff's 31st and 32nd written requests was provided on August 26, 2002.

audit and is continuing its review of Transwestern's books and records.[31] Under these circumstances, the underlying statutory basis for the August 1 Order is unclear.

While the basis for the Commission's Order is doubtful, Transwestern nonetheless seeks here to respond to the factual matters raised by the Order to Respond. Transwestern does not believe the Commission's Order reflects all of the salient facts associated with Transwestern activities and Transwestern desires to clear the air with respect to this and any allegation regarding the prudence of its actions.

B. Transwestern's Actions Were Demonstrably Prudent Under the Applicable Standard.

While the Order to Respond does not identify the applicable standard to be applied in judging the prudence of Transwestern's actions in entering into the loan agreement with Enron, it is axiomatic under established precedent that the Commission apply the "reasonable utility management" test.[32] The "reasonable utility management" standard for prudence determinations provides that:

> "[M]anagers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers. In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and at the relevant point in time.

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31 Part 158 of the FERC's regulations provides that a notice of deficiency will be issued based on an examination by a representative of the Commission's accounting department. 18 C.F.R. § 158.1 (2002). Under this procedure, Transwestern is entitled to an opportunity to respond to a notice of deficiency. 18 C.F.R. § 158.2 (2002). The audit staff has not issued a deficient notice to date.

32 The Commission applies the "reasonable utility management" standard of prudence under the both FPA and the NGA. See National Fuel Gas Supply Corp. v. FERC, 900 F.2d 340, 347 (D.C. Cir. 1990) (affirming the Commission's finding that National Fuel's purchases of high cost gas for off-system sales were imprudent) (citing New England Power Co., 31 FERC ¶ 61,047, at 61,084 (1985), aff'd sub nom. Violet v. FERC, 800 F.2d 280 (1st Cir. 1986)); see also Metzenbaum v. Columbia Gas Transmission Corp., Opinion No. 25, 4 FERC ¶ 61,277, at 61,621 (1978) (applying test under which the Commission must examine the incurrence of costs from the perspective of the company at the time when the decisions were made).

See Violet, 800 F.2d at 282-83 (quoting New England Power Co., 31 FERC ¶ 61,047, at 61,084 (1985) (emphasis in original).[33] The Violet court placed great emphasis on the fact that the Commission could not consider subsequent events in reaching its prudence determination. In this regard, the First Circuit held that "while in hindsight it may be clear that a management decision is wrong, our task is to review the prudence of the utility's actions and the costs resulting therefrom based on the particular circumstances existing at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenditures." Id. at 283.

Furthermore, the standard is no different when applied to intra-corporate transactions. In Panhandle Eastern Pipe Line Co., the Commission reversed an ALJ's finding that Panhandle's purchases of gas from its affiliate Trunkline Gas Company were imprudent.[34] The Commission explained in applying the prudence standard to an intra-corporate transaction that:

> In determining whether certain expenditures are prudent, the Commission has formulated the reasonable person standard, which it articulated in New England Power Company. The Commission stated that while utility managers have broad discretion in the conduct of their business affairs, "the appropriate test to be used is whether they are costs which a reasonable utility management (or that of another jurisdictional entity) would have made, in good faith, under the same circumstances, and the relevant point in time." The Commission cautioned that while hindsight may reveal that a management decision was wrong, the prudence determination is "based on the particular circumstances existing either at the time the challenged costs were actually incurred, or the time the utility became committed to incur those expenses."

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33 In Violet, the First Circuit affirmed the Commission's decision that New England Power Company did not act imprudently in continuing to invest in a nuclear power plant after the date that the Massachusetts Department of Public Utilities determined that the primary owner should have cancelled the project.

34 Panhandle Eastern Pipe Line Co., Opinion No. 313, 44 FERC ¶ 61,246, at 61,910 (1988), reh'g denied, Opinion No. 313-A, 46 FERC ¶ 61,189 (1989).

Id. at 61,911 (footnote omitted).[35] The same reasoning must be applied to Transwestern in the instant case.

1. A Reasonable Pipeline Management Would Have Reached the Same Decision During the Mid-October 2001 through Mid-November 2001 Time Period.

The prudence standard's requirement that the Commission disregard events which occur after the management decision leading to cost incurrence is made is crucial to the Commission's deliberative process here. The Commission must consider Transwestern's decision to enter into a loan agreement based upon the known facts available for consideration at that time.

Known Material Facts and Due
Diligence During the Operative Time Period

Transwestern exercised reasonable judgment with respect to its decisions regarding the subject loan. At the time, Transwestern's sole shareholder, Enron, was experiencing financial difficulties. This is hardly in dispute. However, at that time Transwestern believed Enron was a viable, going concern with investment grade debt ratings from all major financial rating entities. Transwestern and other Enron interstate pipeline subsidiaries were approached by Enron in mid-October of 2001 regarding whether they possessed the debt capacity to allow them to provide financial support to support. As a result, a commitment letter regarding the subject loan was entered by Transwestern on October 31, 2001, and the loan was closed on November 13, 2001. Consequently, the appropriate time period in which Transwestern's business decisions must be considered is mid-October through mid-November 2001.

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35 See also Northwest Pipeline Corp., Opinion No. 340, 49 FERC ¶ 61,370, at 62,344, 62,346 (1989) (rejecting the FERC Staff's arguments that Northwest's decision to enter into certain gas supply contracts was imprudent because "Northwest should have insisted upon buyer protection conditions and better pricing provisions . . ., and if unable to obtain these conditions, Northwest should have walked away from the bargaining table") (citing Northwest Central Pipeline Corp., 44 FERC ¶ 61,222, at 61,821 (1988); Acker v. United States, 298 U.S. 426, 430 (1936)) (footnotes omitted).

Transwestern decided to enter into negotiations to provide a loan to Enron based in part on the fact that Transwestern had substantial capacity for leverage because its capital structure was then essentially 100% equity.[36] But this was only one element of Transwestern's overall decision making process. Indeed, during the mid-October through mid-November 2001 period, Transwestern management took the following known material facts into account in the process of rendering its decision regarding the loan agreement and, at a minimum, the Commission must consider such facts:

(1) Although Enron had been experiencing financial difficulties, its credit rating remained investment grade throughout the relevant time period.

(2) Enron signed a definitive merger agreement with Dynegy in early November, which until late in November appeared to ensure Enron's survival, even under the worst case scenario.

(3) Dynegy's apparent willingness to merge with Enron and take on all of Enron's assets and liabilities provided further assurances of the future economic well being of the combined Enron-Dynegy.

(4) The loan negotiations between Transwestern and the Banks were conducted at arms length. Transwestern's Board of Directors duly approved the loans through appropriate resolutions and opinions.

(5) The $550 million loan involved short term debt that generally would not be included in Transwestern's capital structure for regulatory purposes.

(6) At the time it was closed, the loan could be made without jeopardizing Transwestern's capital structure and without unduly increasing credit risk.

(7) Teams from Enron corporate finance, Transwestern and the banks conducted thorough financial due diligence of income and cash flows on a historical and projected basis with respect to Transwestern's ability to make and retire the loan in reasonable fashion.

(8) Transwestern believed the principal amount being loaned to Enron would be recoverable by the loan's due date, along with interest as a contribution toward earnings of Transwestern.

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36 See FERC Form 2 at 112-113 (Dec. 31, 2001).

(9) The loan was structured under the banks' requirement that to the extent Enron developed future credit rating problems, Enron's access to cash from Transwestern under a separate Cash Management Agreement between Enron and Transwestern would be limited.

(10) Transwestern's actions were consistent with its corporate and fiduciary responsibilities to its shareholders under the Delaware Corporate Law.

Along with these salient facts, Transwestern believed at the time of the loan that it would be making a substantial contribution towards assuring Enron's survival. Conversely, an Enron bankruptcy filing, although not the likely scenario from the perspective of Transwestern's management in early November of 2001, was a result to be avoided if at all possible, consistent with Transwestern's obligations. The failure to act and potential further deterioration of its parent company was a result that prudent pipeline managers should have, and did in this case, take reasonable steps to avoid. The fact that subsequent events proved Transwestern's efforts to have been too little, too late, is immaterial under the prudence standard. Moreover, Transwestern actions in entering into the loan arrangements did not jeopardize its own viability. Indeed, the fact is that Transwestern had the financial wherewithal to handle the debt without difficulty. Its capitalization was 100% equity at the time and the loan arrangements were structured to protect Transwestern. Given the need of Transwestern's parent/shareholder for financial assistance at the time, Transwestern actions were demonstrably prudent.

Viewed in proper context, Transwestern acted as a reasonable pipeline would have under the circumstances and entered into the loan agreement. Assuming that a different conclusion might have been reached with the benefit and clarity of hindsight, this is of no consequence for purposes of legal analysis under the established prudence standard. Unfortunately, Enron's situation deteriorated rapidly when the merger deal with Dynegy terminated abruptly on

November 28, 2001 upon the receipt of notice from Dynegy. On that same date, S&P and Moody downgraded Enron below investment grade. These events unfolded after Transwestern executed the loan agreements with the Banks and Enron. Short of clairvoyance, these events could not reasonably have been foreseen and predicted by Transwestern. Moreover, even if those eventualities could (with hindsight or otherwise) have been seen as more likely than not, a reasonably prudent pipeline manager should have endeavored to make the attempt to forestall a financial collapse as Transwestern's management did.

2. FERC Cannot Substitute its Judgment for that of Transwestern.

The Commission is required under the law to refrain substituting its judgment for that of the directors of the corporation. In the present case, the Commission's obligation is to not engage in micro-management of the business affairs of Transwestern with respect to decisions made during the operative period.[37] This fundamental principle of law is well established. In Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, the Supreme Court, in reversing the Public Service Commission's disallowance of Southwestern Bell's recovery of certain expenses in its rates, held that:

> It must never be forgotten that, while the state may regulate with a view to enforcing reasonable rates and charges, it is not the owner of the property of public utility companies, and is not clothed with the general power of management incident to ownership. The applicable general rule is [that] "[t]he commission is not the financial manager of the corporation, and it is not empowered to substitute its judgment for that of the directors of the corporation; nor can it ignore items charged by the utility as operating expenses, unless there is an abuse of discretion in that regard by the corporate officers."

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37 In Midwestern Gas Transmission Co., the Commission emphasized that it is not the Commission's duty under the NGA to manage the business affairs of natural gas companies. Midwestern Gas Transmission Co., 36 FPC 61, reh'g denied, 36 FPC 599 (1966), aff'd, Midwestern Gas Transmission Co. v. FPC, 388 F.2d 444 (7th Cir.), cert. denied, 392 U.S. 928 (1968).

262 U.S. 276, 289 (1923) (quoting States Public Utilities Comm'n ex rel. Springfield v. Springfield Gas & Elect. Co., 291 Ill. 209, 234, 125 N.E. 891, 901) (emphasis added) (citation omitted). This seminal case provides that the Commission cannot substitute its judgment for that of the regulated utility in the area of business expenditures.[38] Therefore, pursuit by the Commission of a course to take the corporate reins and determine by proxy what decisions "should" have been made during the mid-October through mid-November 2001 period would be contrary to law.

3. A Rebuttable Presumption of Prudence Must be Applied.

The Commission's Order to Respond appears on its face to view Transwestern's decision to enter into the loan agreement as being presumptively imprudent. Any presumption of imprudence has no place under the law. In West Ohio Gas Co. v. Public Utilities Commission of Ohio, the Supreme Court, in reversing the Public Utilities Commission's reduction of West Ohio's recoverable operating expenses, held that:

> Good faith is to be presumed on the part of the managers of a business. In the absence of a showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay.[39]

In a more recent case, the D.C. Circuit held that "it has long been settled that a utility's costs are presumed (subject to rebuttal) to be prudently incurred."[40]

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38 See, e.g., Northwest Pipeline Corp., 32 FERC ¶ 63,069, at 65,205 (1985) (citing Missouri ex. rel. Southwestern Bell Telephone Co. v. Missouri Public Serv. Comm'n, 262 U.S. at 289; Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n, 262 U.S. 679, 693 (1923); West Ohio Gas Co. v. Public Util. Comm'n, 294 U.S. 63, 73 (1934)), aff'd, 38 FERC ¶ 61,302, at 61,988 (1987); see also Anaheim, Riverside, Banning, Colton, and Azusa, California v. FERC, 669 F.2d 799, 809 (D.C. Cir. 1981); Violet v. FERC, 800 F.2d 280, 282 (1st Cir. 1986).

39 295 U.S. 63, 72 (1934) (citing Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Serv. Comm'n, 262 U.S. at 289) (citations omitted).

These cases illustrate that application of a rebuttable presumption to utility decisions to incur costs is required in this proceeding. Federal appellate courts and regulatory commissions are required to presume utility management decisions are prudent unless rebutted by prima facie evidence to the contrary.[41] The Commission is required to apply this long standing principle of law in the instant case, yet the conclusion of imprudence articulated in its Order to Respond, if made final, violates this standard. No prima facie evidence has been produced by the Commission to rebut the presumption that Transwestern's incurrence of the indebtedness and costs associated with the loan agreement were anything but prudent.

C. The Loan is Rate Neutral.

Along with the foregoing considerations, the Commission should also take into account the fact that the loan transaction will have no impact on future rates. Transwestern's existing rates are the result of a settlement approved by the Commission on July 27, 1995 in Docket Nos. RP95-271-000, et al., which resolved potential litigation issues arising from Southern California Gas Company's ("SoCal") intended relinquishment of 475,281 Dth/d of capacity on Transwestern's system effective November 11, 1996. Transwestern Pipeline Co., 72 FERC ¶ 61,085 (1995). The settlement established rates to be effective November 1, 1996. The settlement requires Transwestern to file a new rate case to be effective no later than November 1, 2006.

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40 Ohio Power Co. v. FERC, 880 F.2d 1400, 1413 (D.C. Cir. 1989) (citing Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Public Serv. Comm'n, 262 U.S. at 289; Anaheim v. FERC, 669 F.2d 799, 809 (D.C. Cir. 1981)); see also Northwest Pipeline Corp., 32 FERC ¶ 63,069, at 65,205 (1985), aff'd, 38 FERC ¶ 61,302, at 61,988 (1987) (holding that "[t]here is a rebuttable presumption that a utility's operations were conducted in good faith, consistent with principles of 'efficient and economical management' (citing Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Pub. Serv. Comm., 262 U.S. 276, 289 (1923); Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm. of West. VA, 262 U.S. 679, 693 (1923); West Ohio Gas Co. v. Pub. Util. Comm. of Ohio., 294 U.S. 63, 73 (1934)).

41 Arizona Public Service Co., Opinion No. 219, 27 FERC ¶ 61,185, at 61,351 (1984).

The new rates to be proposed on November 1, 2006 will be based on actual costs for the selected annual period used for the test period of that rate case, adjusted for known and measurable changes so that the costs are reasonably reflective of ongoing future costs. In view of the test period requirements, the costs of the short term loan will not be included in Transwestern's future rates since the loan matures in November 2002.[42] The fees associated with the loan must, under GAAP, be amortized during the term of the loan. Even if the annual period of actual costs included some period of time the loan was outstanding, the adjustment process would require that the loans be excluded from the capital structure because the loan would not be considered to be an ongoing future cost due to its short duration.

The Commission's conclusion that Transwestern "will have significantly higher cost of capital" is without the support of any evidence. By definition, any such conclusion is at best speculative. How and by what means Transwestern may seek to refinance its loan when it comes due in November of this year are matters that are currently under discussion and negotiation and are not known at the present time. As such, they are beyond the scope of this proceeding.[43] The Commission can consider the reasonableness of Transwestern's cost of capital only in the context

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42 See 18 C.F.R. § 154.303(a)(2) (2002).

43 It is well established under the law that general rate filings are made by natural gas pipelines on a voluntary basis. United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332, 343 (1956); Public Serv. Comm'n of New York v. FERC, 866 F.2d 487, 429 (D.C. Cir. 1989); 15 U.S.C. § 717c (1994). The Commission can compel a change in rates that a pipeline already has on file only under section 5 of the NGA. 15 U.S.C. § 717d (1994); Public Serv. Comm'n of New York v. FERC, 866 F.2d at 488; Sea Robin Pipeline Co. v. FERC, 795 F.2d 182, 183-84 (D.C. Cir. 1986). Under section 5, the Commission must initiate a hearing and carry the burden of proof to show that the existing rates are unjust and unreasonable and to "fix" rates which are just and reasonable. 15 U.S.C. § 717d(a) (1994). The Commission cannot circumvent the limitations placed on its rate authority through reliance on other sections of the Act. Northern Natural Gas Co. v. FERC, 827 F.2d 779 (D.C. Cir. 1987); Panhandle Eastern Pipe Line Co. v. FERC, 613 F.2d 1120 (D.C. Cir. 1979), cert. denied, 449 U.S. 889 (1980).

of Transwestern's next general rate proceeding.[44] Such matters are not lawfully before the Commission until then.

Therefore, irrespective of the issue of prudence, the future recovery of the costs of the loan are not an issue.

D. Transwestern Fulfilled its Fiduciary Obligation to Enron Under Delaware Corporate Law.

The loan transaction is completely consistent with the fiduciary duties that the directors of Transwestern owed to Enron. Directors of a corporation have a fiduciary obligation to make business decisions that are in the best interests of the corporation.[45] In situations involving a corporation that is a wholly-owned subsidiary of another corporation, this obligation requires that the directors of the subsidiary corporation manage the affairs of the subsidiary in the best interests of the parent corporation and its stockholders.[46] Accordingly, the directors of Transwestern were required by general corporate director fiduciary obligations to operate Transwestern in the best interests of Enron and its shareholders. The directors of Transwestern were obligated to enter into the loan because the loan transaction was in the best interests of Enron.

44 The ownership and makeup of Transwestern's capital structure for purposes of the next rate case are also currently under discussion and negotiation and not known or knowable at the present time. Pending future approval of Enron's proposed reorganization of assets, including Transwestern, into a new operating enterprise known as "Opco," the Creditors Committee has directed the conduct of an auction process in an effort to determine the appropriate value of various separate businesses including Transwestern. Thus, the only thing know about the future ownership and capital structure of Transwestrem is that it will definitely change and be dramatically different than exists in its present circumstances.

45 Aronson v. Lewis, 73 A.2d. 805 (Del. 1984).

46 Anadarko Petro. v. Pahhandle Eastern, 545 A.2d 1171, 1174 (Del. 1988).

Transwestern's directors had two fiduciary duties to Enron under Delaware Corporate law: the duty of due care and the duty of loyalty. Pursuant to the duty of care, the directors of a Delaware corporation are required to "inform themselves of any material information reasonably available to them,"[47] and then "act with requisite care in the discharge of their duties."[48] As demonstrated in the foregoing section on prudence, Transwestern's board of directors met these requirements to the fullest extent possible. The law provides that a court will not examine the reasonableness of Transwestern's business decisions, so long as those decisions resulted from a reasonable decision-making process. Under this "business judgment" rule, the board of directors is presumed to have made a business decision on an informed basis, in good faith and in the honest belief that the action taken was in the best interests of the company.[49] Therefore, in the absence of a showing of abuse of discretion, fraud, bad faith or illegality, the board's action in question will be upheld, regardless of the wisdom of the action when viewed in hindsight. In other words, courts will not examine whether or not a decision was a good or bad business decision, but will look only at the reasonableness of the decision-making process. Transwestern's directors' decision-making process clearly was reasonable in the instant case.

IV. THE NOVEMBER TRANSACTIONS COMPLY FULLY WITH THE PART 201 ACCOUNTING REGULATIONS.

The Commission's August 1, 2002 Order concluded that "[i]t appears that due to the failure to maintain written cash management agreements with Enron," Transwestern is not able

47 Smith v. Van Gorkom, 488 A.2d 858, 873 (Del. 1985).

48 Aronson v. Lewis, 473 A.2d 805, 812 (Del. 1984).

49 Id. Delaware has not enacted an "other constituency" or "stakeholder" statute, a statute explicitly allowing directors to consider other interests, such as effects on employees or customers, in discharging their duties.

to support entries in Account 146 of the Uniform System of Accounts ("USofA"). Order to Respond at 4. Based on this conclusion, the Commission required Transwestern to show why Transwestern has not violated the General Instructions-Records under Part 201 of the USofA.

The Commission's conclusion that Transwestern did not have a written cash management agreement is factually incorrect: a written promissory note <u>does exist</u>, is currently in the Commission's possession, and its existence has been disclosed numerous time in Transwestern's FERC Form No. 2 annual reports. In addition, even without the written cash management agreement, Transwestern's written documentation of its cash management activity was sufficient to satisfy the requirements of the USofA.

A. Transwestern had a Written Cash Management Agreement in Place and it Was Fully Disclosed to the Commission.

The Commission's concern that Transwestern did not have a written cash management agreement for the Enron loan is unfounded. Transwestern participated in Enron's centralized cash management program during the relevant time period. Transwestern's cash surplus to its daily needs was loaned to Enron on a daily basis under a "zero balance account" mechanism. Transwestern's participation in this centralized cash management system was subject to the terms of a written promissory note between Transwestern and Enron dated May 14, 2001. This promissory note, which is attached hereto, was provided to the Commission's audit staff in the context of the ongoing audit.[50]

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50 A copy of the Amended and Restated Promissory Note from Enron Corp. to Transwestern dated May 14, 2001, is attached hereto as Appendix J. Copies of the promissory note was requested by the Auditors and provided informally by Transwestern during the first week in February 2002.

Subsequently, the Commission audit staff served Transwestern a request for copies of any cash management agreements. Transwestern's written response to that request reflected some confusion about exactly what the audit staff wanted, due in part to the fact that the promissory note had already been provided. Similarly, in

In addition, Transwestern has consistently disclosed the existence of the cash management agreement to the Commission in its FERC Form No. 2 annual reports since 1997. The pertinent disclosure made by Transwestern in its Form No. 2 for the year ended December 31, 2001, is as follows:

> Until December 2, 2001, the Respondent was included in Enron's cash management program. Based on the Respondent's cash availability or requirements, advances were made either to or from Enron. The net result of all of the Respondent's cash flows, including reimbursements to Enron for income tax liabilities, employee benefit plans and various administrative expenses described below, was reflected as "Accounts Receivable from Associated Companies" (account receivable) on the Comparative Balance Sheets. The Respondent received (or paid) interest on its account receivable with Enron, which for 2000 was 6% on the account balance at December 31, 1997 and 9.5% on the account balance accumulated after 1997. Beginning January 1, 2001, the interest rate was calculated on a daily basis at a rate per annum equal to the daily corresponding Fed Funds Rate, less .05%, as published in the Federal Reserve Statistical Release H.15, which ranged from 1.14% to 6.62% for the year ended December 31, 2001. These rates were determined solely by Enron management. Interest income of $20.2 million and $21.7 million was recorded in 2001 and 2000, respectively. No interest expense was recorded in 2001 or 2000.

FERC Form No. 2 at pages 122.11-122.12.[51] In any event, the Commission's assumption that no "written cash management" exists is not correct.

B. The Additional Written Documentation of Transwestern's Participation in Enron's Cash Management Program Complied Fully With the USofA.

A determination of whether Transwestern failed to comply with the instructions of the USofA must rest squarely on the rules in effect in October and November of 2001, as

response to audit staff inquiries it was indicated that there are no separate cash control standards applicable to Transwestern. However, there are "Minimum Cash Control Standards" which have been in effect since October of 2000 and which apply to all Enron subsidiaries, including Transwestern (attached hereto as Appendix R).

51 Transwestern ceased its participation in the cash management program on December 2, 2001, because the Credit Facilities required its termination if Enron ceased to be investment grade.

Transwestern was entitled to rely on the existing regulations until they are changed.[52] A review of the then-effective accounting regulations demonstrates that Transwestern met, if not exceeded, the requirements for documentation of its cash management transactions. Significantly, these regulations remain in effect today.

The sum total of the guidance available to Transwestern at the relevant time is found in General Instruction No. 2 and the text of Account 146 of the USofA. General Instruction No. 2 under Part 201 of the Uniform System of Accounts for natural gas companies reads in pertinent part as follows:

> A. Each utility shall keep its books of account, and all other books, records and memoranda which support the entries in such books of account so as to be able to furnish readily full information as to any item included in any account. Each entry shall be supported by such detailed information as will permit ready identification, analysis, and verification of all facts relevant thereto.

18 C.F.R. Part 201, General Instruction No. 2(A) (2002). The text of Account 146 adds only that:

> Each utility shall keep its accounts and records so as to be able to furnish accurately and expeditiously statements of all transactions with associated companies. The statements may be required to show the general nature of the transactions, the amounts involved therein and the amounts included in each account prescribed herein with respect to such transactions. Transactions with associated companies shall be recorded in the appropriate accounts for transactions of the same nature. Nothing herein contained, however, shall be construed as constraining the utility from subdividing accounts for the purpose of recording separately transactions with associated companies.

18 C.F.R. Part 201, General Instruction No. 14 (2002).

52 See East Tennessee Natural Gas Co. v. FERC, 863 F.2d 932, 945 (D.C. Cir. 1988) (emphasizing that a pipeline has the right "to rely on existing Commission policy . . . until the Commission changed that policy"). New Commission policies are implemented on a prospective basis. Id.

Transwestern's compliance with these instructions was full and complete. Moreover, even if Transwestern did not have a written promissory note under which all daily cash management activity was undertaken, the facts show that Transwestern followed a consistent methodology for managing its cash, and maintained all appropriate documentation of that activity. Cash received from Transwestern's customers was swept, on a daily basis, from Transwestern's Bank of America zero balance account into Enron's master Bank of America account. Transwestern's operating expenses and capital expenditures were made through Transwestern's disbursement accounts at Citibank New York (wires) and Delaware (checks). The Citibank disbursement account was funded on a daily basis from Enron's master Citibank account. The net result of all Transwestern's cash flows was reflected as "note receivable from parent company" on the balance sheet of Transwestern. Each transfer was appropriately reflected in the internal financial records of both Transwestern and Enron. Those records, including bank statements, general ledger entries, and other similar documentation have either been provided to the Commission's Audit Staff already or are available to the Audit Staff upon request in the ongoing audit. Therefore, contrary to the Commission's assumption, Transwestern does possess the required documentation.

The Commission may amend the USofA by issuing a final rule in Docket No. RM02-14-000 requiring a more detailed and specific format of written documentation of money pool arrangements than that followed by Transwestern. However, whatever new regulations emerge from the Commission's rulemaking process have no application to the period of time relevant to this proceeding. Similarly, new Accounting Release No. 17 (issued on August 1, 2002), although providing helpful clarification of the Chief Accountant's interpretation of the USofA, does not apply retroactively to the period during which the subject transactions between Transwestern, Enron, and the Banks were consummated.

Transwestern fully complied with both the letter and spirit of the currently-effective General Instruction No. 2 and Account 146 of Part 201, the operative standards during the subject time period. As a result, there has been no violation of the Commission's accounting regulations in any respect.

WHEREFORE, in view of the foregoing, Transwestern requests that the Commission issue and order finding that its incurrence of costs and indebtedness with respect to the subject loan agreement with Enron was prudent and that it did not violate the USoA with respect to the related entries made in Account 146.

Respectfully submitted,

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Transwestern Pipeline Company

Dated: September 3, 2002

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Date:09/17/02

Committee on Governmental Affairs
EXHIBIT #A-42

Prepared By: Rogers / Wall / Lee

STRUCTURING SUMMARY
Project Bluehorseshoe

GIB Deal Team: Walker, Wall GSF: Teague, Serice, Lee Lender: Traband, Rogers
Credit Executive: Ballentine Timing: October 29, 2001

Maximum Exposure for Approval	$ billion	Industry Description:	Pipelines
Transaction for Approval ($MM):	$600MM Underwrite $150MM Hold	Primary SIC Code:	1321
Customer Name:	Northern Natural Gas Transwestern Pipeline	HQ:	Houston, TX
Obligor/Facility Risk Grade:	5/4	Major Plant Locations:	Texas/Gulf Coast, Oregon
Parent Name:	Enron Corp.	Major Overseas Ops:	Europe, India, Brazil, Argentina, Bolivia, Colombia, Caribbean, Philipp.
Parent Risk Grade:	4/4	TREND:	
Public Ratings (LT & ST):	CP: A2/P2 Sen. Uns: BBB+/Baa1 Sub: BBB/Baa3	Outlook/Trend?	Negative
Stock Price (as of 10/25/01): Market Capitalization:	$16.41 $12.3 Billion	52 Wk High/Low: Market Cap/Book Cap:	$84.88 / $15.51

Executive Summary:

Background:
Enron Corp. ("Enron" or the "Company"), with LTM revenues of $180.5 billion and EBITDA of 4.6 billion, is a holding company with subsidiaries that provide products and services related to natural gas, electricity and communications to wholesale and retail customers. The Company derives the majority of its operating income from its trading operations.

The Company is currently rated BBB+/Baa1 and is on negative outlook from both rating agencies. The stock price closed at $16.41 on 10/25/01 (mkt. cap. of $12.3 billion) which represents a 50% decrease from the prior week and an 80% drop from January 2001. The stock price initially dropped in the beginning of the year due to the following reasons: 1) the Company was among the companies exposed to the California Energy crisis, 2) the Company's broadband unit did not meet expectations 3) Enron had a dispute regarding tariffs and payments with its Dabhol power station in India, resulting in the suspension of power generation 4) CEO Jeff Skilling abrubtly stepped down as CEO in August 2001 after having been promoted to the job eight months earlier 5) A net loss of $638 million in the third quarter which included a $1 billion charge from investment losses and 6) the effective repurchase of stock and associated $1.2 billion write down of equity as a result of unwinding certain structured transactions entered into with LJM2 limited partnership and 7) recent SEC inquiries about possible conflict of interest issues concerning the then CFO, Fastow, and his role in the LJM2 partnerships.

Liquidity Issues:
Due to the issues highlighted above, Enron has found itself with progressively less access to various capital markets, culminating in an inability to roll the maturing portion of $2.2 billion in outstanding commercial paper. As a result, on Thursday, October 25, Enron drew 100% of its $3 billion in committed commercial paper back-up facilities. Net of outstanding commercial paper, this left the company with $1 billion in cash liquidity. As of the close of business Friday October 26, Enron had $ MM, net of ouststanding CP. Based on current daily cash projections (see Exhibit A), the Company will have $ MM in cash on December 31, 2001. This includes proceeds from asset sales of $ MM. In 2002 the Company has $ MM in debt maturities and expected asset sales of $ MM, including the announced sale of PGE. The Company is now faced with 1) a significant short-term maturity schedule, 2) uncertainty as to margin swings in its trading business, and 3) the concern that counterparties could replace margin cash currently posted with Enron with letters of credit. Additionally, the Company would be faced with up to $1.5 billion in additional margin it would have to post in the event it lost its investment grade credit rating. (Currently Enron is rated BBB+/Baa1; however, it is under negative watch by both S&P and Moody's.). The maturity schedule below illustrates the extent and timing of the Company's potential liquidity problems:

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Amortization	Outstandings					
B/S Debt-Short	3,009.48					
B/S Debt-Long Term	9,677.41	239.0	15.0	575.0	310.0	0.0
Preferred Stock	903.56	0.0	0.0	0.0	0.0	0.0
Structured	4,698.64	25.3	33.7	76.5	2,773.7	26.2
Minority Interest	1,874.00	0.0	0.0	0.0	0.0	0.0
Securitizations /FAS 140s	2,097.44	22.6	371.2	538.7	191.0	308.5
Prepays	5,115.26	420.7	309.0	194.5	307.8	428.0
Leases	539.68	0.0	308.5		0.0	0.0
Total	27,915.48	457.6	1,287.4	1,384.7	3,582.5	762.8

The existing facilities consist of a $1.75 billion 364-day facility which is priced at L+45 bps drawn and 8 bps undrawn and expires in May 2002 and a $1.25 billion 5-year facility which matures in May 2005 and is priced at L+45 bp and 8 bps undrawn. There is also a $500 million Standby LC facility that is close to fully utilized..

<u>Request:</u>
The Company has asked JPMorgan and Citi/SSB (existing Agents on its $3 billion in Senior Credit Facilities) to arrange and underwrite $1 billion of incremental financing at the pipeline operating companies (Northern Natural Gas ("NNG") and Transwestern ("TW")) which would be committed to by Monday morning, October 29. The financing would be structured as two separate but identical facilities of [$550 million] for NNG and [$650 million] for Transwestern.

Transaction Overview:

Borrower: Northern Natural Gas and Transwestern held through bankruptcy remote subsidiaries

Guarantor: Enron Corp.

Security: Stock of NNG and TW respectively and pledge of assets

Facilities: $550 million in the NNG facility
$650 million in the TW facility

Tenor: 364 day

Covenants: Limitation on additional debt
Debt/Capital

Undrawn: 50.0 bps

Drawn: 250.0 bps

Ave. Fees To Market: 125.0 bps

Co-Admin Agents: JPM / Citi

We believe that the Company can finance approximately $550 million at Northern Natural Gas ("NNG") and $650 million at Transwestern Pipelines ("TW") currently. NNG has approximately $225 million of EBITDA and $500 million of debt while TW has approximately $130 million of EBITDA and $15.4 million of debt.

We would approach Enron's top relationship banks to syndicate this facility. The Arrangers would aim for a target hold of [$150] million and we would ask other top relationship banks to commit [$100] million each and we would also have a $50 million tier. We would require unlimited price and structure flex to fill out the deal.

Corporate Structure:

[STRUCTURE TO BE INSERTED]

Two bankruptcy remote entities ("BRE's"), with outside Board representation, will be created in the context of the transactions. The bank loan will be to TW and NNG, which will in turn intercompany loan the funds to Enron Corp. The stock of TW and NNG will be pledged to the Lenders. Guarantors will be Enron Corp. and the BRE's. The assets are at TW and NNG. TW and NNG have no subsidiaries and are prohibited from creating such. TW and NNG are regulated pipeline entities, which have a significant degree of "separateness" from Enron Corp. For years, cash from the pipelines has been used to support operations at Enron Corp.

Cash Flow Projections:

Northern Natural

CREDIT STATISTICS:	PF 2001	2002	2003	2004	2005	2006	2007	2008	2009
EBITDA	$223.6	$255.0	$262.9	$270.0	$272.1	$274.2	$274.5	$274.8	$275.1
Interest Expense	$60.9	$60.9	$60.9	$60.9	$57.4	$54.0	$54.0	$48.9	$43.9
Capital Expenditures	$89.7	$66.1	$56.9	$49.2	$49.6	$49.8	$49.8	$49.8	$49.8
Senior Debt	$1,049.7	$1,049.7	$1,049.7	$1,049.7	$949.7	$949.7	$949.7	$799.7	$799.7
Total Senior Debt	$1,049.7	$1,049.7	$1,049.7	$1,049.7	$949.7	$949.7	$949.7	$799.7	$799.7
Senior Debt/EBITDA	4.70x	4.12x	3.99x	3.89x	3.49x	3.46x	3.46x	2.91x	2.91x
Total Debt/EBITDA	4.70x	4.12x	3.99x	3.89x	3.49x	3.46x	3.46x	2.91x	2.91x
Debt/Capitalization	49.3%	47.4%	45.6%	43.8%	39.6%	38.0%	36.4%	31.1%	29.7%
EBITDA/Interest	3.67x	4.19x	4.32x	4.44x	4.74x	5.08x	5.08x	5.61x	6.27x
EBITDA-CAPEX/Interest	2.20x	3.10x	3.38x	3.63x	3.87x	4.16x	4.16x	4.60x	5.13x

Transwestern Pipeline

CREDIT STATISTICS:	PF 2001	2002	2003	2004	2005	2006	2007	2008	2009
EBITDA	$132.6	$143.1	$158.0	$174.5	$192.6	$212.7	$212.9	$213.2	$216.7
Interest Expense	$32.5	$32.5	$32.5	$32.5	$32.5	$32.5	$32.5	$32.5	$32.5
Capital Expenditures	$67.8	$54.2	$43.3	$34.6	$34.6	$34.8	$34.8	$34.8	$34.8
Senior Debt	$665.5	$665.5	$665.5	$665.5	$665.5	$665.5	$665.5	$665.5	$665.5
Total Senior Debt	$665.5	$665.5	$665.5	$665.5	$665.5	$665.5	$665.5	$665.5	$665.5
Senior Debt/EBITDA	5.02x	4.65x	4.21x	3.81x	3.45x	3.13x	3.13x	3.12x	3.07x
Total Debt/EBITDA	5.02x	4.65x	4.21x	3.81x	3.45x	3.13x	3.13x	3.12x	3.07x
Debt/Capitalization	39.9%	38.8%	37.3%	35.8%	34.1%	32.4%	30.8%	29.4%	27.9%
EBITDA/Interest	4.09x	4.41x	4.87x	5.38x	5.94x	6.55x	6.56x	6.57x	6.68x
EBITDA-CAPEX/Interest	2.00x	2.74x	3.53x	4.31x	4.87x	5.48x	5.49x	5.50x	5.60x

Selected Enron Structured Transactions:

(See Appendix for description of other transactions)

<u>Marlin Water Trust</u>

- US$475 million and Euro 515 million
- 2 year term

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- Rated Baa1 / BBB
- Proceeds used to fund the Wessex acquisition on a non-dilutive off-credit basis to Enron
- Accomplishes deconsolidation of a non-core business
- Principal is repaid through 1) the sale of assets, 2) the redemption of Enron Mandatorily Convertible Preferred Stock or 3) additional equity raised by Enron (Enron Remarketing Agreement).

Osprey Trust

- US$2,435 million and Euro 515 million
- Matures Jan 2003
- Rated Baa2/BBB
- Used as a vehicle to efficiently monetize investments and raise capital for continued growth
- Principal is repaid through 1) an Enron Share Settlement Agreement, 2) the redemption of Enron Mandatorily Convertible Preferred Stock or 3) the sale of assets valued at US$2.1 BN.
- Assets under the structure include $1.2BN in international assets and $922MM in domestic assets.

Yosemite

- US$750 million and £200 million
- BBB+/Baa1

Enron Liquidity Overview:

Free Cash Flow Summary

		Q4 '01*	Q1 '02	Q2 '02	Q3 '02	Q4 '02
EBITDA		654.1	1,166.4	1,134.0	1,059.6	1,183.8
Cash taxes		(109.0)	(123.6)	(123.2)	(116.1)	(118.5)
Cash interest		(234.3)	(207.1)	(209.0)	(221.5)	(259.9)
Changes in Working capital		128.2	15.6	(22.7)	53.3	(8.8)
Net changes in price risk mgmt (excl. prepays)		421.7	(266.5)	(541.8)	1,022.0	914.8
Net Capital expenditures		(291.6)	(231.3)	(241.2)	(182.4)	(164.5)
Sale of investments		1,026.2	433.8	37.8	35.0	2,225.8
Margin calls		0.0	0.0	0.0	0.0	0.0
Cash available to Repay Debt		1,595.3	787.3	33.9	1,649.9	3,772.7
Cumulative Cash Available		*1,595.3*	*2,382.5*	*2,416.5*	*4,066.3*	*7,839.1*
Amortization	*Outstandings*					
B/S Debt-Short	3,009.48					
B/S Debt-Long Term	9,677.41	239.0	15.0	575.0	310.0	0.0
Preferred Stock	903.56	0.0	0.0	0.0	0.0	0.0
Structured	4,698.64	25.3	33.7	76.5	2,773.7	26.2
Minority Interest	1,874.00	0.0	0.0	0.0	0.0	0.0
Securitizations /FAS 140s	2,097.44	22.6	371.2	538.7	191.0	308.6
Prepays	5,115.26	420.7	309.0	194.5	307.8	428.0
Leases	539.68	0.0	308.5		0.0	0.0
Total	27,915.48	457.6	1,287.4	1,384.7	3,582.5	762.8
RC (draw)/repayment		1,137.7	(500.1)	(1,350.8)	(1,932.7)	3,009.9
RC balance		1,862.3	2,362.4	3,713.2	5,645.8	2,635.9

**For daily cash balances refer to separate attachment*

CHASE

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Pipeline Business:

Northern Natural Gas Company

Northern Natural Gas Company ("Northern") is an indirect wholly-owned subsidiary of Enron Corp. ("Enron"). Northern owns and operates an approximately 16,500 mile interstate natural gas pipeline system with market-area peak capacity in excess of 4.3 Bcf per day and three gas storage fields with over 45 Tbtu of working gas storage capacity available for contract storage services and two liquified natural gas storage peaking units. These storage facilities provide Northern the operational capacity to balance its system on a daily basis and assist in meeting customers' heating season system requirements. Northern's pipeline system stretches from West Texas through the Midcontinent region to several states in the upper Midwest including Iowa, Illinois, Kansas, Michigan, Minnesota, Nebraska, South Dakota, and Wisconsin. Northern provides transportation and storage services to approximately 90 utility customers and end-users in the upper midwestern United States. 90% of Northern's revenues are comprised of monthly demand charges that are based on contracted capacity and do not vary based on throughput. Of the remainder, approximately 8% is firm commodity transport based on postage stamp rates, with the remaining 2% consisting of interruptible service.

Northern operates under a FERC regulated tariff that is designed to allow it the opportunity to recover its costs together with a regulated return on equity. On April 16, 1999, Northern filed a rate settlement with the FERC. The settlement provided for increased seasonality in Northern's rate design effective November 1, 1999, for the Market Area and Field Area. In addition, the settlement provides for other revisions to the Company's transportation and storage services, as well as contract extensions under Northern's firm transportation and firm storage rate schedules. The increased seasonality and service structure under the Settlement recognizes the market value of capacity for the peak heating season and changes in the marketplace due to LDC unbundling. Subject to certain limitations, the settlement provides Northern's customers with rate certainty and stability of cash flows by including a moratorium through October 31, 2003. There are no contracts with shippers that can be renegotiated prior to 2003. During 2003, approximately 1.5 Bcf/day is up for contract renegotiation. Northern has a right of first refusal for the contracts to meet any bonafide contract negotiated for transportation in the area.

Operating Statistics
Total volumes transported (Bbtu/d)

2000	1999	1998
3,529	3,820	4,098

Tariffs and Regulated Rates of Return
($ MM)

Year End 2000 Rate Base	1,064
Regulated Capital Structure	42.00% debt
	58.00% equity
ROIC	10.35%
ROE	12.27%

Northern Natural Gas Company Top 10 Customers
(In $MM for the months October 2000 through September 2001)

Customer	*Revenues*	*% total*	*Volumes*	*% total*	*Ratings*	*Contract maturity*
Reliant Energy Minnegasco	$83.8	18.2%	203.8	10.8%	BBB+*	10/31/07
Utilicorp United	55.4	12.0%	136.2	7.2%	BBB	various to 05
Northern States Power Co. – Minnesota	44.6	9.7%	84.1	4.4%	A-*	various to 12
MidAmerican Energy Company	44.0	9.5%	111.1	5.9%	A	05/31/03
Metropolitan Utilities District	19.5	4.2%	37.7	2.0%	NR	05/31/03
NICOR Gas Company	15.6	3.4%	60.4	3.2%	AA	various to 04
ANR Pipeline Company	11.7	2.5%	39.7	2.1%	BBB+	10/30/03
Northern States Power Co. of Wisconsin	9.7	2.1%	12.0	0.6%	A	various to 12
IES Utilities	9.3	2.0%	15.8	0.8%	A-	05/31/03
Wisconsin Gas Company	9.1	2.0%	22.0	1.2%	A	03/31/03
Subtotal of top ten customers	$302.7	65.6%	722.7	38.2%		
Total of all customers	**$461.4**	100.0%	**1,891.4**	100.0%		

Note: * indicates rating at parent company level

Financials

	1997	1998	1999	2000	2001P	2002P	2003P	2004P	2005P
Revenue	507.6	489.9	491.3	505.5	494.9	508.5	522.7	535.4	539.3
% growth		*-3.5%*	*0.3%*	*2.9%*	*-2.1%*	*2.7%*	*2.8%*	*2.4%*	*0.7%*
EBITDA	291.0	282.4	251.7	285.2	223.6	255.0	262.9	270.0	272.1
EBITDA Margin	*57.3%*	*57.6%*	*51.2%*	*56.4%*	*45.2%*	*50.1%*	*50.3%*	*50.4%*	*50.5%*
Capex	197.5	157.1	111.5	67.1	89.7	66.1	56.9	49.2	49.6

Current Capital Structure

6.875% Senior Notes due 2005	$100,000,000
6.75% Senior Notes due 2008	150,000,000
7.00% Senior Notes due 2011	250,000,000
Unamortized debt discount	(296,000)
	$499,704,000

Transwestern Pipeline

Transwestern Pipeline Company ("Transwestern") is a wholly-owned subsidiary of Enron Transportation Services Company ("ETS"), which is a majority owned subsidiary of Enron Corp. Transwestern owns and operates an interstate natural gas pipeline system stretching from Texas, Oklahoma and the San Juan Basin to the California border. Transwestern is a major natural gas transporter to the California border and Mid-Continent markets and aggressively markets off the east end of its system to Texas intrastate and midwest markets.

Transwestern's system consists of approximately 2,700 miles of natural gas pipeline with combined east-west delivery capability of 1.7 Bcf/day. On the west end of the system, Transwestern delivers gas to Southern California Gas Company, Pacific Gas & Electric Company [do they still do this, I know at one point they were cash collateralizing the transactions] and Mojave Pipeline Company at the California border and to Southwest Gas and Citizens Utilities in Arizona. Transwestern supply laterals in the Southwest provide market access to most major production areas. The San Juan Basin lateral in New Mexico has a capacity of 850 MMcf/day. Laterals in Texas and New Mexico access Permian and Anadarko Basin supplies. In May 2000, Transwestern completed an expansion which incereased delivery capability into California by 140 mmcf/d. Transwestern is pursuing additional expansions to its pipeline of approximately 50 mmcf/d and 150 mmcf/d with expected completions in 2001 and 2002 respectively.

Transwestern and its customers agreed to contract rates through 2006 and agreed that Transwestern would not be required to file a new rate case for rates to be effective prior to November 1, 2006. Transwestern's current firm capacity for both west and east flow is fully subscribed under a combination of short and long-term contracts. Relatively small increments of operational capacity become available from time to time and are generally sold on a daily or short-term basis. Approximately 85% of Transwestern's revenues are from firm capacity charges, and the remaining 15% are from firm commodity transportation contracts.

Total volumes transported (Bbtu/d)

2000	1999	1998
1,657	1,462	1,608

Tariffs and Regulated Rates of Return

Year End 2000 Rate Base	465
Regulated Capital Structure	41.57% debt
	58.43% equity
ROIC	10.25%
ROE	11.50%

Global Syndicated Finance - Confidential Date: 09/17/02

Transwestern Pipeline Company Top 10 Customers
(In $MM for the months October 2000 through September 2001)

Customer	Revenues	% total	Volumes	% total	Ratings	Contract maturity
Southern California Gas Co.	$56.3	31.2%	176.8	19.1%	AA-	10/31/05
Texaco Natural Gas	16.2	8.9%	34.4	3.7%	NR*	various to 07
PG&E Energy Trading – Gas Corp.	16.0	8.8%	41.1	4.4%	BBB+*	various to 02
Sempra Energy Trading Corp.	14.6	8.1%	59.6	6.4%	A*	various to 05
BP Energy Company	10.9	6.0%	68.5	7.4%	AA+*	various to 08
Duke Energy Trading and Marketing	7.9	4.4%	46.1	5.0%	A-	various to 07
El Paso Energy Marketing Company	7.3	4.0%	30.8	3.3%	BBB+*	various to 07
Burlington Resources Trading	5.2	2.9%	40.7	4.4%	A-*	various to 06
Agave Energy Co.	4.6	2.6%	42.7	4.6%	NR	various to 03
U S Gas Transportation	4.4	2.4%	59.2	6.4%	NR	03/31/03
Subtotal of top ten customers	$143.3	79.4%	599.8	64.8%		
Total of all customers	$180.6	100.0%	926.3	100.0%		

Note: * indicates rating at parent company level

Financials

	1997	1998	1999	2000	2001P	2002P	2003P	2004P	2005P
Revenue	147.6	167.6	155.7	176.8	192.0	207.9	225.2	244.2	264.9
% growth		*13.6%*	*(7.1%)*	*13.6%*	*8.6%*	*8.3%*	*8.3%*	*8.4%*	*8.5%*
EBITDA	106.4	123.0	106.6	126.0	132.6	143.1	158.0	174.5	192.6
EBITDA Margin	*72.1%*	*73.4%*	*68.5%*	*71.3%*	*69.1%*	*68.8%*	*70.2%*	*71.5%*	*72.7%*
Capex	30.0	18.7	31.3	29.5	67.8	54.2	43.3	34.6	34.6

Pipeline Risks and Mitigating Factors:

Shipper credit risk.
Mitigant: All of Transwestern and Northern Natural Gas Company's customers are investment grade or equivalent rating based on Northern and Transwestern's internal controls. If Northern or Transwestern have shippers that are not considered creditworthy based on internal controls, the shippers are required to post a form of collateral (guarantee by creditworthy parent, L/C, cash) in order to ship on the pipeline and have the tenor of their shipping contracts reduced to review every 90 days. In addition, most of Northern's shippers are LDC's which are State regulated entities that are allowed to recover the costs of shipping from customers based on a revenue requirements model.

Transwestern and Northern maintain strict internal credit controls with the shippers co-ordinated by a Vice President in charge of credit risk management. All shippers are required to provide annual audited financials, and are reviewed for credit status annually

PG&E has historically accounted for approximately $11.7 MM per annum of contract revenues for Transwestern. The current base yields on the contract are approximately $5.8 MM. Due to credit concerns, PG&E prepays its capacity charges on the 25th of the month for shipments on the month following. If the prepayment is not made, PG&E will lose its contracted capacity. PG&E is currently releasing its capacity on the Transwestern system and collecting the additional margin between its shipping tolls and the tolls it can charge to third parties. If PG&E were not to make its prepayment, Transwestern management is confident that it will be able to sell that capacity to the same shippers that are purchasing capacity from PG&E today.

Decontracting risk.
Mitigant: The majority of the pipeline's shipping commitments expire outside the term of the proposed facility (see attached schedule). There is no shipping contract up for renewal on the Northern system in the 2001 and 2002 calendar year and no contracts up for renewal on the Transwestern system before 2006.

Regulatory risk.
Mitigant: Northern's shipping tarrifs and allowed rates of return are in effect until October 31, 2003 – outside the tenor of this facility. Transwestern's shipping tarrifs and allowed rates of return are in effect until November 1, 2006 – outside the tenor of this facility.

Parent Company Business:

ENRON CORP.
Enron is the leading Risk Merchant. Traditionally considered a natural gas pipeline company, Enron's core business is now the management of price risk in fast-growing and deregulating commodity markets. The Risk Merchant franchise accounts for 75% of operating income, and is growing at a 30%-40% annual rate. Enron grows by expanding this business model into new geographies and commodities. Market shares: No. 1 in relatively mature $80 billion U.S. natural gas market; No. 1 in $235 billion U.S. electricity market, opened in 1996 and rapidly growing. Enron also has first mover advantage in the $270 billion European market, opened in February 1999, where it is already profitable and has seen volumes grow ten-fold. Enron expects to solidify its position by using the Internet; EnronOnline already drives over half of total commodity volumes. Also, Enron expects to successfully develop the bandwidth commodity market, where it already has first mover advantage.

Enron's operations are classified into the following business segments:

- *Wholesale Energy Operations and Services* engages primarily in the trade and marketing of natural gas, electricity, and other energy sources and risk management products in North America and Europe, as well as energy asset investments worldwide.

- *Transportation and Distribution* operations engage in the transmission of natural gas across the Company's nine major pipelines and the generation and distribution of electricity.

- *Retail Energy Services* engages in the sale of natural gas and electricity directly to end-use customers, particularly in the commercial and industrial sectors, including the outsourcing of energy-related activities.

- *Broadband Services* was recently developed to establish a communications bandwidth trading market.

WHOLESALE ENERGY OPERATIONS and SERVICES:
Enron's wholesale business (Enron Wholesale) includes its wholesale energy businesses around the world. Enron Wholesale operates in developed and deregulated markets such as North America and Europe, as well as developing or newly deregulating markets including South America, India and Japan.

Enron builds its wholesale businesses through the creation of networks involving asset ownership, contractual access to third-party assets and market-making activities. Each market in which Enron Wholesale operates utilizes these components in a slightly different manner and is at a different stage of development. This network strategy has enabled Enron Wholesale to establish a leading position in its markets. Enron Wholesale's activities are categorized into two business lines: (a) Commodity Sales and Services and (b) Assets and Investments. Activities may be integrated into a bundled product offering for Enron's customers.

Enron Wholesale manages its portfolio of contracts and assets in order to maximize value, minimize the associated risks and provide overall liquidity. In doing so, Enron Wholesale uses portfolio and risk management disciplines, including offsetting or hedging transactions, to manage exposures to market price movements (commodities, interest rates, foreign currencies and equities). Additionally, Enron Wholesale manages its liquidity and exposure to third-party credit risk through monetization of its contract portfolio or third-party insurance contracts. Enron Wholesale also sells interests in certain investments and other assets to improve liquidity and overall return, the timing of which is dependent on market conditions and management's expectations of the investments' value.

Commodity Sales and Services. Enron Wholesale provides reliable commodity delivery and predictable pricing to its customers through forward and other contracts. This market-making activity includes the purchase, sale, marketing and delivery of natural gas, electricity, liquids and other commodities, as well as the management of Enron Wholesale's own portfolio of contracts. Enron Wholesale's market-making activity is facilitated through a network of capabilities including asset ownership. Accordingly, certain assets involved in the delivery of these services are included in this business (such as intrastate natural gas pipelines, gas storage facilities and certain power plants).

TRANSPORTATION AND DISTRIBUTION:
Transportation and Distribution consists of Enron's four major pipelines as well as Portland General, which will be sold to Sierra Pacific in the first half of 2001. Enron's four major pipelines are: Northern Natural Gas, Transwestern Pipeline, Enron's 50% interest in Florida Gas Transmission, and its 12.4% interest in Northern Border Pipeline Company and EOTT Energy Partners, L.P.. The Northern pipeline is the longest of the four, running from Texas to the Canadian border; Transwestern extends from Texas to California and is one of only three major US pipelines serving the growing California market; Florida Gas Transmission extends from Texas to Florida and is the only interstate pipeline currently serving Florida; and Northern Border Pipeline extends from the Western Canadian Basin through Montana, the Dakotas, Minnesota, Iowa and into Chicago. Combined, the four interstate pipelines access virtually every major supply basin in North America, directly serve customers in 21 states, and collectively transport 15% of the gas volume in the US.

Given its strong market position, Enron's pipeline business continues to provide a stable source of cashflow. Revenues are derived largely from fixed fee demand charges (nearly 90%) in long-term contracts. Indeed, with increasing demand for natural gas, Enron has embarked on a significant expansion program of its pipeline network, with virtually all of the additional miles backed by firm, long-term contracts. However, although the pipeline business continues to be solidly profitable, it has shrunk in weighting over the past several years with the growth of the wholesale energy and trading business. Contributions from this segment are expected to continue to shrink on a relative basis, particularly given the pending sale of Portland General and the growth of non-regulated businesses.

Northern Natural Gas Company. See above

Transwestern Pipeline Company. See above

Florida Gas Transmission Company. An Enron subsidiary owns a 50% interest in Florida Gas by virtue of its 50% interest in Citrus Corp., which owns all of the capital stock of Florida Gas. Another Enron subsidiary operates the Florida Gas pipeline.

Florida Gas is an interstate pipeline company that transports natural gas for third parties. Its approximately 4,950-mile dual pipeline system extends from South Texas to a point near Miami, Florida. Florida Gas provides a high degree of gas supply flexibility for its customers because of its proximity to the Gulf of Mexico producing region and its interconnections with other interstate pipeline systems which provide access to virtually every major natural gas producing region in the United States. Florida Gas serves a mix of customers anchored by electric utility generators.

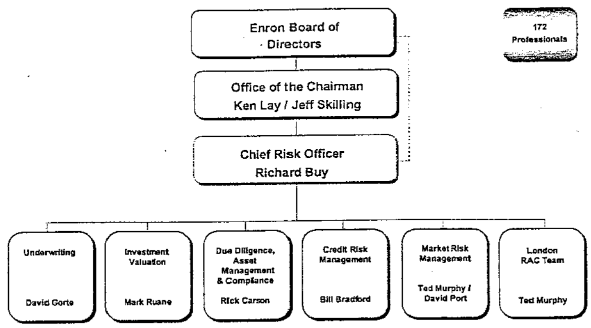
Florida Gas has periodically expanded its system capacity to keep pace with the growing demand for natural gas in Florida. In December 1998, Florida Gas filed an application with the FERC to expand its pipeline capacity to meet Florida's growing electric generation load and local distribution company and industrial demand. The proposed 272 billion British thermal units ("BBtu") per day Phase IV expansion is backed by 20-year firm transportation contracts and, subject to regulatory approvals, is expected to be in service in 2001, introducing Florida Gas to the southwest Florida market. Florida Gas' current firm average delivery capacity into Florida is 1,455 BBtu per day. Florida Gas also owns an interest in facilities that link its system to the Mobile Bay producing area. Florida Gas' customers have reserved over 99% of the existing capacity on the Florida Gas system pursuant to firm, long-term transportation service agreements.

Florida Gas is the only interstate natural gas pipeline serving peninsular Florida. Florida Gas faces competition from residual fuel oil in the Florida market. A primary advantage of the straight fixed variable rate design (a FERC mandated rate design to allow pipelines to recover substantially all fixed costs, a return on equity and income taxes in the capacity reservation component of their rates) is that Florida Gas will recover substantially all of its fixed costs regardless of levels of usage by its customers.

Northern Border Partners, L.P. Northern Border Partners, L.P., a Delaware limited partnership, owns 70% of Northern Border Pipeline Company, a Texas general partnership ("Northern Border"). An Enron subsidiary holds a 12.4% interest in the limited partnership and serves as operator of the pipeline. Northern Border owns an approximately 1,214-mile interstate pipeline system that transports natural gas from the Montana-Saskatchewan border near Port of Morgan, Montana to interconnecting pipelines and local distribution systems in the States of North Dakota, South Dakota, Minnesota, Iowa and Illinois. Northern Border has pipeline access to natural gas reserves in the provinces of Alberta, British Columbia and Saskatchewan, as well as the Williston Basin in the United States. The pipeline system also has access to production of synthetic gas from the Dakota Gasification Plant in North Dakota. Interconnecting pipeline facilities provide Northern Border shippers access to markets in the Midwest, as well as other markets throughout the United States by transportation, displacement and exchange agreements. Therefore, Northern Border is strategically situated to transport significant quantities of natural gas to major gas consuming markets. Based upon existing contracts and capacity, 100% of Northern Border's firm capacity (approximately 2.4 Bcf of natural gas per day) is contractually committed through October 31, 2001. Northern Border competes with two other interstate pipeline systems that transport gas from Canada to the Midwest.

Enron Risk Assessment & Controls:

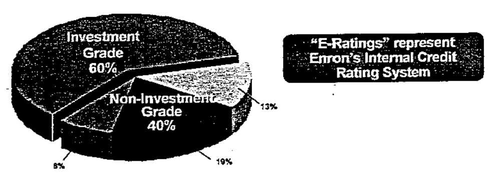
Enron has a specific business unit for monitoring the corporation's risk management activities. Specifically, the Risk Assessment and Controls group (RACs) is responsible for capturing and understanding the Company's risks, optimizing capital allocation, and measuring performance versus expectations. Rick Buy, Enron's Chief Risk Officer, heads RACs. The group includes 172 professionals and has a budget of over $35 million.



RACs must evaluate any request for capital expenditures, or risk-adjusted capital. Any non-conforming requests must be approved by either the ENE office of the Chairman if less than $25 million or by the ENE Board of Directors if $25 million or greater. Conforming requests greater than $75 million must also be approved by the Board.

For the trading portfolio, RACs is responsible for monitoring and understanding three risk categories: credit risk, market risk, and operational risk. RACs must first approve any counterparty and give an E-Score, Enron's equivalent of a risk rating, to that counterparty. RACs reviews contractual arrangements to ensure that credit risk is properly priced and that the transaction includes proper contractual mitigants such as margin requirements and rights of set-off. Finally, RACs uses the Enron systems and controls to monitor credit, market, and operational risk. As deemed appropriate through the monitoring process, RACs will seek to reduce risk through credit enhancements or to syndicate its credit risk (example – CLOs). The advent of Enron OnLine created new challenges for RACs. Challenges that ultimately resulted in superior credit risk tracking. Prior to trading on-line, all counterparties must first be approved by RACs and have exposure limits established. The Enron OnLine system tracks counterparty exposure and calculates the exposure related to new transactions prior to allowing the new transaction to be executed. If the counterparty gets within 20% of its limit, an alarm notifies the Enron trader, who will call the counterparty to notify them of the restricted availability and encourage them to either unwind some trades or post collateral. If a counterparty is at its limit, the trade will not be allowed.

E-Ratings(*)



E-Rating		S&P Rating	Moody's Rating
1-5	Investment Grade	AAA to BBB-	Aaa to Baa3
6-8	Non-Investment Grade	BB+ to BB-	Ba1 to Ba3
9-10		B+ to B-	B1 to B3
11-12		CCC to D	Caa to Ca

(*) as of December 31, 2000

Market Risk: Enron uses industry standard tools for controlling market risk. They set and monitor Value-at-Risk, aggregate risk, return on risk, and limits. Enron's VaR methodology uses a 95% confidence over a one-day time horizon. For 2000, Enron's average VaR increased to $50 million as a result of the increase in its trading book due to Enron OnLine and gas and power volatility. In addition to VaR, Enron monitors its RAROC and uses Stress Testing on its trading books individually and in the aggregate. In addition to these controls, Enron is close to implementing an additional test utilizing extreme market theory. These tests are intended to test extreme market events even more effectively than traditional stress testing.

To insure that operational problems don't result in allowing risks to grow unchecked, Enron utilizes a milestone tracking system that monitors when certain activities are to be accomplished. If something has not been completed, managers are automatically notified by e-mail. If the situation has not been fixed, e-mail alerts go to successively higher levels of management until the operational problem is resolved.

Enron Management:

Kenneth L. Lay (58) - Chairman of the Board and Chief Executive Officer, Enron Corp., since February 1986. ***(Stepped down as CEO effective February 12, 2001)***

Jeffrey K. Skilling (47) - President and Chief Operating Officer, Enron Corp., since January 1997. Chief Executive Officer and Managing Director of Enron Capital & Trade Resources Corp. ("ECT") from June 1995 to December 1996. From August 1990 to June 1995, Mr. Skilling served ECT in a variety of executive managerial positions. ***(Named CEO effective February 12, 2001)***

Mark A. Frevert (44) - President and Chief Executive Officer of ECT Europe and Enron Europe Ltd. since March 1997. From 1993 to March 1997, Mr. Frevert served ECT in a variety of executive managerial positions.

Stanley C. Horton (49) - Chairman and Chief Executive Officer, Enron Gas Pipeline Group, since January 1997. Co-Chairman and Chief Executive Officer of Enron Operations Corp. from February 1996 to January 1997. President and Chief Operating Officer of Enron Operations Corp. from June 1993 to February 1996. President of Northern Natural Gas Company from June 1991 to June 1993. President of Florida Gas Transmission Company from 1988 to May 1991.

Kenneth D. Rice (40) - Chairman and Chief Executive Officer of ECT - North America since March 1997. From 1993 to March 1997, Mr. Rice served ECT in a variety of executive managerial positions.

Joseph W. Sutton (51) - Chief Executive Officer, Enron International Inc., since May 1998. President, Enron International Inc., since January 1996. President and Chief Operating Officer, Enron Development Corp., from May 1995 to January 1996. Vice President, Enron Development Corp., from 1992 to 1995.

Jeff McMahon (40) - Senior Vice President and Chief Financial Officer since October 2001

Northern Natural Gas and Transwestern Management:

Stanley Horton – CEO
Rod Hayslett – CFO and Treasurer

Global Syndicated Finance - Confidential *Date:09/17/02*

Enron Credit Statistics:

Enron Corp. ($MM)	FYE 1997	FYE 1998	FYE 1999	FYE 2000	LTM 9/30/01
Revenues	$20,273	$31,260	$40,112	$100,789	$180,493
EBITDA	1,290	2,205	2,113	2,808	4,608
Senior Debt	6,254	7,357	8,152	10,229	
Total Debt	6,254	7,357	8,152	10,229	
Book Equity	5,618	7,048	9,570	12,374	
Interest Expense	401	550	656	838	851
Capex	1,392	1,905	2,363	2381	
EBITDA/Cash Interest	3.22x	4.01x	3.22x	3.35x	5.41x
Total Debt/Book Cap	52.70%	51.10%	46.00%	45.26%	
Senior Debt/EBITDA	4.85x	3.34x	3.86x	3.64x	
Total Debt/EBITDA	4.85x	3.34x	3.86x	3.64x	

Key Deal Terms:

Key Deal Terms	Proposed Deal
Amount	$1.0-$1.2 billion
Facilities	$550-$650MM at Transwestern $450-$550MM at NNG
Maturity	364-day
Commitment Amount	$500-$600 million
Hold Amount	$150 million
Drawn Cost	[ ] bps
Ave Upfront Fees to Market	[ ] bps
Funded ?	Not anticipated
Guaranteed ?	Yes
Secured ?	Yes
Administrative Agent	JPM / Citicorp

Syndication Strategy:

Expect JPM and Citi to hold [$150] MM and approach other top relationship banks for $100MM and $50MM commitments. Approach borrowing base lenders as potential new lenders. We would have unlimited market flex to fill-out the deal.

Global Syndicated Finance - Confidential **Date:09/17/02**

Cross Sell Opportunities and Strategy:

JPM continues to be a first tier bank to Enron (Premium Client) and is one of its top two agents (Citibank being our principal competition). For fiscal year 2000, 1999, 1998 respectively, JPM earned approximately $27 million, $25 million, $20 million in revenues from the Enron relationship.

Enron Corp. Relationship Profitability

	Full Year 2000 - Revenue	Full Year 2000 - SVA	YTD August 2001 - Revenue	YTD August 2001 - SVA
Corporate Advisory	500,317	87,649	2,204,343	400,303
Equity Underwriting	900	209	1,959,276	441,087
Debt Underwriting	2,173,601	498,689	231,654	30,424
Loan Syndications	3,528,260	876,335	5,654,496	1,396,710
Derivatives	15,644,158	2,187,908	2,151,858	304,623
Credit Related	4,474,519	967,146	2,129,982	148,765
Annuity	1,134,496	294,584	1,559,154	458,429
Total	27,456,251	4,912,520	15,890,763	3,180,341

Specific transactions over the prior 12 months include:

Lead manager – FGT 144a Bonds	$1.2 million
Co-manager – IPO for The New Power Company:	???
Project Tammy Syndication:	$1.5 million
Co-manager on convertible bond offering:	$2 million
Project Slapshot – Structured Financing:	$5.075 million
Co-lead arranger –Corp. CP facility:	$150 thousand
Extension – JEDI II	$250 thousand

Current mandates include:

Sell Side M&A mandate Azurix North America/Mexico/Misc.:	$3 – 5 million (closing stages)
Azurix Europe Ltd. Syndication/Ratings Advisor:	$1 million

Strong Leads:

Convertible Bond back by GAIL ADRs	$1.5 million
Sell side mandate for Mariner Oil & Gas	???

FOR FURTHER INFORMATION CONTACT: Walter R. Cochran, Manager, Airspace Branch, Air Traffic Division, Federal Aviation Administration, P.O. Box 20636, Atlanta, Georgia 30320; telephone (404) 305–5586.

SUPPLEMENTARY INFORMATION:

Comments Invited

Interested parties are invited to participate in this proposed rulemaking by submitting such written data, views or arguments as they may desire. Comments that provide the factual basis supporting the views and suggestions presented are particularly helpful in developing reasoned regulatory decisions on the proposal. Comments are specifically invited on the overall regulatory, aeronautical, economic, environmental, and energy-related aspects of the proposal. Communications should identify the airspace docket number and be submitted in triplicate to the address listed above. Comments wishing the FAA to acknowledge receipt of their comments on this action must submit with those comments a self-addressed, stamped postcard on which the following statement is made: "Comments to Airspace Docket No. 02–ASO–9." The postcard will be date/time stamped and returned to the commenter. All communications received before the specified closing date for comments will be considered before taking action on the proposed rule. The proposal contained in this action may be changed in light of the comments received. All comments submitted will be available for examination in the Office of the Regional Counsel for Southern Region, Room 550, 1701 Columbia Avenue, College Park, Georgia 30337, both before and after the closing date for comments. A report summarizing each substantive public contact with FAA personnel concerned with this rulemaking will be filed in the docket.

Availability of NPRMs

Any person may obtain a copy of this Notice of Proposed Rulemaking (NPRM) by submitting a request to the Federal Aviation Administration, Manager, Airspace Branch, ASO–520, Air Traffic Division, P.O. Box 20636, Atlanta, Georgia 30320. Communications must identify the docket number of this NPRM. Persons interested in being placed on a mailing list for future NPRMs should also request a copy of Advisory Circular No. 11–2A which describes the application procedure.

The Proposal

The FAA is considering an amendment to part 71 of the Federal Aviation Regulations (14 CFR part 71) to amend Class E airspace at Prestonburg, KY. A RNAV (GPS), RWY 3, a RNAV (GPS) RWY 21, and a VOR/DME–A SIAP has been developed for Big Sandy Regional Airport, KY. Controlled airspace extending upward from 700 feet AGL is needed to accommodate the SIAPs. Class E airspace designations for airspace areas extending upward from 700 feet or more above the surface of the earth are published in Paragraph 6005 of FAA Order 7400.9J, dated August 31, 2001, and effective September 16, 2001, which is incorporated by reference in 14 CFR 71.1. The Class E airspace designation listed in this document would be published subsequently in the Order.

The FAA has determined that this proposed regulation only involves an established body of technical regulations for which frequent and routine amendments are necessary to keep them operationally current. It, therefore, (1) is not a "significant regulatory action" under Executive Order 12866; (2) is not a "significant rule" under DOT Regulatory Policies and Procedures (44 FR 11034; February 26, 1979); and (3) does not warrant preparation of a Regulatory Evaluation as the anticipated impact is so minimal. Since this is a routine matter that will only affect air traffic procedures and air navigation, it is certified that this rule, when promulgated, will not have a significant economic impact on a substantial number of small entities under the criteria of the Regulatory Flexibility Act.

List of Subjects in 14 CFR Part 71

Airspace, Incorporation by reference, Navigation (air).

The Proposed Amendment

In consideration of the foregoing, the Federal Aviation Administration proposes to amend 14 CFR Part 71 as follows:

PART 71—DESIGNATION OF CLASS A, CLASS B, CLASS C, CLASS D, AND CLASS E AIRSPACE AREAS; AIRWAYS; ROUTES; AND REPORTING POINTS

1. The authority citation for part 71 continues to read as follows:

Authority: 49 U.S.C. 106(g); 40103, 40113, 40120; E.O. 10854, 24 FR 9565, 3 CFR, 1959–1963 Comp., p. 389.

§ 71.1 [Amended]

2. The incorporation by reference in 14 CFR 71.1 of Federal Aviation Administration Order 7400.9J, Airspace Designations and Reporting Points, dated August 31, 2001, and effective September 16, 2001, is amended as follows:

Paragraph 6005 Class E Airspace Areas Extending Upward from 700 feet or More Above the Surface of the Earth

* * * * *

ASO KY E5 Prestonburg, KY [REVISED]

Prestonburg, Big Sandy Regional Airport, KY

(Lat. 37°45′04″N, long. 82°38′12″W)

That airspace extending upward from 700 feet or more above the surface within a 6.5-mile radius of the Big Sandy Regional Airport.

* * * * *

Issued in College Park, Georgia, on July 24, 2002.

Walter R. Cochran,

Acting Manager, Air Traffic Division, Southern Region.

[FR Doc. 02–19555 Filed 8–6–02; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 101, 201, and 352

[Docket No. RM02–14–000]

Regulation of Cash Management Practices

August 1, 2002.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: In order to protect the customers of jurisdictional companies, the Federal Energy Regulatory Commission is proposing to establish limits on the amount of funds that can be swept from a regulated subsidiary to a non-regulated parent under so-called "cash management" programs, as well as certain other requirements.

DATES: Comments are due 15 days after publication in the **Federal Register**.

ADDRESS: File written comments with the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington DC, 20426. Comments should reference Docket No. RM02–14–000. Comments may be filed electronically or by paper (an original and 14 copies with an accompanying computer diskette in the prescribed format requested).

FOR FURTHER INFORMATION CONTACT:
Mark Klose (Technical Information), Office of the Executive Director, Division of Regulatory Accounting Policy, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 219–2595.
Mary Lauermann (Technical Information), Office of the Executive Director, Division of Regulatory Audits, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 208–0087.
Peter Roidakis (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202)208–1213.

SUPPLEMENTARY INFORMATION:

I. Introduction

1. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) proposes to amend its Uniform Systems of Accounts [1] for public utilities,[2] natural gas companies [3] and oil pipeline companies [4] by establishing the documentation necessary "to furnish readily full information" [5] concerning the management of funds from a FERC-regulated subsidiary by a non-FERC-regulated parent.[6] Specifically, the Commission is requiring that all such arrangements be in writing. Such arrangements must specify the duties and responsibilities of cash management participants and administrators, the methods of calculating interest and for allocating interest income and expenses, and the restrictions on deposits or borrowings by money pool members.

2. Under the proposed rule, such cash management or money pool agreements must provide documentation for all deposits into, borrowings from, interest income from, and interest expenses to such money pools. Such documentation shall include evidences of: (1) Each deposit with a money pool, including the date of the deposit, the amount of the deposit, the maturity date, if any, of the deposit, and the interest earning rate on the deposit; (2) each borrowing from a money pool, including the date of the borrowing, the amount of the borrowing, the maturity date, if any, of the borrowing and the interest rate on the borrowing; (3) the security provided by the money pool for repayment of deposits into the money pool and the security required by the money pool in support of borrowings from the money pool; and (4) daily balances of deposits with and borrowings from the money pool for each individual deposit or borrowing. Cash deposits and borrowings may not be netted.

3. Finally, the Commission is proposing that as a condition for participating in a cash management or money pool arrangement, the FERC-regulated entity must maintain a minimum proprietary capital balance (stockholder's equity) of 30 percent, and the FERC-regulated entity and its parent must maintain investment grade credit ratings. If either of these conditions is not met, the FERC-regulated entity may not participate in the cash management or money pool arrangement.

4. The proposed rule is in the public interest because it will permit FERC-regulated entities to benefit from properly structured cash management programs, while protecting customer interests.

II. Background

Cash Management Programs Generally

5. The overall objective of a cash management program is to enhance owner value. Cash management arrangements can provide participants with greater financing flexibility and a lower cost of borrowing than would otherwise be available to small entities. These arrangements can help smaller affiliates within the group receive the same favorable rates as larger entities.

6. There are several types of cash management programs. Some concentrate and transfer funds from multiple accounts into a single bank account in the parent company's name. Another type is known as "cash pooling" or "money pooling." This system uses a single summary account with interest earned or charged on the net cash balance position. There is no movement of funds between accounts of the entities participating in the pool. All accounts must be in the same bank, but not at the same branch. A third type, known as "zero balance accounts," empty or fill the balances in affiliated companies' accounts at a bank into or out of a parent's account each day.

7. In a typical zero balance program, excess funds are swept to a corporate concentration account every night from the regulated company's zero balance accounts, and an account receivable from the parent is established at the regulated company while an account payable is established at the parent company to record the transfer of funds. As part of the cash management program, the parent company provides the funds for payment of payroll and other expenditures of its subsidiaries from the funds that have been swept to the parent. The parent invests unspent funds in overnight investments so that the money of all the subsidiaries will be working for the company rather than being idle.

8. Cash management programs are not without risk, however. Problems can arise over the respective rights to the concentration or pooled account when the parent company or its subsidiaries file for bankruptcy. Courts have ruled that funds swept into a parent company's concentration account become the property of the parent, and the subsidiary loses all interest in those funds.[7]

9. There is thus a potential for degradation of the financial solvency of regulated entities if non-regulated parent companies declare bankruptcy and default on the accounts payable, advances or borrowings owed to their regulated subsidiaries.

FERC Regulated Entities' Cash Management Programs

10. In the fall of 2001, the Commission's Chief Accountant began a review of transactions between unregulated parent companies and their jurisdictional subsidiaries. Specifically, the balances in the cash account and accounts related to associated companies, reported in the FERC Forms 1, 2, and 6, were reviewed for the years 1997 through 2001. This review revealed that many companies had significant balances in Account 146—

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[1] Section 301(a) of the Federal Power Act (FPA), 16 U.S.C. 825(a), section 8 of the Natural Gas Act (NGA), 15 U.S.C. 717g, and section 20 of the Interstate Commerce Act (ICA), 49 App. U.S.C. 20 (1998), authorize the Commission to prescribe rules and regulations concerning accounts, records and memoranda as necessary or appropriate for the purposes of administering the FPA, NGA and the ICA. The Commission may prescribe a system of accounts for jurisdictional companies and, after notice and opportunity for hearing, may determine the accounts in which particular outlays and receipts will be entered, charged or credited.

[2] Part 101 Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. 18 CFR part 101 (2002).

[3] Part 201 Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. 18 CFR part 201 (2002).

[4] Part 352 Uniform System of Accounts Prescribed for Oil Pipeline Companies Subject to the Provisions of the Interstate Commerce Act. 18 CFR part 352 (2002).

[5] *See* General Instructions—Records under Parts 101, 201, and 352 of the Commission's Uniform System of Accounts for public utilities, licensees, natural gas companies, and oil pipeline companies.

[6] The proposed regulations would apply to all public utilities subject to the Uniform System of Accounts, all natural gas companies subject to the Uniform System of Accounts, and all oil pipeline carriers subject to the Uniform System of Accounts.

[7] *See, e.g.*, In the Matter of Southmark Corporation, 49 F.3d 1111 (5th Cir. 1995), and *In re* Amdura Corporation, 75 F.3d 1447 (10th Cir. 1996).

Accounts Receivable from Associated Companies, and Account 13—Receivables from Affiliated Companies, and that the balances in these accounts were significantly increasing over the period under review.

11. As a result of the use of cash management programs and the increased balances in Account 146 identified by this initial review, the Chief Accountant began an audit in January 2002, to determine compliance with the Commission's accounting and reporting requirements for the years 2000 through 2001.

12. In March 2002, the Commission initiated a non-public investigation by the Chief Accountant, Office of the Executive Director, and the Market Oversight and Enforcement section, Office of the General Counsel, regarding financial data related to transactions, activities and accounting practices that may have impaired the financial condition of entities subject to the Commission's jurisdiction to the benefit of corporate parents or other affiliates or associated entities of jurisdictional companies.

13. The investigators reviewed transactions affecting Account 146—Accounts Receivable from Associated Companies for gas and electric companies, and Account 13—Receivables from Affiliated Companies for oil companies. Based on FERC Forms 1, 2 and 6 data from 2001, balances in Accounts 146 and 13 totaled approximately $16 billion ($8.2 billion in public utility accounts, $2 billion in natural gas company accounts, and $5.7 billion in oil and product pipeline accounts). The preliminary results of the audit/investigation also revealed severe record-keeping deficiencies:

- Cash management agreements, generally and across the electric, gas and oil industries, have not been formalized in writing to stipulate the terms of the programs and the interest associated with the loans of the subsidiaries' cash.
- Interest may or may not have been paid to subsidiary companies by the parents.
- Budgets are not developed at the subsidiary level for capital expenditures and operations and maintenance expenses.
- Inter-company billings between parents and subsidiaries may have occurred at preferential rates not given to non-affiliated customers.

III. Legal Authority and Proposed Regulations

14. The Commission is proposing to require clearly defined roles and responsibilities of all parties regarding transfers of cash, payments of bills, payments of interest, and the limitations to which funds can be taken from FERC-regulated subsidiaries. Cash management agreements must be reviewed and updated periodically to ensure that changes in corporate structure have not made the agreements obsolete.

15. The Natural Gas Act (NGA) with respect to natural gas companies, and the Federal Power Act (FPA) with respect to public utilities, and the Interstate Commerce Act (ICA) with respect to oil pipeline carriers authorize the Commission to prescribe rules and regulations concerning accounts, records and memoranda as necessary or appropriate for the purposes of administering the FPA, NGA, and the ICA.[8] The NGA and the FPA also empower the Commission, with respect to natural gas pipelines and public utilities, to "perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of [the] Act." Section 16 of the NGA, 15 U.S.C. 717*o*, and section 309 of the FPA, 16 U.S.C. 825(h). Under the Interstate Commerce Act (ICA), the Commission may, with respect to oil and product pipelines "prescribe the forms of any and all accounts, records, and memoranda to be kept by carriers * * * as well as of the receipts and expenditures of monies." ICC, Title 49 Appendix section 20 (5), 49 App. U.S.C. 20 (5) (1988). The Commission also has the authority to perform the duties for which it was created "to inquire into and report on the business of persons controlling, controlled by, or under a common control with such carriers * * *." ICA, Title 49 Appendix section 12, 49 App. U.S.C. 12 (1988).

16. The Commission proposes to revise Account 146 in parts 101 and 201, and Account 13 in part 352 to provide instructions and conditions for the maintenance of cash management arrangements. Specifically, the Commission is requiring that all such arrangements be in writing. Such arrangements must specify the duties and responsibilities of cash management participants and the administrator, the methods of calculating interest and for allocating interest income and expenses, and the restrictions on deposits or borrowings by money pool members.

17. Under the proposed rule, such cash management agreements must provide documentation for all deposits into, borrowings from, interest income from, and interest expenses related to such agreements. Such documentation shall include evidence of: (1) Each deposit with a money pool, including the date of the deposit, the amount of the deposit, the maturity date, if any, of the deposit, and the interest earning rate on the deposit; (2) each borrowing from a money pool, including the date of the borrowing, the amount of the borrowing, the maturity date, if any, of the borrowing and the interest rate on the borrowing; (3) the security provided by the money pool for repayment of deposits into the money pool and the security required by the money pool in support of borrowings from the money pool; and (4) daily balances of deposits with and borrowings from the money pool for each individual deposit or borrowing. Cash deposits and borrowings may not be netted.

18. Because of the Commission's concern that such accounts not be used improperly so as to cause serious financial harm to FERC-regulated entities, and ultimately cause harm to the ratepayers, the Commission proposes that as a prerequisite to participating in a cash management arrangement, a FERC-regulated entity shall maintain a minimum proprietary capital balance of 30 percent,[9] and the FERC-regulated entity and its parent must maintain investment grade credit ratings.[10] If either of these conditions is no longer met, the FERC-regulated entity may not participate in the cash management or money pool arrangement.

IV. Information Collection Statement

19. The following collection of information contained in this proposed rule has been submitted to the Office of Management and Budget for emergency review under section 3507(j)(1) of the Paperwork Reduction Act of 1995, 44 U.S.C. 3507(j)(1). Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance quality, utility, and clarity of the information to

[8] *See* n.1, *supra*.

[9] *See* Niagara Mohawk Holdings, Inc. 99 FERC ¶ 61,323 (2002), where the Commission conditionally approved a requirement that a company maintain an equity balance equal to at least 30 percent of capital.

[10] The term "investment grade" was originally used by regulatory bodies to connote obligations eligible for investment by institutions such as banks, insurance companies, and savings and loan associations. Over time, this term became widespread throughout the investment community. Debt issues rated in four highest categories (*e.g.*, Standard & Poor's AAA, AA, A, and BBB rating, or Moody's Investors Service Aaa, Aa, and A and Baa rating are generally recognized as being investment grade. Lower rating categories are generally considered speculative.

be collected, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

Estimated Annual Burden

At present it is unclear how many companies already have written agreements in place and would not be impacted by this rule. But there are a significant number of FERC-regulated entities that could be impacted by this rule because of their membership in consolidated groups and their participation in cash management arrangements. For this reason, the Commission projects the total hours for the following collections of information:

Data collection	Number of respondents	Estimated % that are members of a consolidated group	No. of responses	Total annual hrs.
FERC–Form 1	268	51% or 137 (approx)	137	274
FERC Form 2	133	85% or 113 (approx)	113	226
FERC Form 6	201	98.5% or 198 (approx)	198	396
Totals				896

Total Annual Hours for Collection

(Reporting + Recordkeeping, (if appropriate)) = 896 hours

* This estimate is based on an average of 2 hours per respondent to convert verbal agreements into written agreements.

Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements. It has projected the cost for compliance to be the following: 896 hours ÷ 2,080 × $117,041 = $50,418.

Annualized capital/startup costs	$0
Annualized costs (Operations & Maintenance)	$50,418
Total annualized costs	$50,418

The Office of Management and Budget's (OMB) regulations [11] require OMB to approve certain information collection requirements imposed by agency rule. The Commission is submitting notification of this proposed rule to OMB.

Title: FERC Form 1 Annual Report of Major Electric Utilities, Licensees and Others; FERC Form 2 Annual Report for Major Natural Gas Companies; FERC Form No. 6 Annual Report of Oil Pipeline Companies.

Action: Proposed Collections.

OMB Control No: 1902–0021; 1902–0028; and 1902–0022. [Note: The collections of information contained in this proposed rule are being submitted to OMB under OMB's emergency clearance procedures. These collections of information are also the subject of a separate proceeding in Docket No. RM02–3–000, and to avoid any delay in OMB's review of this proposed rule, the collections of information in this proposed rule will have a temporary designation of FERC–907. When the Commission issues a final rule, the collections of information will revert to their normal identifiers and control numbers.]

Respondents: Business or other for profit.

Frequency of Responses: On occasion.

Necessity of the Information: The Commission proposes to revise its Uniform System of Accounts to establish the documentation necessary to disclose information on the management of funds from a FERC-regulated subsidiary by a non-regulated parent. Specifically, the Commission is requiring that all such cash management arrangements be in writing. Such arrangements must specify the duties and responsibilities of cash management participants and administrators, the methods of calculating the interest and for allocating interest income and expenses, and the restrictions on deposits and/or borrowing of money pool members. The Commission is also proposing that as a condition for participating in cash management arrangements, the FERC-regulated entity must maintain a minimum proprietary capital balance of 30 percent and the FERC-regulated entity and its parent must maintain investment grade ratings.

As a result of the Commission's investigations, it was found that cash management agreements, generally and across the electric, gas and oil industries have not been formalized in writing stipulating both the terms of the programs and the interest associated with the loans of the subsidiaries' cash. In addition, budgets are not developed at the subsidiary level for capital expenditures, operations and maintenance expenses and the interest that may or may not have been paid to subsidiary companies by the parent.

The Commission is concerned that such accounts may be used so as create severe financial risk to FERC-regulated entities, and cause harm to rate payers should the subsidiaries attempt to pass through costs that result from defaults by unregulated parent companies, resulting in higher costs of capital.

Internal Review: The Commission has reviewed the requirements pertaining to the Uniform System of Accounts and to the three financial reports it prescribes and has determined that the proposed revisions are necessary because the Commission needs to establish uniform accounting and reporting requirements for cash management arrangements.

These requirements conform to the Commission's plan for efficient information collection, communication, and management within the electric, natural gas and oil pipeline industries. The Commission has assured itself, by means of internal review, that there is objective support for the burden estimates associated with the information requirements.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, [Attention: Michael Miller, Office of the Chief Information Officer, Phone: (202) 502–8415, fax: (202) 208–2425, e-mail: *michael.miller@ferc.fed.us*]

For submitting comments concerning the collection of information(s) and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Management and Budget, Office of Information and Regulatory Affairs, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone (202) 395–7856, fax: (202) 395–7285.

V. Environmental Analysis

20. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human

[11] 5 CFR 1320.11 (1996).

environment.[12] The Commission excludes certain actions not having a significant effect on the human environment from the requirement to prepare an environmental impact statement.[13] No environmental consideration is raised by the promulgation of a rule that is procedural or does not substantially change the effect of legislation or regulations being amended.[14] The proposed rule updates Parts 101, 201, and 352 of the Commission's regulations, and does not substantially change the effect of the underlying legislation or the regulations being revised or eliminated. Accordingly, no environmental consideration is necessary.

VI. Regulatory Flexibility Act Statement

21. The Regulatory Flexibility Act of 1980 (RFA)[15] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The Commission is not required to make such analyses if a rule would not have such an effect. The Commission concludes that this rule would not have such an impact on small entities. Most filing companies regulated by the Commission do not fall within the RFA's definition of a small entity, and the data required by this rule are already being captured by their accounting systems. However, if the reporting requirements represent an undue burden on small businesses, the entity affected may seek a waiver of the requirements from the Commission.

VII. Comment Procedures

22. The Commission invites interested persons to submit written comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 15 days from publication in the **Federal Register**. Comments must refer to Docket No. RM02–14–000, and may be filed either in electronic or paper format. Those filing electronically do not need to make a paper filing.

23. Documents filed electronically via the Internet can be prepared in a variety of formats, including WordPerfect, MS Word, Portable Document Format, Real Text Format, or ASCII format, as listed on the Commission's web site at *http://ferc.gov*, under the e-Filing link. The e-Filing link provides instructions for how to Login and complete an electronic filing. First time users will have to establish a user name and password. The Commission will send an automatic acknowledgment to the sender's E-Mail address upon receipt of comments. User assistance for electronic filing is available at 202–208–0258 or by E-Mail to *efiling@ferc.gov*. Comments should not be submitted to the E-Mail address.

24. For paper filings, the original and 14 copies of such comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington DC 20426.

25. All comments will be placed in the Commission's public files and will be available for inspection in the Commission's Public Reference Room at 888 First Street, NE., Washington DC 20426, during regular business hours. Additionally, all comments may be viewed, printed, or downloaded remotely via the Internet through FERC's Homepage using the FERRIS link.

VIII. Document Availability

26. 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 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

27. 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.

28. 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

18 CFR Part 101

Electric power, Electric utilities, Reporting and recordkeeping requirements, Uniform System of Accounts.

18 CFR Part 201

Natural gas, Reporting and recordkeeping requirements, Uniform System of Accounts.

18 CFR Part 352

Pipelines, Reporting and recordkeeping requirements, Uniform System of Accounts.

By direction of the Commission.

Magalie R. Salas,

Secretary.

In consideration of the foregoing, the Commission proposes to amend parts 101, 201, and 352, Title 18 of the Code of Federal Regulations, as follows:

PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

1. The authority citation for part 101 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352, 7651–7651o.

2. In part 101, Balance Sheet Accounts, account 146 is revised to read as follows:

Balance Sheet Accounts

* * * * *

146 *Accounts receivable from associated companies.*

A. These accounts shall include notes and drafts upon which associated companies are liable, and which mature and are expected to be paid in full not later than one year from the date of issue, together with any interest thereon, and debit balances subject to current settlement in open accounts with associated companies. Items which do not bear a specified due date but which have been carried for more than twelve months and items which are not paid within twelve months from the due date shall be transferred to account 123, Investment in Associated Companies.

B. As a prerequisite for participating in a cash management or money pool arrangement, a utility shall maintain a minimum proprietary capital balance of 30 percent, and a utility and its parent must maintain an investment grade credit rating. If either of these requirements is not met, the utility may not participate in the cash management or money pool arrangement. A utility participating in a cash management or money pool arrangement shall maintain supporting documentation for all deposits into, borrowings from, interest income from, and interest expense to such money pool. The written documentation shall include evidences

[12] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 47897 (Dec. 17, 1987), FERC Stats. & Regs. Prambles 1986–1990 ¶ 30,783 (1987).

[13] 18 CFR 380.4.

[14] 18 CFR 380.4(a)(2)(ii).

[15] 5 U.S.C. 601–612.

of: (1) Each deposit with the money pool, including the date of the deposit, the amount of the deposit, the maturity date, if any, of the deposit, and the interest earning rate on the deposit; (2) each borrowing from a money pool, including the date of the borrowing, the amount of the borrowing, the maturity date, if any, of the borrowing and the interest rate on the borrowing; (3) the security provided by the money pool for repayment deposits into the money pool and the security required by the money pool in support of borrowings from the money pool; and (4) daily balances of deposits with and borrowings from the money pool for each individual deposit or borrowing. Cash deposits and borrowings may not be netted.

C. The utility shall also maintain current and up-to-date copies of the documents authorizing the establishment of the cash management or money pool arrangement that specifies the following: (1) The duties and responsibilities of the money pool, its administrator and the other participants in the money pool; (2) the restrictions on deposits or borrowings by pool members, (3) the method used to determine the interest earning rates and interest borrowing rates by pool members; and (4) the method used to allocate interest income and expenses among the pool members.

Note A: On the balance sheet, accounts receivable from an associated company may be set off against accounts payable to the same company.

Note B: The face amount of notes receivable discounted, sold or transferred without releasing the utility from liability as endorser thereon, shall be credited to a separate subdivision of this account and appropriate disclosure shall be made in financial statements of any contingent liability arising from such transactions.

* * * * *

PART 201—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT

3. The authority citation for part 201 continues to read as follows:

Authority: 15 U.S.C. 717–717w, 3301–3432; 42 U.S.C. 7101–7352, 7651–7651o.

4. In part 201, Balance Sheet Accounts, account 146 is revised to read as follows:

Balance Sheet Accounts

* * * * *

146 *Accounts receivable from associated companies.*

A. These accounts shall include notes and drafts upon which associated companies are liable, and which mature and are expected to be paid in full not later than one year from the date of issue, together with any interest thereon, and debit balances subject to current settlement in open accounts with associated companies. Items which do not bear a specified due date but which have been carried for more than twelve months and items which are not paid within twelve months from the due date shall be transferred to account 123, Investment in Associated Companies.

B. As a prerequisite for participating in a cash management or money pool arrangement, a utility shall maintain a minimum proprietary capital balance of 30 percent and a utility and its parent must maintain an investment grade credit rating. If either of these requirements is not met, the utility may not participate in the cash management or money pool arrangement. A utility participating in a cash management or money pool arrangement shall maintain supporting documentation for all deposits into, borrowings from, interest income from, and interest expense to such money pool. The written documentation shall include evidences of: (1) Each deposit with the money pool, including the date of the deposit, the amount of the deposit, the maturity date, if any, of the deposit, and the interest earning rate on the deposit; (2) each borrowing from a money pool, including the date of the borrowing, the amount of the borrowing, the maturity date, if any, of the borrowing and the interest rate on the borrowing; (3) the security provided by the money pool for repayment deposits into the money pool and the security required by the money pool in support of borrowings from the money pool; and (4) daily balances of deposits with and borrowings from the money pool for each individual deposit or borrowing. Cash deposits and borrowings may not be netted.

C. The utility shall also maintain current and up-to-date copies of the documents authorizing the establishment of the money pool that specifies the following: (1) The duties and responsibilities of the money pool, its administrator and the other participants in the money pool; (2) the restrictions on deposits or borrowings by pool members, (3) the method used to determine the interest earning rates and interest borrowing rates by pool members; and (4) the method used to allocate interest income and expenses among the pool members.

Note A: On the balance sheet, accounts receivable from an associated company may be set off against accounts payable to the same company.

Note B: The face amount of notes receivable discounted, sold or transferred without releasing the utility from liability as endorser thereon, shall be credited to a separate subdivision of this account and appropriate disclosure shall be made in financial statements of any contingent liability arising from such transactions.

* * * * *

PART 352—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR OIL PIPELINE COMPANIES SUBJECT TO THE PROVISIONS OF THE INTERSTATE COMMERCE ACT

5. The authority citation for part 352 continues to read as follows:

Authority: 49 U.S.C. 60502; 49 App. U.S.C. 1–85 (1988).

* * * * *

6. In part 352, Balance Sheet Accounts, account 13 is revised to read as follows:

Balance Sheet Accounts

* * * * *

13 *Receivables from affiliated companies.*

(a) This account shall include amounts receivable due and accrued from affiliated companies subject to settlement within one year from date of the balance sheet. This includes receivables for items such as revenue for services rendered, material furnished, rent, interest and dividends, advances and notes.

(b) As a prerequisite for participating in a cash management or money pool arrangement, a carrier shall maintain a minimum proprietary capital balance of 30 percent, and a carrier and its parent must maintain an investment grade credit rating. If either of these requirements is not met, the carrier may not participate in the cash management or money pool arrangement. A carrier participating in a money pool arrangement shall maintain supporting documentation for all deposits into, borrowings from, interest income from, and interest expense to such money pool. The written documentation shall include evidences of: (1) Each deposit with the money pool, including the date of the deposit, the amount of the deposit, the maturity date, if any, of the deposit, and the interest earning rate on the deposit; (2) each borrowing from a money pool, including the date of the borrowing, the amount of the borrowing, the maturity date, if any, of the borrowing and the interest rate on the borrowing; (3) the security provided by the money pool for repayment deposits into the money pool and the security required by the money pool in support of borrowings from the money pool; and (4) daily balances of deposits with and borrowings from the money pool for each individual deposit or borrowing. Cash deposits and borrowings may not be netted.

(c) The carrier shall also maintain current and up-to-date copies of the documents authorizing the establishment of the money pool that specifies the following: (1) The duties and responsibilities of the money pool, its administrator and the other participants in the money pool; (2) the restrictions on deposits or borrowings by pool members, (3) the method used to determine the interest earning rates and interest borrowing rates by pool members; and (4) the method used to allocate interest income and expenses among the pool members.

[FR Doc. 02–20016 Filed 8–6–02; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF THE TREASURY

Bureau of Alcohol, Tobacco and Firearms

27 CFR Part 9

[Notice No. 951; Re: Notice No. 903]

RIN 1512–AC83

Denial of the California Coast Viticultural Area Petition (2000R–166P)

AGENCY: Bureau of Alcohol, Tobacco and Firearms (ATF), Treasury.

ACTION: Termination of proposed rulemaking; denial of petition.

SUMMARY: The Bureau of Alcohol, Tobacco and Firearms (ATF) announces the denial of the petition requesting establishment of the "California Coast" viticultural area and the termination of the related proposed rulemaking (Notice No. 903 of September 26, 2000, 65 FR 57763). ATF has concluded the petitioned viticultural area fails to meet the regulatory requirements issued under the authority of the Federal Alcohol Administration Act. ATF also announces that a supplemental report, "ATF Response to the California Coast Viticultural Area Petition," detailing the reasons for the petition's denial is available on the ATF website or by U.S. mail as described below.

ADDRESSES: A copy of this notice (Notice No. 951) and a link to the 80-page supplemental report, "ATF Response to the California Coast Viticultural Area Petition," detailing the reasons for the petition's denial, are available on the ATF website at: *http://www.atf.treas.gov/alcohol/rules/index.htm.*

Paper copies of the petition, the proposed regulation, the appropriate maps, the comments received in response to Notice No. 903, this notice (Notice No. 951), and the supplemental report are available for public inspection by appointment in the ATF Reading Room, Rm. 6480, 650 Massachusetts Avenue, NW., Washington, DC 20226; telephone (202) 927–7890.

To obtain paper copies of the supplemental report, the comments received, or any other of the above documents by mail (at 20 cents per page), contact the ATF Librarian at the above address.

FOR FURTHER INFORMATION CONTACT: Nancy Sutton, Specialist, Regulations Division (San Francisco, CA), Bureau of Alcohol, Tobacco and Firearms, 221 Main Street, 11th Floor, San Francisco, CA 94105; telephone (415) 947–5192.

SUPPLEMENTARY INFORMATION:

Background—Viticultural Areas

The Federal Alcohol Administration Act (FAA Act) at 27 U.S.C. 205(e) requires that alcohol beverage labels provide the consumer with adequate information regarding a product's identity and prohibits the use of deceptive information on such labels. The FAA Act also authorizes the Bureau of Alcohol, Tobacco and Firearms (ATF) to issue regulations to carry out its provisions.

Regulations in 27 CFR part 4, Labeling and Advertising of Wine, allow the establishment of definitive viticultural areas. The regulations allow the names of approved viticultural areas to be used as appellations of origin on wine labels and in wine advertisements. Section 4.25a(e)(1) defines an American viticultural area as a delimited grape-growing region distinguishable from surrounding areas by geographical features such as climate, elevation, soil, and topography.

ATF believes that viticultural area designations enable consumers to better identify the origin of the grapes used to produce a wine, provide significant information about the identity of a wine, and prevent consumer deception through the establishment of specific boundaries for viticultural areas. A list of approved viticultural areas is contained in 27 CFR part 9, American Viticultural Areas.

Any interested person may petition ATF to establish a grape-growing region as a viticultural area. The petition should include a description of area's proposed boundaries and United States Geological Survey maps with those boundaries prominently marked, as well as:

- Evidence that the name of the proposed viticultural area is locally and/or nationally known as referring to the area specified in the petition;
- Historical or current evidence that the boundaries of the viticultural area are as specified in the petition; and
- Evidence relating to the geographical characteristics (climate, soil, elevation, physical features, *etc.*), which distinguish the viticultural features of the proposed area from surrounding areas.

The petitioner bears the burden of providing evidence showing that a proposed viticultural area meets the regulatory requirements. ATF utilizes the proposed rulemaking process to facilitate the submission of additional information from the public showing that the proposed area does or does not comply with the regulatory requirements.

Background—California Coast Petition

1998 "California Coastal" Petition

In 1998, a group known as the Coastal Alliance submitted a petition to ATF requesting the establishment of the "California Coastal" viticultural area. The petitioned area's boundaries, extending along the California coastline north from Mexico into Mendocino County 175 miles south of the Oregon border, coincided with the established South Coast viticultural area's southern boundary and with the North Coast viticultural area's northern boundary.

ATF reviewed the petition and determined that the petitioned viticultural area did not meet the regulatory requirements. In the letter denying this petition, ATF noted that the "California Coastal" name could apply to the State's entire coastline and not just to the portion included in the petitioned area. ATF also determined that the petitioned viticultural area's geographic and climatic features were too diverse for it to be considered a delimited grape-growing region distinguishable from surrounding areas.

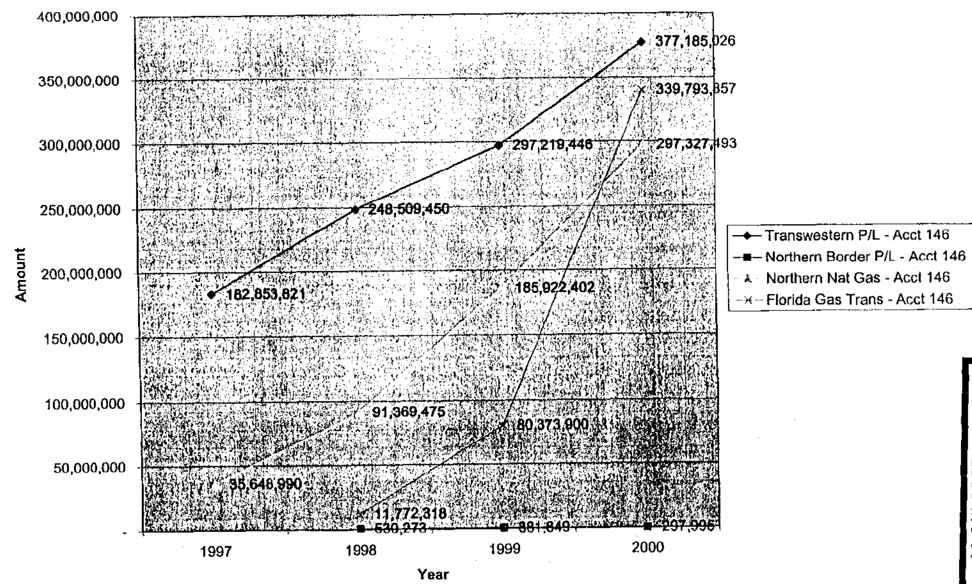
March 2000 "California Coast" Petition

The California Coast Alliance submitted a new petition to ATF on March 17, 2000, proposing the establishment of the "California Coast" viticultural area. The Alliance stated that the California Coast viticultural area would provide consumers with valuable information about the origin of wine made in this area and help prevent consumer deception from the growing

CONFIDENTIAL AND NON-PUBLIC

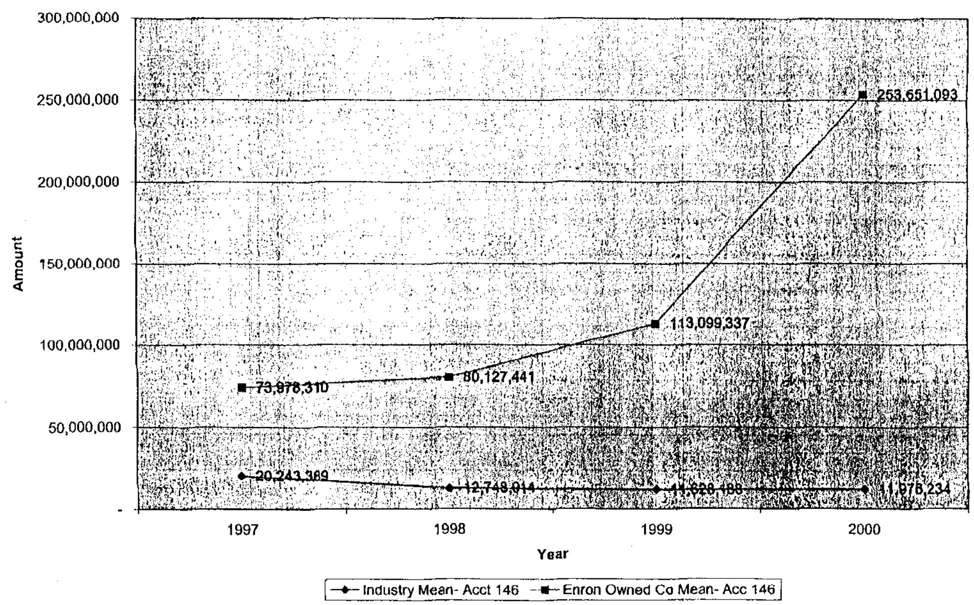
Committee on Governmental Affairs
EXHIBIT #A-44

Account-146 Balances of Enron Owned Companies



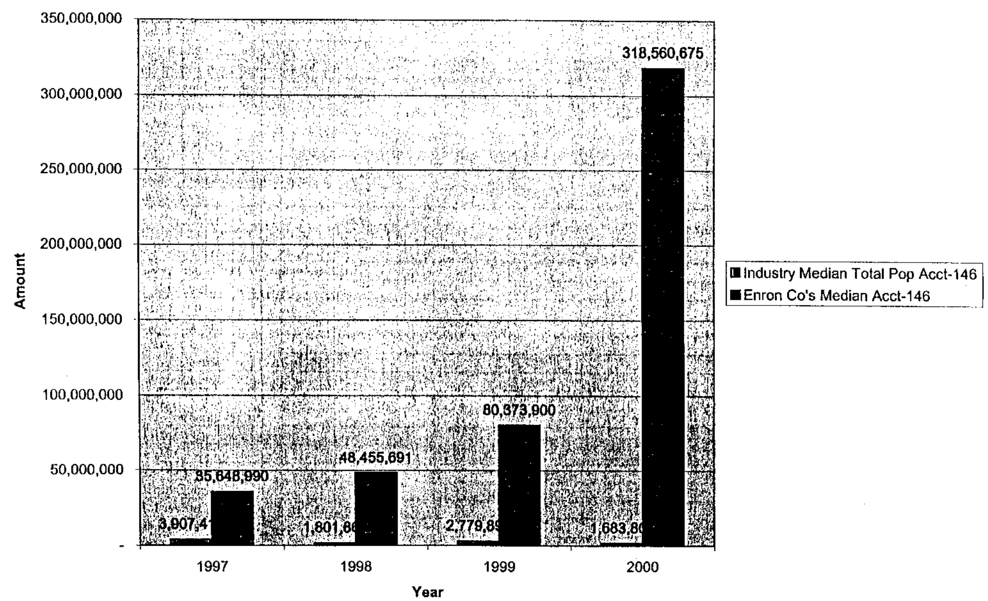
CONFIDENTIAL AND NON-PUBLIC

Total Industry Mean vs Enron Owned Co's Mean- Acct 146

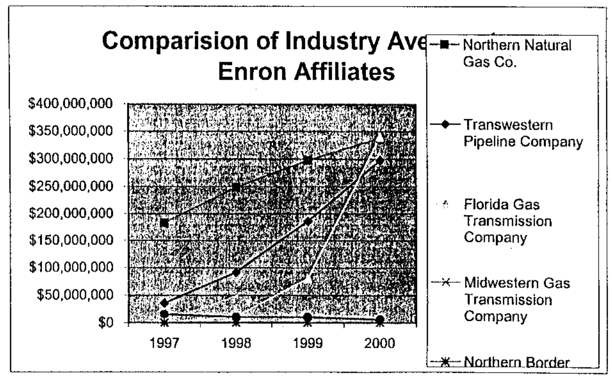


CONFIDENTIAL AND NON-PUBLIC

Indusrty Total Pop Median vs Enron Owned Co's Median



Natural Gas Pipeline Industry Ave	$17,271,888	$14,990,953	$16,964,610	$17,581,433	$16,702,221
	1997	**1998**	**1999**	**2000**	
Average Balance for Enron Affiliated Companies	$44,386,986	$80,127,441	$113,099,337	$194,920,874	$108,133,660
Average Balance for Natural Gas Pipeline Industry Excluding Enron Companies	$15,511,168	$10,761,310	$10,722,096	$6,065,885	$10,765,115



Committee on Governmental Affairs
EXHIBIT #A-45

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Fact-finding Investigation of Potential	)	
Manipulation of Electric	)	Docket No. PA02-2-000
and Natural Gas Prices	)	

RESPONSE OF PORTLAND GENERAL ELECTRIC COMPANY TO THE COMMISSION'S MAY 8, 2002 DATA REQUEST AND REQUEST FOR ADMISSIONS

Portland General Electric Company ("Portland General" or "Portland") submits this response pursuant to the Commission's May 8, 2002 order to sellers of wholesale electricity and/or ancillary services to the California Independent System Operator and/or the California Power Exchange (the "May 8th Order").

SUMMARY OF PORTLAND GENERAL'S INVESTIGATION PROCESS

Portland General became aware of the Commission's May 8th Order the day after it was issued. That Order directs each seller to conduct a thorough investigation into its trading activities and to respond, after conducting that investigation, to certain data requests and requests for admission by May 22, 2002.

Immediately upon learning of the Commission's Order, Portland's General Counsel began assembling a team of senior personnel to formulate and execute the most thorough investigation reasonably possible within the time frame dictated by the Order. While Portland General had no reason to believe that it engaged in any unlawful trading practices – and indeed stands firm in that belief today – given that the company is a subsidiary of Enron Corp, Portland General believed that it was *particularly* important to respond to the Commission's Order with the most thorough investigation possible.[1] Ultimately, Portland General's investigation – conducted with assistance of outside counsel – included the following significant components:[2]

- Creation of an "Investigative Team" (or "Team") – the lawyers on the Team and the staff members assisting them invested over 2,700 hours[3] conducting the inquiry called for by the Commission's Order;
- Circulation of memoranda from Portland General's CEO and from its General Counsel directing employees to fully cooperate with the investigation and specifically requiring that employees search their records and files for any potentially responsive documents;
- Conduct of 74 extensive interviews of individuals who have worked for Portland General, either currently or formerly;
- Execution of an extensive search of hundreds of thousands of electronically stored documents (including e-mails) using approximately 8,500 different computer aided searches for the specific terms used to describe the trading strategies discussed in the Commission's Order – and review of all documents appearing as "hits" for those terms; and
- Engagement in comprehensive follow-up on potentially responsive information – including subsequent interviews of various individuals, as well

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[1] As discussed in greater detail in another section of this submission, while Portland General is owned by Enron, it should be noted that Portland General's trading division at all times maintained *its own* policies and procedures, and that Portland General received legal advice *in its own right*, wholly separate and apart from Enron.

[2] A more detailed description of the investigation is included as Addendum A to this submission.

[3] This figure is a conservative estimate based on time records entered as of the time of this submission.

as review and transcription of voice recordings of particular trading days and transactions.

RESPONSE OF PORTLAND GENERAL

Preliminary Statement

Portland General is an integrated electric utility located in Portland, Oregon, serving approximately 736,000 customers at retail in the state of Oregon. As stated above, the Company is a wholly owned subsidiary of Enron Corp, but it is organizationally decentralized from the parent and managed through its Portland-based management team. Portland General engages in wholesale trading activities, the primary purpose of which is to manage risk, meet its load and reduce costs for its retail customers. Portland General has insufficient generating resources to meet its native load and must purchase significant amounts of power in the wholesale market each year. Consequently, Portland General's trading operations serve the critical function of acquiring resources for native load, balancing those resources with load requirements, and maximizing the value of owned generation and purchase contracts to the extent that available supply is excess to the needs of Portland's firm customers. This trading operation is completely separated from that of Enron Corp. It has at all times operated on a separate, secured trading floor, has its own policies and procedures, and is subject to the Commission's affiliate rules and Part 37 of the Commission's Rules & Regulations. These rules limit the communication that is permitted to take place between Portland General and other Enron companies, and set strict parameters for any inter-affiliate trading.

As part of its routine utility business and in order to take advantage of seasonal diversity between the Pacific Northwest and California, Portland General has both imported power to and exported power from California for over 30 years over the Pacific Northwest Intertie. In fact, this large capacity Intertie system was constructed to facilitate these seasonal exchanges between utilities and to create cost and resource efficiencies in the wholesale power markets of the Western region. The majority of Portland General's sales take place in Oregon, or at the Oregon border.

Portland General is a net buyer of power in these Western power markets, often purchasing in excess of 35% of its retail customers' requirements in the wholesale markets every year. As a net buyer, Portland General's interest and the interest of its customers is advanced when market prices and price volatility in the Pacific Northwest are low.

The Commission's May 8, 2002 order in this docket requests answers to specific Requests for Admissions and Production of Documents. Following are Portland General's responses:

I. Responses to Requests for Admissions

I. 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 of California.

Portland General can neither admit nor deny this question without qualification. As noted above, Portland has purchased power from and exported power out of California for over 30 years to serve its retail load, and frequently resells any power excess to its needs in the wholesale market. This practice existed before the formation and start-up of the Cal PX and the Cal ISO and continues today.

Most of the power purchased by Portland General from the Cal PX during the period 2000-2001 was purchased to serve retail requirements, and, as market volatility increased and security of supply was threatened, to serve as an "insurance policy" that would protect this source of supply for its firm customers. Particularly during the peak demand months of late 2000 and early 2001, Portland General tried to secure additional length in the day-ahead market, rather than rely on the real-time market, because the real-time market was experiencing dramatic price spikes, and the availability of supply could not be guaranteed. These Cal PX purchases were made as part of standard winter buying practice and not as a specific strategy to deprive the state of California of needed power. Nor were they made as part of any specific strategy to circumvent price caps in the California market. As a retail service provider and as a net *purchaser* of power, increasing power costs and price volatility would not have been in the best interest of Portland General.

Further, when Portland General purchases power, it is then combined into a larger, blended portfolio of supply that is available for serving its retail load or for resale to numerous potential purchasers in the wholesale market. If ultimate prices were higher in the real-time market than the prices at which Portland had purchased in the day-ahead market (and assuming that it had excess to sell in any particular hour), then, obviously, resales from the portfolio would have been made at a profit. In that profit motivation did exist, resales most likely would have been made to the highest bidder, regardless of whether the bidder was located in the Pacific Northwest or California. Conversely, the company was at a risk of loss if real-time prices decreased below the price paid to Portland General's suppliers, including the Cal PX, in the day-ahead market or forward market. Portland General also was taking a risk of highly volatile real-time pricing if it had not purchased sufficient supply in the day-ahead market and had to purchase additional supply in real-time. Finally, it is important to note that tracing the resale of any particular megawatt in a blended portfolio of supply back to its source is theoretically impossible, notwithstanding bookout accounting practices or, for example, the periodic occurrence of "sleeve" transactions.

Given that it had neither the incentive nor the intent to participate in a strategy to deprive California of power or to increase prices in its own retail marketing area, Portland General does not believe that it has engaged in the strategy contemplated in the Enron memoranda or by the Commission's request for admission I.A.1. However, some transactions conducted by Portland General during 2000-2001 may have resulted in the company purchasing power from the Cal PX and reselling power from its portfolio of supplies at prices higher then those paid to the Cal PX.

I. A. 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.

Portland General submits that it is not possible to trace purchases into and sales out of a blended portfolio of supply, as seemingly contemplated by this question. However, for transaction data potentially relevant to this question, Portland General refers the Commission to information filed by Portland General in this Docket No. PA02-2-000 pursuant to a request from the Commission in an order dated March 5, 2002.

Also see Attachment I.A.2.

I. 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.

Denied.

I. B. 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 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.

Not applicable.

I. 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.

Denied. It is possible that, unknown to Portland General, it could have been used by a third party in partial execution of this strategy. See Responses to Questions I.K.1 and III.B.

I. C. 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.

Not applicable.

I. 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.

Denied.

I. D. 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 all congestion payments received. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. 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 canceling 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.

Denied.

I. E. 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.

Not applicable.

I. 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.

Denied.

I. F. 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.

Not applicable.

I. 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 it 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 include the generation of other sellers.

Denied.

I. G. 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.

Not applicable.

I. H. 1. Admit or Deny: The company engaged in activity described in the Enron memoranda as "**Ricochet**," also know 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.

Denied. See, however, Response to Question I.K.1. Portland General may have been used as an intermediary by another party engaging in a similar activity.

I. H. 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 resold. Also, provide all documents that refer or relate to the activity described immediately above.

Not applicable.

I. 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.

Denied.

I. I. 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.

Not applicable.

I. 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.

Denied.

I. J. 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.

Not applicable.

I. 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.

This request is so vague and far-reaching that it cannot be answered without Portland General speculating as to what it covers. Many trading products and services legitimately involve activities such as relieving congestion (*e.g.*, "circulation" transactions, requested of Portland General by the Cal ISO), providing control area services to marketers that they cannot provide themselves (*e.g.*, "parking and lending"), or bidding practices (*e.g.*, "incremental" and "decremental" bidding) that are necessitated by the California market design. However, if the intent of the Commission is to inquire into trading activities that involve knowingly submitting false load or delivery schedules, misrepresenting non-firm commitments as firm, causing artificial congestion, or receiving congestion payments without actually relieving congestion, then Portland General denies that it engaged in any such activity.

Although Portland General denies engaging in the strategies described in the Enron memoranda, or variants thereof, as a result of its investigation (and after reviewing and reaching what it believes is a basic understanding of the general nature of the strategies described in the memoranda), the company discovered that services it provided may have been used by third parties, such as an Enron Corp subsidiary ("Enron"), as a step toward execution of some of those strategies. For example, Portland General speculates that it *could* have been used by Enron to provide one of the steps leading into the I.C.1. strategy, although it had no knowledge of such possibility until the investigation. See Response to Question III.B. Further, after gaining an understanding of the strategies set forth in the memoranda, it is conceivable that other services provided by Portland General, such as its "Park and Lend" service, may have resulted in Portland General being used as an intermediary in partial execution of one or more of the strategies. Information describing "Park and Lend" is provided in Attachment I.K.1.

I. K. 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.

Not applicable.

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.

Portland General Response:

To the best of Portland General's knowledge and belief after thorough investigation (see Addendum A), it is providing all material that it has identified as responsive to the request in Attachment II.A. Also see the material attached in response to Question III.B.

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 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.

Portland General Response:

To the best of Portland General's knowledge and belief after thorough investigation (see Addendum A), it is providing all material it has identified as responsive to the request in Attachment II.B. Also see the material attached in response to Question III.B.

Based on its investigation Portland General believes that various individuals in its organization had some level of awareness of certain of the trading strategies (or variants thereof) discussed in the Enron memoranda. The level of awareness is generic, possibly gained at an industry seminar or through a consultant's event report that may have been circulated on the internet or even through the ISO's public discussions of known interpretations or uses of its tariffs. In some instances (*e.g.*, "ricochet"), the term had general industry connotations. "Ricochet" has been used generically in the industry as a description for certain transmission paths and also in reference to the development of a potential NYMEX product. The generic knowledge of these terms by Portland General employees did not rise to the level of specificity that enabled them to define the strategies in detail or identify particular companies engaging in these strategies, other than as specifically reported herein. In its internal investigation, Portland General did not uncover instances or recollections where the company, itself, had engaged in or knowingly aided these strategies, except, again, as specifically reported herein.

III. Requests for Other Information

A. On page 2 of the December 8, 2000, Enron memoranda, 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.

Portland General Response:

Portland General did not formally model what appears to have been a deliberate underscheduling of load by some or all of the California investor owned utilities. Expert traders did, however, take into consideration this well-known underscheduling in determining their daily bids.

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.

Portland General Response:

Portland General has discovered 17 days during the April-June 2000 timeframe in which it was used as an intermediary in transactions that commenced with an Enron purchase from a California entity. Although these transactions do not fit the precise definition of a ricochet transaction, they appear similar. The exact counter party from which Enron took receipt in these transactions is unknown in most instances. The power was then sold by Enron to an independent third party, who resold the power to Portland General. Portland General then further resold the power to Enron. Enron took the energy south. Attachment III.B. provides a summary of the details of these transactions, prepared by Portland General on May 21, 2001. Attachment III.B. also includes the accounting logs for these transactions. Information discovered by Portland General since May 8, 2002, followed up with a review of trading floor telephone tapes for the transactions in question (see transcriptions of these conversations in Attachment III.B.), indicate that the service provided by Portland General during these days may have been used by Enron as one step of the strategy described in I.C.1.

LeBoeuf, Lamb, Greene & MacRae
L.L.P.
A LIMITED LIABILITY PARTNERSHIP INCLUDING PROFESSIONAL CORPORATIONS

633 Seventeenth Street
Suite 2000
Denver, CO 80202

Committee on Governmental Affairs
EXHIBIT #A-46

August 2, 1999

TO: File

FROM: John Maas

RE: Power Transaction

FACTS

Note: Some of this requires further investigation and may be more or less incorrect.

The facts contemplate a potential power transaction between two companies: "EPMI," a large power marketing concern (which is not a utility and whose only business is trading power) and PGE ("Affiliate") an electric utility regulated by the Oregon Public Utility Commission. Affiliate and EPMI are wholly-owned subsidiaries of the same ultimate parent, Enron Corp.

The parties intend to enter into a contract (for an unspecified term) providing for Affiliate to serve as the "sink" for any large power transactions (say, 400MW) entered into between EPMI and any third parties (but not Affiliate) for delivery of such 400MW from anywhere in California or Nevada to one of several standard delivery points located at the California-Oregon border ("COB"). The "sink" is the jargon used to generically refer to the party into whose "control area" (a utility electrical system providing power to end users in a specified territory) the power transmitted in connection with a power transaction "leaves the transmission system," and does not necessarily mean the ultimate buyer of the power (i.e., the "sink" could be responsible to transmit the power further along to another party or could have agreed to receive the power on another party's behalf). The "source" is the point where the power in the transaction enters the transmission system for purposes of the power contract and could be the point of interconnection with a generating plant or simply a point at which the seller takes "delivery" of the power from its seller in turn. Power flowing north (and south) from California to the Pacific Northwest generally flows on a very large 500kV transmission system known as the Pacific Northwest Intertie ("Intertie"). The Intertie is a key resource to flow power north to south from the Pacific Northwest into California during periods of peak usage in California.

Under the contract, Affiliate will receive a fee for agreeing to be obligated to serve as the sink for all power which EPMI contracts to sell to third parties who can take delivery at COB or otherwise in the Pacific Northwest. However, EPMI has no real plans to enter into any such contracts and Affiliate knows that it is unlikely to ever be called to serve as such

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sink. Rather, the sole commercial purpose of the transaction is to afford EPMI the ability to "schedule" with the California Independent System Operator ("ISO") the 400MW of power for transmission from South (California) to North (COB) on the Intertie each day or whenever it wishes to do so, even though it does not, at the time of such scheduling, have either a contract to sell the power to a third party or, at the time of the scheduling, any present intention to enter into such a contract. EPMI cannot schedule the power without providing the identity of the source and sink. The scheduling would be done simply to reserve the necessary transmission capacity with the ISO, solely on a "non-firm" or interruptible basis (that is, if the ISO needs the transmission capacity for a more important or "firm" transaction, it can "bump" EPMI from the schedule at any time) in case EPMI were to find an opportunity to enter into a favorable transaction, although, as stated, it would have no actual intention of doing so at the time of the scheduling.

The ISO is an organization in California charged with scheduling all of the power flows across the transmission system for each hour of each day in California. The ISO has a tariff on file with the Federal Energy Regulatory Commission ("FERC") which provides for the prices and terms under which parties can acquire and reserve transmission on the system ("ISO Tariff") and FERC has exclusive jurisdiction over all "wholesale" power transactions in the United States. A wholesale transaction is between two parties neither of whom is the end user of the power. "Retail" transactions are where one of the parties actually consumes the power (i.e., to keep the lights on or run machinery) and are regulated exclusively by the state PUCs.

Early in the morning of each day, all of the certificated "scheduling coordinators" in California (including EPMI) must provide their schedules for power transactions and flows to the ISO for the next day so that the ISO can "balance" the transmission system. This is necessary because, due to the physical properties of electricity and power lines, if there is an imbalance between the amount of power put into the system by generating plants and the amount of power taken out of the system by end users, the system will "crash," much like our computers but with even more annoying results. The ISO's job is to make sure this doesn't happen while treating all users of the system fairly and equally with respect to priority of their transactions. The ISO must balance the system by obtaining other power or reductions in power input into the system (or in some cases, reductions in power taken out of the system) and this power is known as "ancillary services."

All power to be put into the system in California, is required to be "sold" through the California Power Exchange ("PX"), which basically acts as a market clearinghouse to set the prices and availability of power in California, except for certain ancillary services which the ISO can acquire directly from any party having them available for sale. Just like the ISO, early in the morning of each day, all parties who have power to sell into the system must "bid" the power into the PX, showing the amounts, hours and prices at which they are willing to sell. The ISO tells the PX how much power will be needed and for what hours, based upon the "day ahead" schedules filed by the scheduling coordinators, and the PX selects the parties

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to provide the power based upon their bids, going from lowest to highest (the price, I think, for everyone for a particular hour is the highest price that the PX reaches in order to satisfy the demand). (This is simplified to a considerable degree for our purposes.) With respect to ancillary services however, particularly for large, urgent transactions, the PX is not used and the ISO must pay whatever the market may be in order to preserve the balance of the system.

Power transactions, however, are constantly changing due to weather conditions and many other factors; therefore, it is necessary for the ISO to constantly adjust its schedules as each day and hour approach. The scheduling coordinators are required to update their schedules to reflect changes in their transactions and this often takes place in the "hour ahead" time frame, since the likely ultimate demand in a particular hour cannot finally be known until very close to the real time thereof. Thus, in our transaction, EPMI will file an "hour ahead" schedule releasing the non-firm transmission capacity it previously scheduled for its 400MW moving south to north over the Intertie when it files its schedule for the hour preceding the hour when that transaction otherwise would have begun.

Whenever this happens, there is created an imbalance in the system because the ISO was planning for this 400MW to be input into the system at the source (somewhere in California) and to be taken out of the system at COB by the sink, Affiliate and had arranged to balance the system accordingly. When a relatively small amount of power is involved, it is easy for the ISO to obtain the ancillary services necessary to manage this imbalance. However, if a very large amount is involved, such as our 400MW, it is more difficult for the ISO to obtain the ancillary services, especially at times of peak usage, because all of the generators are already committed and running full tilt and there is very little time in which to act. At such times, the laws of supply and demand operate to give a party that has power available a premium price. EPMI plans to have power available to take advantage of this opportunity which it will, in effect, to some degree have created. The result will be that the ultimate parties buying power in California to balance their systems and serve their end users (the utilities) will pay the ISO more for such power than they otherwise might have done had the 400MW not been scheduled and withdrawn.

EPMI and Affiliate believe this arrangement, while admittedly unusual, is lawful under the ISO Tariff because the ISO Tariff, apparently (I will be looking at this) does not require a transaction to have been already entered into as a prerequisite for having your scheduling coordinator schedule the amount of power for the transaction on a non-firm or interruptible basis, which is inexpensive because it can freely be bumped. This, EPMI believes it is acceptable under the ISO Tariff to schedule transmission for power that you know you are unlikely to need, or even that you know you will not need.

EPMI believes this represents a window of opportunity or "loophole" in the design of the new competitive marketplace in California which can be exploited to make a profit when the ISO has to "scramble" at the last minute to obtain ancillary services necessary to balance

3

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the system when the 400 MW non-firm schedule is withdrawn at the last minute. Because this market is new and developing, various parties have been able to exploit other such loopholes and make large profits as a result, but, insofar as we are aware, none of those transactions has involved a contract or agreement between two parties (or affiliates) but only a single party "gaming" the system by, say, the way in which it structures its bids for power to the PX. Many of these parties, particularly the utilities or very large generators, have information unavailable to the rest of the market that enable them, in EPMI's view, to manipulate the process to varying degrees that would not work if the market were fully informed.

The response so far of the entitiess charged with making this market work - the PX, the ISO and several market surveillance or compliance committees - has largely been to conduct investigations and make reports to the California regulatory authorities and FERC and then to file a revised ISO Tariff seeking to close the loopholes and make the market more efficient. EPMI feels that if this is likely to be the only response to the proposed transaction, then it would be foolish not to exploit the loophole to make a profit for its shareholders until the locphole is closed. However, if EPMI or Affiliate could be exposed to substantial damages or fines or other penalties, whether criminal or civil, then it will not enter into the proposed transaction. Affiliate has asked us to advise it on this question and whether it should agree to serve as the sink for the proposed transaction.

Transcripts of Portland Scheduling Calls
04/15/00

Committee on Governmental Affairs
EXHIBIT #A-47

04/15 – 10:04

PGE: Portland, this is Ken.

Enron: Hey Ken, John Forney at Enron.

PGE: Yeah.

Enron: I just talked to Judy a little while ago.

PGE: Yeah, I am here.

Enron: Hi ya Judy. It looks like we are going to take those 24 megawatts out of the ISO and sell that to and go to Portland General, it's going to Water Power, then to Portland General, and then I am using my transmission to go from John Day to Malin.

PGE: Okay.

Enron: And I've talked to Water Power, and I've talked to Portland General Transmission, and you, and now I am going to call LA transmission because we are passing it off to them at Malin. And it's 24 megawatts for hour 12. And I may go to hour 13 as well but I will advise.

PGE: Okay, sounds good.

Enron: Okay. Thanks Judy.

PGE: Okay. Bye-bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 10:26

PGE: Portland. This is Judy.

WWP: Yo, Judy this is Ron.

PGE: Hi Ron.

WWP: Howdy. Yeah, evidently, what he's going to do is bring it up. And I bought the transmission from Portland to get it to John Day. And John Day is where I sell it back to you?

PGE: Sell it to Portland?

WWP: Yeah.

PGE: Oh, I didn't know I was buying anything, because nobody has said anything to me about prices or anything.

WWP: Okay, what it is …

PGE: My understanding was it was strictly a transmission transaction.

WWP: Maybe you better talk to Enron because he said that I'm sleeving it just because you can't buy it. They can't sell it to you. And I don't know what the deal is cause I told him well, [expletive], I don't have transmission if I have to buy the transmission then I gotta go buy it for 16 sell it for 19. And I don't know if you really want to do that.

PGE: Yeah, I don't know that I want to be in the middle of that.

WWP: Why don't you call him? I was talking with Enron and I'm not really familiar with this, they said they only did it on a prescheduled basis. Well, that's a lot easier …

PGE: Well, preschedule is one thing. Real-time is a pain in the butt.

WWP: It's getting that way real fast. 24 megawatts, like, I really don't give a rip.

PGE: I'll have to call him back because it sounds like this is something he wanted to do all day and I thought if he wants to just buy transmission to do something … that's fine. I don't care. I wouldn't even see it. But, if we have got to go through setting up a bunch of hokey accounts and horse it around.

WWP: Yeah, I'm not really sure where the hell to put this. You know, do I put it in a memo account or does Bonneville have to know about it? I don't know. Anyway, I've been talking with Robert on your transmission and John from Enron and I don't know where to put the numbers.

Transcripts of Portland Scheduling Calls
04/15/00

PGE: Let me call you back.

WWP: Thanks, Judy.

PGE: Okay. Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 10:28

PGE-Trans: Portland, this is Robert.

PGE: Yeah, Robert, this is Judy.

PGE-Trans: You're patient on the phone! You had nobody else to talk to anyway. So what is this deal now? Do you know about this bogus deal?

PGE: Well, I thought they were just buying some transmission and it was something I would never see. And all of a sudden, somebody says I'm buying and selling energy and that wasn't my intent.

PGE-Trans: Did you talk to Enron about this?

PGE: I haven't called them back. No. I wanted to talk to you guys … see what your understanding was.

PGE-Trans: Well, see, what they told us … what they're trying to do, is because of the FERC requirements where they can't sell directly to us, they've got power that they're bringing up from the ISO and then they are going to sell it to Water Power at the border. And then Water Power is going to sell it to us or drop it off … give it to us at John Day … using our transmission. So, its coming into our system at John Day. Okay? And then, we're going to turn around and sell it to Los Angeles.

PGE: We are?

PGE-Trans: That's what we're supposed to do.

PGE: Hey, I don't have DC transmission to sell it back to Los Angeles.

PGE-Trans: Well, you know I don't if it was supposed to go on the DC. I'm assuming that that was supposed to go down on the AC. Okay?

PGE: Well now, if they're sending it back on the AC, I don't have AC transmission to send anything back.

PGE-Trans: Okay, but see, the way we're doing the curtailment is you actually do have … we do have transmission you can use assuming that the ISO they'll take it south. If they'll take your schedule it will flow.

PGE: Well, why don't they just buy it from you? Why do they have to go through me? I don't know why I have to be involved.

PGE-Trans: Well, because I think the thing is that we're selling it out of our system. The power is coming out of us. And when we did this thing last time … I don't know … is Chris with you? The big Chris?

Transcripts of Portland Scheduling Calls
04/15/00

PGE: Uh, he's not here right now.

PGE-Trans: Okay. I don't know which one of the other marketers is the one that did this thing because they've done this like once before.

PGE: Well, somebody said it was done preschedule. Nobody's done it real-time.

PGE-Trans: Oh, Okay. Yeah, because I haven't done this thing either. And the Water Power guy wasn't sure what he was doing either. So all I am saying is at this point in time if you're not comfortable doing this thing, I guess we won't do it. Until they can tell us exactly how this thing is supposed to go.

PGE: Yeah, I'm not real comfortable with it. I don't know how I'm supposed to show all this stuff.

PGE-Trans: I mean, I suppose, unless your boss knows or somebody else there knows works with you guys on how they do this thing. But otherwise you're just poking around in the dark on this.

PGE: Yeah, I thought they were just buying transmission ...

PGE-Trans: Yeah, well, like I said for all parties concerned so far it doesn't, it's not one of these ...

PGE: ... to sell to Water Power and for Water Power to sell to LA.

PGE-Trans: Whether we can't support it, we can't do it, I guess.

PGE: No.

PGE-Trans: Okay. 'Cause I haven't called anything in. I mean, Water Power, he wasn't sure what he was doing.

PGE: Well, I'm going to call 'em upstairs and talk to them.

PGE-Trans: All right.

PGE: Okay. Bye.

Next Call:

PGE(in background): I'm calling Enron.

Enron: Enron. Stan speaking.

PGE: This is Judy downstairs at PGE.

Enron: Yeah.

Transcripts of Portland Scheduling Calls
04/15/00

PGE: I wanted to talk to somebody about this thing with LA and the ISO.

Enron: Actually, my buddy John Forney has been putting that together. Let me let you speak with him. Hold on one moment.

Enron: This is John.

PGE: Yeah John, this is Judy at PGE. About this deal with Water Power and stuff, nobody seems to know how to put this together.

Enron: Okay. Bill Casey put this deal together and he may be of some assistance. I don't know if, uh ...

PGE: Of course he's not here today.

Enron: Right. I don't think, you know when Water Power was involved on a prescheduled basis that we had to worry about them buying a wheel from Portland transmission but just in the interest of smoothing things out I told Ron at Water Power I would reimburse him for that wheel.

PGE: Well, you know, I don't have any idea how this is supposed to work. This is something normally preschedulers set up and on real-time nobody that's here knows what's going on. Everybody's just scratching our heads.

Enron: Should I call Bill Casey or something? 'Cause I called well in advance to get this done. I was hoping we could get everything taken care of up front.

PGE: Yeah, um, I don't know what to do with it to tell you the truth.

Enron: Should I call ... do you have the number of Bill Casey?

PGE: Um, gosh where is his number? Nuts, they got all our boards down here because we're in the process of moving. Crap, and I've got other cuts and things that I gotta take care of.

Enron: Still, I got it in there for the next few hours and I want to just go ahead and ...

PGE: Yeah, I don't know how to show it. I'd rather not be bothered with it at this time when I've got so much other stuff to deal with.

Enron: Yeah, if we get it in that first hour, though, it should all be taken care of.

PGE: Bill's number: [redacted].

Enron: Okay. Let me give him a call.

PGE: Okay.

Transcripts of Portland Scheduling Calls
04/15/00

Enron: Thank you. Bye.

PGE: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

4/15 – 10:48

PGE: Portland. This is Judy.

WWP: Yo, Judy, this is Ron.

PGE: Hi Ron.

WWP: Did you talk with Enron?

PGE: Yes, and I told them that I'd rather not be involved in it and he said he was going to call my boss.

WWP: Oh, [expletive]!

PGE: So that's where it's sitting. I gave him Bill's home number.

WWP: Well, I don't know, I'm not quite sure what to do here.

PGE: I don't know what Bill is going to tell him but he hasn't called back and gosh, and it's been … it's been a little bit since I talked to him.

WWP: Okay. Well, I guess, I had talked to Roger who said that if I could get it up to Malin, I mean up to John Day and could sell it to you at John Day, I think I could do that in a memo account. But, yeah, I would just kinda be a marketer in the deal.

PGE: We would both be marketers.

WWP: Yeah, well I guess so. Yeah, because you would just turn it around and sell it to somebody else. You don't want it.

PGE: If he's got it at COB, why doesn't he just sell it to LA at COB?

WWP: That … and the whole thing it just seemed kinda bogus because the guy from LA called and he wanted to sell at Malin and so I can't picture him wanting to buy … I don't know what's going on but maybe I better go find out.

PGE: Yeah.

WWP: Okay.

PGE: Okay.

WWP: All right Judy. Bye.

PGE: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

4/15 – 10:53

PGE: Portland. This is Judy.

Enron: Hey Judy. John Forney at Enron again.

PGE: Yes John.

Enron: Did Bill give you a call?

PGE: No.

Enron: I talked to Bill and he said that the confusion should be taken care because we are making a sale to you. I'm selling to Water Power and Water Power is selling to Portland at Malin. So, Water Power shouldn't have to buy transmission from Portland General.

PGE: But then what is Portland doing with it?

Enron: Portland is taking it up to their system and then I'm buying ... using my wheel from John Day to Malin, and then we are passing it off to LA transmission.

PGE: Oh. How come he didn't just sell to LA at Malin?

Enron: Because I have to have a northwest utility to take it south. And Ron with Water Power tells me that he can't ... he doesn't have the transmission to get it to LA. He's just a PSC. Because I can't sell directly to Portland General. Does that make any sense?

PGE: Yeah. I'm still not sure how this has to be shown or whether we have accounts for it.

Enron: We did it last week. I was trying to get all the confusion out of the way a couple of hours ago because I'm going to be doing it again for 13.

PGE: Oh boy.

Enron: Hopefully, this helps some. I talked to Bill. I don't know whether he was at a ball game or what. But he was saying also that you guys need to post some capacity or something on the bulletin board.

PGE: Hold on just a minute. Oh, Bill's on the other line. Let me talk to him.

Enron: Very good.

PGE: Okay.

Enron: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

Next Call:

PGE: Hello Bill?

PGE2: Hello Judy.

PGE: What on earth is this guy talking about?

PGE2: It's just a buy/resell. You do a buy/resell with Water Power and a buy/resell with Enron.

PGE: I thought I wasn't supposed to sell to Enron.

PGE2: No, you can do buy/resell as long as it's at market.

PGE: As long as what?

PGE2: As long as it's at market--market price. So, index, index is market price.

PGE: Oh. I have no idea how I'm supposed to show this.

PGE2: You buy from Water Power at COB from the ISO.

PGE: From COB.

PGE2: So that you have a firm ISO/Water Power account.

PGE: Would this be in the Water Power accounts or the ISO accounts?

PGE2: Either.

PGE: Either.

PGE2: ISO interchange, Water Power, schedule group.

PGE: Hold on just a minute. Okay, from ISO/Water Power or from Water Power/ISO?

PGE2: Its ISO/Water Power. It's an ISO interchange.

PGE: Find ISO, let's see if it will come up here, to ISO/Water Power, from ISO/Water Power firm, that's not it.

PGE2: That's the one.

PGE: That is it, the firm?

PGE2: The firm ISO/Water Power. Its gotta be at COB, right?

Transcripts of Portland Scheduling Calls
04/15/00

PGE: Yeah.

PGE2: Okay. So, you put it in there--you agree on a price with Water Power, Okay?

PGE: Oh. Okay, so, I have to negotiate a price with Water Power.

PGE2: No you just set a price. You're going to be price neutral on this. So, for accounting purposes you just set a price so that when we try to check out, at the end of the month, all the dollars and megawatts match up.

PGE: Okay, and then how do we show it on the other side?

PGE2: On the other side it's on the "To BPA/Enron John Day," Okay? So, it's BPA interchange or Enron schedule group ... whichever one.

PGE: Okay. Let me get the Enron schedule group up here. Okay. I'm looking for "To BPA/Enron."

PGE2: PGE/John Day or something like that. It says JD right on it.

PGE: To BPA, PGE, Enron, John Day. We've already got a bunch of stuff in here.

PGE2: So, in the details put it in the hour for the amount. And just put point 4, which is 40 cents.

PGE: Okay, that was ... what did you say, point 4?

PGE2: Yeah, 40 cents. Now this is for hour 13 I'm assuming.

PGE: It was supposed to be in there for 12 also. He wants to do it all day.

PGE2: Well, is BPA gonna let you put it in for 12?

PGE: I don't know.

PGE2: Well, then I wouldn't tell you could do it for 12 if BPA won't put it in. Here, let me call you right back.

PGE: Okay.

PGE2: Thanks.

PGE: Uh huh. Bye.

Next Call:

PGE: Hello.

Transcripts of Portland Scheduling Calls
04/15/00

Enron:	Yes.
PGE:	Yeah, uh, Bill is going to be calling. We gotta find out if BPA will take the schedule for hour 12. But we'll put it in for 13. How many hours did you want it in?
Enron:	It will probably be going every hour until further.
PGE:	Okay, so you'll be calling me every hour?
Enron:	Yes ma'am. I will.
PGE:	Okay, I'll go ahead and get it in for hour 13. Bill's either going to be calling you or calling BPA. He didn't say.
Enron:	Okay. All right. Well, hopefully, we can get it for 12 because I already have it in place.
PGE:	Okay.
Enron:	Thank you, Judy.
PGE:	Okay. Bye.

Transcripts of Portland Scheduling Calls
04/15/00

4/15 – 11:03

BPA: BPA transmission. This is Vicky. May I help you?

PGE: Yeah, Vicky, this is Judy at Portland.

BPA: Hi Judy.

PGE: We have an account BPA-Enron for Portland to John Day. 740768 is the account number.

BPA: 740768 is your Portland – John Day?

PGE: Yes. Okay, that account for hour 13 is increasing by 24. I think you had 82 in there it goes to a 106. Now we'd like to increase that to 106 for hour 12 also. Will that work?

BPA: Hang on just a second. Okay, it's done.

PGE: Okay. That's it for now.

BPA: Okay.

PGE: Thank you.

BPA: Thank you.

PGE: Bye-bye.

Next Call:

PGE: Hi Robert.

PGE-Trans: Hey, what did you ever decide on this?

PGE: Jeez, what a mess! What a pain in the rear. I guess we're going to do it and what it amounts to is we have an account that goes BPA-Enron-Portland to John Day that is 82MW and that will increase to 106.

PGE-Trans: Okay, now did we do that for this hour?

PGE: Hour 12 and 13. I've put 12 in. I haven't put 13 in yet.

PGE-Trans: Okay, so what was the actual change then? Total?

PGE: Total change is 24MW.

PGE-Trans: So, now its 24 coming to us?

Transcripts of Portland Scheduling Calls
04/15/00

PGE: Uh, going out.

PGE-Trans: Going out.

PGE: Yes.

PGE-Trans: And it's going to be the same thing for 13?

PGE: Yes.

PGE-Trans: So, basically, I can see we're off by that hour, 24.

PGE: Yeah.

PGE-Trans: So it would be from us to ... who's it going to?

PGE: Well, it's going to the ISO ... er, excuse me, it's going to LA.

PGE-Trans: PGE to LADWP, 24.

PGE: Right.

PGE-Trans: Okay.

PGE: Okay.

PGE-Trans: All right.

PGE: Thanks. Bye.

PGE-Trans: Bye.

(Next call involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 13:06

PGE-Trans: Portland, this is Robert.

PGE: Robert, this is Judy. Okay, hour 15, I want to be sure we've got everything in here.

PGE-Trans: Okay.

(Discussion of separate transaction)

PGE: Okay, got that. Uh, and then the 24's with Water Power and Enron are in.

PGE-Trans: Okay, I got that.

PGE: Okay, good you've got everything you need then.

PGE-Trans: Okay.

PGE: Okay. Thanks.

PGE-Trans: Uh-huh.

PGE: Bye.

(Next three calls involve separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 14:05

PGE: Portland, this is Judy.

Enron: Hey Judy, John Forney at Enron.

PGE: Yes.

Enron: Hey, just calling about our pet 24 megawatt project here?

PGE: mm-hmm.

Enron: The same thing for next hour is going to Water Power.

PGE: Okay …

Enron: Out of Malin.

PGE: Okay. Repeat?

Enron: Repeat.

PGE: Okay, we'll do it.

Enron: Thank you.

PGE: Bye-bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 14:27

PGE: Portland, this is Judy.

PGE-Trans: Hi, this is Robert!

PGE: Hi Robert!

(Discussion of separate transaction)

PGE-Trans: We're not doing that 24 thing?

PGE: Oh, oh, oh, yes we are.

PGE-Trans: Oh, we are?

PGE: We are, I'm sorry. We are doing the 24 thing.

PGE-Trans: 24 thing again?

PGE: Yeah.

PGE-Trans: Okay.

PGE: Thank you.

PGE-Trans: Okay.

PGE: Bye.

PGE-Trans: Bye.

(Next call involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 15:06

PGE: Portland, this is Judy.

Enron: Hey Judy, John Forney-Enron.

PGE: Yes, John!

Enron: Did I tell you that hour 17 was a go for our 24 megawatt schedule?

PGE: No.

Enron: Okay.

PGE: Okay, we'll put it in.

Enron: Thank you very much.

PGE: mm-hmm.

Enron: Bye.

PGE: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 15:37

PGE: Portland, this is Judy.

PGE-Trans: Hi Judy, are we doing the 24s again for 17?

PGE: Yes, we are.

PGE-Trans: We are?

PGE: 24 for hour 17. I haven't heard on hour 18, but the 150 with the CPX is going to zero for hour 18.

PGE-Trans: Also.

PGE: Umm-hmm.

PGE-Trans: Let's see. Okay, that's not in yet. Okay, I got it for 17. Okay, so we're doing the 24 again for 17 then?

PGE: Right

PGE-Trans: Okay.

PGE: Thank you.

PGE-Trans: All right.

PGE: Bye.

PGE-Trans: Bye.

(Next call involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 15:49

PGE: Portland, this is Judy.

Enron: Hey Judy, John Forney again.

PGE: Yes sir.

Enron: I just wanted to check with you and tell you hour 18 is repeat 24 megawatt schedule, going to Water Power.

PGE: Okay, we'll put it in.

Enron: Thank you.

PGE: Umm-hmm.

Enron: Bye.

PGE: Bye-bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 16:24

(First call forwarded to another party)

PGE: This is Judy.

PGE-Trans: This is Robert.

PGE: Hi Robert.

(Discussion of separate transaction)

PGE: We've got the 24s in again.

PGE-Trans: 24s again?

PGE: Umm-hmm.

PGE-Trans: Okay.

PGE: And let's see … and that's it.

PGE-Trans: Okay.

PGE: Okay.

PGE-Trans: Bye-bye.

PGE: Thanks.

PGE-Trans: Bye.

PGE: Bye.

(Next call involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 17:16

PGE:	Portland, this is Judy.
Enron:	Okay Judy, John Forney at Enron.
PGE:	Yes sir.
Enron:	Hey I just gonna call to tell ya for hour 19.
PGE:	Umm-hmm.
Enron:	We've got a repeat.
PGE:	Okay.
Enron:	24 megawatts going out of the ISO at Malin going to Water Power and then to you.
PGE:	Okay. I'll put it in.
Enron:	Great.
PGE:	Thank you.
Enron:	Thank you.
PGE:	Bye-bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 17:20

PGE: Portland, this is Judy.

PGE-Trans: Hi Judy, this is Robert.

PGE: Hi Robert. You must have seen me put that 24 in?

PGE-Trans: No, I have not seen that on the screen. What? We're doing the 24s again?

PGE: Right.

PGE-Trans: Correct.

PGE: Umm-hmm.

PGE-Trans: And that's it.

PGE: Yeah, no change on the AC.

PGE-Trans: Okay, as far as no more PX stuff?

PGE: Right.

PGE-Trans: Okay, so the 24 is again?

PGE: Umm-hmm.

PGE-Trans: Okay.

PGE: Right.

PGE-Trans: Okay.

PGE: Thank you.

PGE-Trans: Umm-hmm.

PGE: Bye-bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 17:57

PGE: Portland, this is Judy.

Enron: Hello Judy, this is Jeremy over at Enron.

PGE: Yes.

Enron: Can you please hold on for a second?

PGE: Umm-hmm.

Enron: Hello?

PGE: Yes.

Enron: Judy, I'm sorry about that. Umm, we have 24 megawatts coming out at Malin?

PGE: Umm-hmm.

Enron: And we're gonna use and buy resale from Washington Water Power to you, you're gonna pick it up at Malin. We've been doing this all day.

PGE: This is just … this is a repeat. With 24 megawatts.

Enron: Yeah, we're doing a repeat. And then it's gonna be … we're gonna use our transmission from John Day to Malin to LA.

PGE: Umm-hmm.

Enron: Got it?

PGE: Umm-hmm.

Enron: Thanks Judy.

PGE: Umm-hmm.

Enron: Bye.

PGE: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 18:04

(This file involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 18:37

PGE:	I'm trying to call Enron here. 1- 800. (phone ringing)
Enron:	Enron, this is Jeremy.
PGE:	Yes Jeremy, this is Judy at Portland General.
Enron:	How's it going?
PGE:	Awful. You guys had a schedule where we were picking up energy from Water Power.
Enron:	Correct.
PGE:	And going to, let's see, back to you guys at John Day.
Enron:	Yeah, and we're using our transmission from John Day back to Malin.
PGE:	Right.
Enron:	Yeah.
PGE:	Now I've got that in through 1900. I haven't heard anything about 2000 yet.
Enron:	I just called you about 2000. I talked to Judy, honest to God about 40 minutes ago.
PGE:	Oh, Okay. So it is in there for 20? We just lost a plant, so things have been a scramble here.
Enron:	Okay. I'm not worried about it.
PGE:	Okay, we'll put it in. I'll talk to ya later.
Enron:	Bye.
PGE:	Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 18:55

PGE: Hello?

PGE-Trans: Hey home boy.

PGE: Yeah.

PGE-Trans: Need to have you help me straighten something out.

PGE: Well now Judy's gone. You watched her leave right?

PGE-Trans: Yeah, I've already tried with her … it didn't work.

PGE: Oh.

PGE-Trans: We're off in two places with BPA for the hour we're going into. One is on the south for 24 megawatts. I think that's the San Diego thing that they screwed up.

PGE: I don't think so.

PGE-Trans: Oh, you don't think.

PGE: Oh no, I think that might be the Enron thing?

PGE-Trans: They didn't do the last hour as far as I know.

PGE: They did.

PGE-Trans: Oh, did they?

PGE: Yeah, Judy called upstairs to Enron and they says, "oh yeah, it happens." So she made the change here.

PGE-Trans: Ahh. Okay, well that would be that. And then we're off 18 on the north.

PGE: 18.

PGE-Trans: And I don't know where the 18 would be. But yeah, nobody called me about the Enron thing, so I didn't make any changes.

PGE: Yeah. Okay, well yeah, it did happen apparently.

PGE-Trans: Okay.

PGE: Okay, well any loose ends just give me a buzz we'll see what we can work out.

Transcripts of Portland Scheduling Calls
04/15/00

PGE-Trans: Okay. Like I said, there's 18 on the north. So I'll take care of the 24 and see if you can find anything for the 18.

PGE: Okay. I'll keep looking then.

PGE-Trans: Okay.

PGE: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 19:00

PGE: Portland, this is Terry.

Enron: Terry, this is Jeremy over at Enron once again.

PGE: Yeah.

Enron: I'm calling because I just got off the phone with Felice over at well, you know how we're ... using LA's transmission from Malin? And he's saying that BPA hasn't been seeing on schedule that you guys have been putting in since hour ending 17^{th}. We have been talking to you hour by hour.

PGE: Yeah.

Enron: I'm not sure if you guys haven't been notifying your transmission guys, or if they haven't been calling BPA?

PGE: Yeah? I don't know what happened on Day's.

Enron: Okay, well can you check that out with BPA.

PGE: Yeah. Well it's 24 megawatts, right?

Enron: Yeah, it is. It's been going for a handful of hours.

PGE: Right.

Enron: Can you check on that and make sure everything is going all right?

PGE: Yeah, sure enough.

Enron: I'm not sure if you have to call them every hour and let them know.

PGE: Oh yeah. Well, if you call me every hour, I call them every hour.

Enron: Okay. Yeah, I don't know if Judy ... I think I was talking to Judy.

PGE: Yeah, she was on.

Enron: I'm not sure if she was doing that or not.

PGE: Yeah, Okay ...

Enron: Would you mind straightening that out with ...

PGE: Yeah, I'll try. Can you give me a good ... you got a 4-digit number I can call you at instead of this long 1-800 number?

Transcripts of Portland Scheduling Calls
04/15/00

Enron:	You can call me at 3827, that's my personal line.
PGE:	Okay, 3827.
Enron:	Yeah.
PGE:	Okay Jeremy.
Enron:	Thank you.
PGE:	Thank you.
Enron:	Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00-19:02

(This file involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 19:57

PGE: Portland, this is Terry.

Enron: Terry, this is Jeremy over at Enron.

PGE: Hey.

Enron: Once again, I'd like to do a 24.

PGE: Okay, we'll do it.

Enron: Hey, is everything cleared up with BPA now?

PGE: Yeah, so far as I know.

Enron: So you gave them a call?

PGE: Yeah I called them, I called the transmission guys upstairs, too, so, in fact we had a conference call.

Enron: That's great. Thanks a lot for taking care of that, Terry.

PGE: Yeah. You bet.

Enron: All right. Bye.

PGE: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 20:05

(This file involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15/00 – 200549

PGE-Trans: Portland, this is Floyd.

PGE: Hey Floyd, this is Terry.

PGE-Trans: Yeah.

PGE: Hey you know that Enron schedule of 24 megawatts?

PGE-Trans: Yeah.

PGE: Uh, that's, we played around with that several days ago.

PGE-Trans: Yeah.

PGE: And from what I understand, all BPA needed to know was this number that I got. I got a 6-digit number. I got this little yellow sticky I kept from a few days back.

PGE-Trans: Uh-huh.

PGE: 740768. And if you gave them that magic number they will know exactly where to put that 24 megawatts.

PGE-Trans: Okay. That'll help a lot.

PGE: Okay. But it's going to happen again for hour 22.

PGE-Trans: Okay.

PGE: Okay. Thank you.

PGE-Trans: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 20:39

(This file involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 21:11

PGE-Trans: Portland, this is Floyd.

PGE: Hey Floyd, this is Terry.

PGE-Trans: Yeah.

PGE: Hey, Enron scheduled again hour 24 megawatts and hour ending 23.

PGE-Trans: Okay.

PGE: Okay.

PGE-Trans: Okay.

PGE: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 21:43

PGE: Hello.

PGE-Trans: Okay, so I did need to call you this time. That Enron schedule.

PGE: Yeah.

PGE-Trans: It's going for this hour, right?

PGE: Yeah. Hour and 23.

PGE-Trans: And you've got it in? You sure?

PGE: Uh, both sides, yeah.

PGE-Trans: You sure? Cause I'm off by 24 on both sides with BPA, and I just looked, and my sides were both in, but ...

BPA: What is the Enron schedule?

PGE-Trans: This is from the ISO to PGE, and from PGE going to LAWP, yeah, it's the way it's set up, it's on both sides, don't you love it?

BPA: Yeah.

PGE-Trans: Well, I'm going to re-insert mine, because my computer is making weird faces at me, and see if that does any good, because it has been known to not take the numbers. Now I got Terry looking and I will give you a call back.

BPA: Okay.

PGE-Trans: Thanks.

BPA: Okay. Bye.

PGE-Trans: Terry, if you see anything, let me know. I'm just going to re-put it in on mine.

PGE: Yeah, I got it on one side, I just got to look on the other. Let's see if I can find the other.

PGE-Trans: Well, you know I rebooted the computer up here. So it's not impossible that that's my problem.

PGE: Yeah.

Transcripts of Portland Scheduling Calls
04/15/00

PGE-Trans: Cause sometimes when you do that it doesn't know that it's supposed to ... really, total numbers so.

PGE: Right.

PGE-Trans: Well, okay, I'm going to try to recalculate everything.

PGE: Now, let me see ... hour and 23, I got it in there, on both sides, yeah.

PGE-Trans: Okay, I'm just recalculating,

PGE: Okay.

PGE-Trans: I'll let you know what I find.

PGE: Thanks.

PGE-Trans: Thanks.

PGE: Bye.

PGE-Trans: Bye.

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 21:55

(This file involves separate transactions)

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 22:13

PGE: Hello.

Enron: Hello, this is Jeremy over at Enron.

PGE: Hey, what's up?

Enron: Not much. This is Terry?

PGE: Yeah.

Enron: Hey. I'm sorry I'm a bit late but I want to do that repeat for 24.

PGE: Okay, we'll do it one more time.

Enron: All right, thanks buddy.

PGE: Hey, you bet.

Next call:

PGE-Trans: This is Floyd.

PGE: Hey, Floyd, it's Terry.

PGE-Trans: What?

PGE: You know the Enron Schedule.

PGE-Trans: Yeah.

PGE: 24 megawatts, you want to do that again for an hour and 24.

PGE-Trans: Okay.

PGE: Thank you.

PGE-Trans: Bye.

PGE: Bye-bye.

(Next call involves separate transaction)

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 22:21

04/15 – 22:43

04/15 – 23:14

(These files involve separate transactions)

Transcripts of Portland Scheduling Calls
04/15/00

04/15 – 23:34

Enron: Enron, this is Jeremy.

PGE: Hey Jeremy, this is Terry.

Enron: Hey, what's going on.

PGE: Hey, are we doing the 24 again or what?

Enron: For, hour ending …

PGE: One.

Enron: No, no.

PGE: Okay, it's done with, I guess.

Enron: Yeah, well, we might try to bring it back in hour ending 3.

PGE: Okay.

Enron: Just for now, for a couple of hours. …

PGE: Just checking.

Enron: Okay. Bye.

PGE: Bye.

Next call:

PGE: Umm ... Enron, 24 megawatts, not happening for a couple of hours.

PGE-Trans: Okay, and we're not cutting anything to the CPX or anything, huh? In other words, you don't have to bother me?

PGE: Well, I have to bother BPA.

(Side conversation)

PGE-Trans: Okay.

PGE: Okay. Bye.

→ 6/6/00

Transcript of Scheduler Telephone Conversation
04/06/00

04/00.wav (No indication of time, but first relevant call for 04/06/00)

(First call involves separate transaction)

Committee on Governmental Affairs
EXHIBIT #A-48

Next Call:

Washington Water Power (WWP): Water Power, this is Sue.

Portland General Electric (PGE): Sue, this is Terry ...

WWP: Hi there!

PGE: Do you know anything about an account that we need to talk about, for 25 megawatts, for hour ending 10?

WWP: Well, umm ... yeah ... what it is, is that I guess we are going to do a sleeve, but with Enron.

PGE: A what?

WWP: A sleeve.

PGE: I've never heard of that term.

WWP: Okay. Well, basically it's a buy and resale.

PGE: Okay.

WWP: Umm... they didn't call you on it? I guess they can't, huh. Okay, what they, what it is, is I'm going to buy, here's the path, 25 megawatts of generating at the ISO.

PGE: Correct.

WWP: It's going to Enron, then to me, then to you, at Malin, then I'm picking it back up from you at Malin, and it's going back to Enron.

PGE: Okay, Enron, to Water Power, to me ...

WWP: Then back to me ...

PGE: Now this is one account.

WWP: Right.

Transcript of Scheduler Telephone Conversation
04/06/00

PGE:	Okay, so it's from Enron to Water Power to me?
WWP:	Right. And it's basically an "in" and an "out."
PGE:	Okay. And it's 25 megawatts?
WWP:	Right.
PGE:	And two ...
WWP:	Two back to Enron.
PGE:	Okay, at John Day.
WWP:	Right, at Malin.
PGE:	... Yeah, well, I was just given a yellow sticky, with the ... two accounts, the two accounts, the [Bonneville Power ("BPA")] and the Enron at John Day. So, I can do that ...
WWP:	Well, it wouldn't be, because it would actually be to me.
PGE:	To you.
WWP:	Yeah. Because its the ISO – Enron – me – you.
PGE:	Okay, wait a second. The first account is to me. And that path is ISO, Enron.
WWP:	Uh-huh.
PGE:	ISO, Enron, you folks to me. Okay. And the other account. The To account.
WWP:	The To account is going to be you … me.
PGE:	PGE, Water Power.
WWP:	And then Enron. So you're not next to Enron. Does that make sense?
PGE:	Sort of.
WWP:	I guess we need to find the sink on it, hah.
PGE:	Well.

Transcript of Scheduler Telephone Conversation
04/06/00

WWP: That would be a good idea, huh?

PGE: I think so.

WWP: Okay, let me call you back.

PGE: Can Enron be the sink?

WWP: Pardon?

PGE: Can Enron be the sink?

WWP: I don't think they can.

PGE: Cause I've got an account that just says To BPA Enron at John Day.

WWP: But I think it's all at Malin.

PGE: If you could find out.

WWP: Okay let me call you right back.

PGE: Okay.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_8:27

PGE: Hello.

PGE-Trans: What are you doing here?

PGE: Oh, slumming.

PGE-Trans: I guess ... are you working or is he?

PGE: Oh, I always work when I am here. Why else would I be here?

PGE-Trans: You handled your buddy Bill Casey's [expletive].

PGE: Well, speak to me!

PGE-Trans: They are doing that selling power to Enron across BPA going down to CA crap again.

PGE: Well, I don't know about again, I thought it was a new deal ...

PGE-Trans: Yeah, but they did that before, remember, and there's all those extra accounts, and then you guys have to make sure you do whatever extra input you have to do and you also have to tell BPA cause you're actually importing across BPA line.

PGE: Okay.

PGE-Trans: And I have to tell BPA about it going south.

PGE: Oh.

PGE-Trans: I figured I would warn you so you could make sure that whatever number they had that ... I go ... from BPA PG firm account thing ... You've got 63 in there as a pre-schedule.

PGE: Well ...

PGE-Trans: I assume that ...

PGE: Bill Casey gave me a yellow sticky, he says there are two accounts to be concerned with. One is from the ISO Water Power AC, okay.

PGE-Trans: Hmm ... the ISO water power? I don't know anything about that one ...

PGE: Okay, that's 'cause it's an "in" and an "out" ...

Transcript of Scheduler Telephone Conversation
04/06/00

PGE-Trans: Okay.

PGE: And the other account is to BPA, Enron, and John Day. And he told me I have to call it in to BPA and give them the specific account number that they go by.

PGE-Trans: Yeah, yeah ... that's what I figure, there is some account there, and I put it in. I have a from BPA PGE account, and then I have to put it in the south end too, so that it balances out...

PGE: Sure.

PGE-Trans: It's bizarreness.

PGE: Okay.

PGE-Trans: So if you get yours right and I get mine right, then hopefully everything will agree. But God only knows.

PGE: So, if this is to BPA, do I call BPA or do I call you?

PGE-Trans: Well, you're going in to the BPA system, so I would call BPA on that one.

PGE: But, but... okay. Water Power is going to call me back too, 'cause they were thinking that it was going to be at Malin.

PGE-Trans: Yeah. See, I don't know about this Water Power account, the only thing I know about them is ... well you don't even know about that, it's the transmission schedule.

PGE: Okay.

PGE-Trans: Okay.

PGE: All right, thanks. Bye.

PGE-Trans: Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_8:38

PGE: Hello.

PGE-Trans: Okay. So, did you do something with that Washington Power account? Because we're off by 25 with the ISO er, with BPA.

PGE: Yeah, I called BPA about it.

PGE-Trans: Now is that 25 coming north from Washington Water Power? Is that what that is?

PGE: Well, she was going to call me back.

PGE-Trans: Because that's kinda what it sounds like. Because they actually gotta be 25 headed south.

PGE: Right. 25 headed south. And I called that into BPA. And the other account is apparently from the ISO but we're picking it up from Water Power. So that's kinda, it's already up here and we're getting it from Water Power, you know?

PGE-Trans: Yeah, yeah. You're sending another 25 south for us to Water. Where is the other 25 going?

PGE: The account is just to John Day. To BPA … Enron John Day account. That's the account I put it in. And all I did is call BPA and I gave them their number 740768.

PGE-Trans: Yeah, and I gave them the PGE going to the ISO, which is actually the Enron account because that's where it eventually winds up. But we're still 25MW short somewhere.

PGE: Hmm. No balance, huh?

PGE-Trans: Well I balance. I balance across the system but somehow or another there's a 25 account someplace. That's what I said, this is a piece of crap. I can't believe they're doing it to us again. They never set up the accounts right. There's, like, 18 accounts that this affects. And if you don't put it in the right ones the right way. Now, see now, my numbers just changed, though.

PGE: Oh they did?

PGE-Trans: Yeah, I had a 6 before and now I have a 31 left over.

Transcript of Scheduler Telephone Conversation
04/06/00

PGE: Okay. That's your 25.

PGE-Trans: Came back someplace. Where did it come back from?

PGE: I touched nothing.

PGE-Trans: Well, I can tell because I can look at the real time log. What was the last 25 that ... Let's see, and this is...what time is this anyway? Hour ending 10 ... Bill Casey.

PGE: Bill Casey!

PGE-Trans: He's putting something in. He put in WP's 25 and didn't tell anybody about it.

PGE: Well, he's just standing over my shoulder.

PGE-Trans: Well, why don't you tell him that I have BPA on the line and we're off by 25 and I need to find out why.

PGE: He went back over to his desk. Let me talk to him and can I call BPA?

PGE-Trans: Yeah, you can call BPA.

PGE: And I'll call you as well.

PGE-Trans: Thank you, sir. Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_08:41

PGE: This is the word … the account names, if you look at those, are memo accounts, that Bill had to put some information in.

PGE-Trans: Okay.

PGE: So it shouldn't affect the control number at all.

PGE-Trans: Well, either that did it, or your entry at 8:24 for a purchase from 0 to minus 25 did it, because when I put in my numbers I refreshed.

PGE: Okay, well...

PGE-Trans: I had 6 left on the southbound.

PGE: I had the 25 that I purchased and the 25 that I sold. But on this other real time screen that we've got nowadays, it took forever for that to show. So that may have been why things were kind of stumbling for you.

PGE-Trans: Well, when I put them in they all came up right.

PGE: Okay.

PGE-Trans: Yeah, the number was right when I finished my entries.

PGE: Yeah.

PGE-Trans: It's now 25 higher.

PGE: Okay.

PGE-Trans: I finished my entries at 0841.

PGE: Okay.

PGE-Trans: And um … I don't understand, because that's what it says, the last entry was me. Your entry was made at 0824 and it wasn't taken until after mine was done evidently.

PGE: Yeah, I don't know why.

PGE-Trans: And that's a little bit on the bizarre side. Well, anyway, the account you put in, for some reason, it took 25 off the south end.

PGE: Hmm … the to BPA/Enron … John Day?

Transcript of Scheduler Telephone Conversation
04/06/00

PGE-Trans: I don't know!

PGE: You don't know?

PGE-Trans: Have you got the real time log up? Can you look at the real time log?

PGE: Well ...

PGE-Trans: You can't see my entries, though, can you?

PGE: Yeah, I think I can. Well no, not the transmission ... no, maybe I can't. Umm, well, I've got some accounts, it doesn't say who to, though, I've got about 6 different accounts that show me ... you, real time.

PGE-Trans: Yeah.

PGE: Priority 10, 0 to 25, positive negatives, okay.

PGE-Trans: And when I finished those, I had, like I said, 6 left on the directs. And now I've got 31 left on the directs, which is a change of 25.

PGE: Correct.

PGE-Trans: And the only other 25 is your purchase, but it says from CAISO -- Washington Water ...

PGE: Correct.

PGE-Trans: So it's actually coming from the ISO.

PGE: Well, yeah, but ...

PGE-Trans: But it is on transmission, it is showing on that account. That account tells my transmission you're bringing 25 megawatts to Portland from the ISO.

PGE: Oh it does?

PGE-Trans: Yeah.

PGE: Yeah. So it's telling me, that I have to tell BPA that you're bringing 25 up from the south ... Washington Water Power.

PGE-Trans: Okay, let me have a talk about the bill and I'll get back to you.

PGE: Okay bye.

Transcript of Scheduler Telephone Conversation
04/06/00

PGE-Trans: Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_08:44

(Side conversation)

PGE:	Hey, uh … I'm trying to get up to speed, this account to us, this account is from the ISO.
PGE-Trans:	Okay.
PGE:	So hopefully, this will help.
PGE-Trans:	So just call it in, and that will reverse it, and I will be good.
PGE:	Okay, do I need to ...
PGE-Trans:	Okay, I'll call it in.
PGE:	Okay.
PGE-Trans:	Thank you, sir.
PGE:	Oh, the ISO is on the line, we're trying to square them away too.
PGE-Trans:	Okay.
PGE:	Okay. Bye.
PGE-Trans:	Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_09:02

PGE:	Hello.
Enron:	Yes, who am I speaking with?
PGE:	Terry Finley.
Enron:	Hey Terry, John Forney.
PGE:	Hey John.
Enron:	How you doing?
PGE:	Good.
Enron:	We did a deal with you guys for hour ending 10.
PGE:	Yeah, I guess.
Enron:	Yeah, 25 megawatts, and it's John Day to Malin.
PGE:	Correct.
Enron:	And we for hour ending 11 would like to do a duplicate of that.
PGE:	Okay. Same old same old.
Enron:	Yeah.
PGE:	Okay, we'll get it on.
Enron:	I talked to Lee in Portland transmission. Do I need to not talk to him at all?
PGE:	She is the pre-schedule transmission person ... the person ... is Floyd.
Enron:	Okay.
PGE:	Floyd is probably the guy you talk to.
Enron:	Okay, I told him, you know, because I talked to him about this, I told him that we were going to do it again, he said I needed to talk to you.
PGE:	Right, if you give me a buzz, I can put it in the right accounts, and I can call him and it's a done deal.

Transcript of Scheduler Telephone Conversation
04/06/00

Enron:	Okay, so I don't need to talk to him at all?
PGE:	No.
Enron:	Okay, great.
PGE:	Good.
Enron:	Thank you Terry.
PGE:	You bet. See you.
Enron:	See you.

<u>Next call:</u>

WWP:	Portland ... this is Sue.
PGE:	Sue this is Terry ...
WWP:	Hi there!
PGE:	Enron called a moment ago.
WWP:	Yeah?
PGE:	And ...
WWP:	They want to do it again.
PGE:	And they want to do it again. So I guess we'll put it in.
WWP:	Okay.

(Remainder of call involves separate transaction)

Transcript of Scheduler Telephone Conversation
04/06/00

040600_09:03

PGE: Portland. This is Terry.

PGE-Trans: Okay I'll bite. We had this straightened out. We had a 718. And now, the number changed again, and I got a 693 and I'm out with BPA again. And its all a part of this crap that Bill is doing I think. But I don't know why. I didn't make any other changes on this. My number has changed twice on my transmission since I fixed by somebody else dealing with it. So, somebody is putting their fingers in places they shouldn't ought to be and I don't know how to fix it because I don't know what they're doing.

PGE: Okay.

PGE-Trans: So we're out again with BPA and I haven't touched anything. So find out what we've got done since we agreed on a number at a quarter 'til, or whatever, and tell them to undo it.

PGE: Okay. I'll have him check his, check the activity he engages himself in.

PGE-Trans: The only thing I did is at 850 where Bill put in to Washington Water Power Sale MC Memo.

PGE: Yeah. He did 4 memo accounts.

PGE-Trans: Right. But, that shouldn't affect the south end but my direction changed again.

PGE: He was still checking on flags and I think he's still checking on flags.

PGE-Trans: Well, somebody did something and I went from originally a 718, remember we talked? The 718 and now its a 693. So, where I had, originally I had 6MW left and I told people that I didn't have transmission to sell them because I only had 6MW left. And I still got 31 showing because I haven't updated my screen and now I'm updating my screen and now I've got 56 available. So something keeps changing and I lied to everybody when I posted this. They all wondered why I didn't sell them my non-firm. So something needs to quit getting changed.

PGE: Okay.

PGE-Trans: Thank you, sir.

PGE: Okay. Bye.

PGE-Trans: Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

(Next call involves separate transaction)

Transcript of Scheduler Telephone Conversation
04/06/00

040600_907

(First call involves separate transaction)

Next Call:

PGE-Trans: Portland. This is Robert.

PGE: Robert, its Terry.

PGE-Trans: You want to talk to Floyd?

PGE: No. I'll do it anyway. I'll wait.

PGE-Trans: You want to talk to me?

PGE: I can talk to you.

PGE-Trans: Because he's talking to Matt right now.

PGE: Okay. Well, yeah, this has to do with that fiasco. The same thing that happened last hour ... the buy, resell with the ISO is happening again ... 25MW.

PGE-Trans: Okay, for the next hour.

PGE: Yeah. Okay.

PGE-Trans: Okay.

PGE: Okay.

PGE-Trans: I'll let him know.

PGE: Thank you. Bye.

PGE-Trans: Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_09:36 (same as 040600_9:39)

PGE: Hello.

PGE-Trans: Hey. We're doing that 25 coming up from the south again.

PGE: Oh yeah. I told Robert and Bill Casey came over and said we should be all squared away.

PGE-Trans: Okay, what we're doing is that … he had an account that to be activated in the wrong flag. Is basically what it was. I had to get Matt to come in.

(Side conversation)

PGE-Trans: Well, let me go take care of stuff and I'll talk to you in a bit.

PGE: Okay. Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_10:21

PGE: Hello.

PGE-Trans: Hey, its me.

PGE: Okay.

PGE-Trans: Told ya everything is coming?

PGE: Yeah.

PGE-Trans: Well?

PGE: Boy ... you're early?

PGE-Trans: No, I just knew that since Enron was doing this crap that you were probably doing weird stuff too.

PGE: Yeah, now he told me that this should be the last hour.

PGE-Trans: Yeah.

PGE: Now, whatever that means. But yeah, we're doing it again.

PGE-Trans: So, that also means you're bringing the 25 up from Washington Water Power again.

PGE: Yes, sir.

PGE-Trans: And all that crap.

PGE: Same old same old.

PGE-Trans: That's what I thought.

PGE: Yup.

PGE-Trans: Just figured I'd check.

PGE: Well, no problem.

PGE-Trans: Anything else fun?

PGE: Umm ...

Transcript of Scheduler Telephone Conversation
04/06/00

PGE-Trans: I told you it was Bill that was messing us up. I told you that.

PGE: Well, I know, and I knew ...

PGE-Trans: Yeah, I know, I just didn't know how.

PGE: Yeah [laughter].

PGE-Trans: I had to get [indecipherable] of here. Matt figured it out, finally for me.

PGE: Okay. Well, good.

PGE-Trans: Okay.

PGE: Okay.

PGE-Trans: Thank you.

PGE: Bye.

PGE-Trans: Bye.

(Next call involves a separate transaction)

Transcript of Scheduler Telephone Conversation
04/06/00

040600_13:58

PGE:	Hello.
Enron:	Hello this is Mike at Enron.
PGE:	Hey Mike.
Enron:	Is this PGE?
PGE:	Yeah.
Enron:	What's going on man?
PGE:	Oh a little of this, a little of that.
Enron:	Yeah exactly, I was wondering if we could do that buy-resell again for next hour.
PGE:	Oh no, you want to do it again?
Enron:	Yeah.
PGE:	Okay what hour do you need, sixteen?
Enron:	Yeah, 40 MWs this time.
PGE:	Oh, Okay.
Enron:	And then we are probably going to go back to 25, but ...
PGE:	But this hour, hour 16, we'll do a 40.
Enron:	A 4-0.
PGE:	Okay.
Enron:	Thank you, sir.
PGE:	Thank you.
Enron:	See ya.
PGE:	Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_14:04

(First call involves separate transaction)

Next Call:

WWP: Water Power this is Sue.

PGE: Sue this is Terry in Portland.

WWP: Hi there.

PGE: Hey do you need anything at all?

WWP: I am actually sitting just fat here.

PGE: Oh, Okay.

(Side conversation)

PGE: Hey did you get a call from Enron?

WWP: Aahh, yeah I did for 40.

PGE: For 40 huh ... hour number 16.

WWP: I got it.

PGE: Okay I guess the same situation as a few hours back.

WWP: Yeah that is what it sounds like.

PGE: Yeah okay, we'll do it.

WWP: Thanks Terry.

PGE: Bye.

WWP: Bye.

(Next Call involves separate transaction)

Transcript of Scheduler Telephone Conversation
04/06/00

040600_14:06

(First call involves separate transaction)

Next Call:

PGE-Trans: Portland, this is Robert.

PGE: Robert, this is Terry.

PGE-Trans: Yeah.

PGE: Hey, were you in on that Enron stuff that we had going a while ago, a couple of hours back?

PGE-Trans: Floyd's been doing it.

PGE: Okay.

PGE-Trans: They called and said they wanted to do another 40.

PGE: Yeah.

PGE-Trans: Yeah he called for 16.

PGE: Yes, sir.

PGE-Trans: Yes.

PGE: Okay.

PGE-Trans: We got that.

PGE: Okay well good. Well thank you. Bye.

PGE-Trans: Bye.

(Next call consists of side conversation)

Transcript of Scheduler Telephone Conversation
04/06/00

040600_14:17

BPA: BPA Transmission this is Mike [Newshum] [phonetic].

PGE: Mike, this is Terry in Portland.

BPA: Yeah Terry.

PGE: Hey, I've got an account…, I've got two accounts I need to talk to you about for hour ending 16.

BPA: Okay.

(Discussion of separate transaction)

PGE: And the other account … were you around when … did we talk at all about this thing with Enron and Water Power?

BPA: [laughs]

PGE: [laughs]

BPA: That's what I think of that [laughs].

PGE: Got it.

BPA: It's not that bad. Well, I don't know. Maybe this is something different.

PGE: No. It's the same thing.

BPA: Is it?

PGE: Yeah.

BPA: 25?

PGE: No, it's going to be 40 for hour 16.

BPA: How did we … where did we put it last time?

PGE: Oh, let me see. I think I can give you a number that you guys go by. It's a six digit number.

BPA: 740 …

PGE: That's half of it.

Transcript of Scheduler Telephone Conversation
04/06/00

BPA: ... 768. It has, like, 68s in it?

PGE: Umm, I think so.

BPA: Yeah, it has 68s in it. We did ... we increased it by it looks like 20 ...

PGE: 25?

BPA: 25 by N.

PGE: 25 by 3 times?

BPA: Umm, 25 in, where was it, wait a minute. 25 in 10 and, oh, that's the only hour.

PGE: No, there were 3 hours so far.

BPA: Hmm. I wonder what it is about this account that's so peculiar?

PGE: I don't know.

BPA: Okay. All right, I know which hours it is that we need to do that in.

PGE: Okay for hour ...

BPA: Oh, it's 740768.

PGE: 740768.

BPA: I found the paper that I wrote it on.

PGE: That's the one. This is a most bizarre account.

BPA: Yeah.

PGE: We're looking at this and its mate.

BPA: Somebody's spent some time trying to come up with it I guess.

PGE: Weird looking stuff.

BPA: Yeah.

PGE: It's not at all what we're used to seeing.

Transcript of Scheduler Telephone Conversation
04/06/00

BPA: Yeah.

PGE: Okay. 740768. Portland. Okay. Okay. I see that. All righty.

BPA: Okay.

PGE: And what do you want to do on 16?

BPA: 40.

PGE: At 40. So it will be a 1-0-8. Okay.

BPA: And that's it for now.

PGE: All righty.

BPA: Okay.

PGE: Thank you.

BPA: Thank you.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_14:55

(First call involves separate transaction)

Next Call:

PGE: Portland, this is Terry.

Enron: Hey, Terry. Mike at Enron.

PGE: Hey.

Enron: What's going on.

PGE: One hour closer to getting out of here.

Enron: Yeah, exactly. Umm, 25 next hour.

PGE: Okay. I'll put it in.

Enron: I'll run that by resale.

PGE: Okay.

Enron: Thank you.

PGE: Thank you.

Enron: Bye.

PGE: Bye.

(Next Call involves separate transaction)

Transcript of Scheduler Telephone Conversation
04/06/00

040600_15:23

(First call involves separate transaction)

Next Call:

PGE-Trans:	Portland, this is Floyd.
PGE:	Hey, Floyd. It's Terry.
PGE-Trans:	What?
PGE:	Hey, Enron.
PGE-Trans:	I don't want to hear about Enron.
PGE:	25 Megawatts. Hour ending 17.
PGE-Trans:	I don't want to hear about Enron. I don't care about Enron. Somebody burn Enron. Enron is worthless.
PGE:	You'd better get your money out first.
PGE-Trans:	No, no. I don't have to get my money out. Nothing.
PGE:	Oh? Okay.
PGE-Trans:	I'd have to sell the stock.
PGE:	Oh, well. Get your options going.

(Side conversation involving taxes)

PGE-Trans:	Okay, 25. I got you.
PGE:	Thank you.
PGE-Trans:	Bye.
PGE:	Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_16:00

PGE:	Hello.
Enron:	Hello, is Terry there?
PGE:	Yeah.
Enron:	Terry, Mike at Enron.
PGE:	Hey Mike.
Enron:	How about next hour 25 MWs.
PGE:	Let's do it again.
Enron:	Thank you.
PGE:	Okay.
Enron:	Later.
PGE:	Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_16:06

PGE-Trans: Portland. This is Blake.

PGE: Blake, it's Terry.

PGE-Trans: Terry.

PGE: Enron. Hour ending 18, I guess is what it is, yeah 18, is 25. And that's it.

PGE-Trans: I'll sure be glad when we're sold and they can't pull this [expletive] anymore.

PGE: Me too.

(Side conversation)

Next Call:

BPA: BPA Transmission. Mike [Newshum] [phonetic].

PGE: Hey Mike. This is Terry in Portland.

(Side conversation)

BPA: Okay. What do you got for me?

PGE: Well, you know that Enron schedule ... of 25 megawatts ... that one we've been playing with a few hours today?

BPA: I'm trying to wipe my hands and get it off my feet. Yes, okay, and about the BPA schedule. 7-5 way back there to Portland. I don't know, we've got something wrong with our accounts on that one and I don't know what the story is. Okay, you didn't do anything with it in 17, right? Or you did 25?

PGE: Yeah, 25.

BPA: Increase 25?

PGE: Oh, well, it was 25, it went to 25. Well, I guess it was a total increase. 40 for 60, 25 for 17.

BPA: It doesn't seem to matter what I do with the schedule. It just doesn't change anything.

Transcript of Scheduler Telephone Conversation
04/06/00

PGE: Its all wrong. Its always wrong.

BPA: What are you up ... What is it for 18?

PGE: 1800 is 25.

BPA: 25.

PGE: Yeah.

BPA: 6-8 plus 2-5 plus 93. And what was it for 17, 25?

PGE: 25, for 25, yeah.

BPA: 93, okay. I'm going to go make those changes and see if that affects our net that we have with you guys. Because I'm having a feeling something is going awry, badly awry ...

PGE: Oh, I hope not.

BPA: ... and its making me real nervous. Okay.

PGE: Okay.

BPA: Thank you.

PGE: Thank you.

BPA: Bye.

PGE: Bye.

(Next call involves separate transaction)

Transcript of Scheduler Telephone Conversation
04/06/00

040600_16:16

PGE: Portland. This is Terry.

Enron: Terry. Mike at Enron.

PGE: Hey.

Enron: Hey, for 1800. My resale has to go to zero.

PGE: You're kidding.

Enron: I'm not joking.

PGE: Okay. I'll take it out.

Enron: The ISO just totally worked me.

PGE: Okay.

Enron: Thanks.

PGE: Bye.

Next Call:

PGE: Portland. This is Terry.

WWP: Hi Terry. Sue at Water Power.

PGE: Hi Sue.

WWP: Hey I just got a call from Enron.

PGE: Me too.

WWP: You too. Great. We're happy.

PGE: Okay.

WWP: Thanks.

PGE: Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

Next Call:

PGE-Trans: Portland. This is Floyd.

PGE: Floyd, its Terry. Enron Schedule … hour ending 18 … 25 megawatts goes to zero.

PGE-Trans: So don't do the 25 megawatts.

PGE: Yeah, good thing you're dragging your feet.

PGE-Trans: Ah, okay.

PGE: Thank you. Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_16:17

BPA: BPA transmission. Mike [Newshurn] [phonetic].

PGE: Hey Mike. This is Terry here in Portland.

BPA: Yeah, Terry.

PGE: Hey you know that BPA Schedule? I hate to mention this. They want to go to zero for hour 18. At 25 they said it's not going to go.

BPA: That's good. They can do that. I can deal with that. At least I will make every effort to deal with that.

PGE: I'm sure you'll be successful.

BPA: I'll go back to 68.

PGE: Yeah.

BPA: Okay.

PGE: Thanks.

BPA: Thank you.

PGE: Bye.

BPA: Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_16:29

PGE: Hello.

PGE-Trans: Hello. It's me.

PGE: Okay.

PGE-Trans: So, first you did the Enron and then you undid the Enron. Did we do anything else besides this? I have 25 going south they don't. Did you put a 25 some place that you didn't take out on Enron maybe or something?

PGE: No, I don't think so. I think I got four different accounts than they do. I think I got them all. I'll keep pecking.

PGE-Trans: Yeah, cause we got 25 more than they do. They're on line with us by the way.

PGE: Yeah.

PGE-Trans: Yeah, okay. Let me check and I'll call you both.

PGE: Okay.

PGE-Trans: Okay.

PGE: Thanks.

PGE-Trans: Bye.

PGE: Bye.

<u>Next Call:</u>

PGE-Trans: Portland. This is Floyd.

PGE: I found it.

PGE-Trans: I saw it change.

PGE: Okay. Thanks.

PGE-Trans: Thanks.

Transcript of Scheduler Telephone Conversation
04/06/00

Next Call:

BPA: BPA transmission. Kathy.

PGE: Kathy. It's Terry at Portland.

BPA: Hey.

PGE: I found it.

BPA: Oh good.

PGE: I got it out.

BPA: Thanks.

PGE: Okay. Thank you.

BPA: Bye.

PGE: Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_17:02

PGE: Portland. This is Terry.

Enron: Terry. Les at Enron.

PGE: Hey.

Enron: Hey. You guys been doin' a buy resell for us?

PGE: Well, we did until last hour and then it was cut.

Enron: Well for hour 19, we would like to do it again. 40 MW.

PGE: 40, huh?

Enron: Yeah. For hour ending 19.

PGE: Okay.

Enron: Anything else you need from me?

PGE: Just for you to call Water Power.

Enron: I believe we've done that and I've already called Portland Trans.

PGE: Okay.

Enron: Thank you.

PGE: Thank you.

Enron: Bye.

PGE: Bye.

Next Call:

WWP: Water Power. This is Sue.

PGE: Sue, its Terry.

WWP: Hi there.

PGE: Hey, Enron again ...

Transcript of Scheduler Telephone Conversation
04/06/00

WWP: Yeah.

PGE: 40.

WWP: Yeah, got it.

PGE: Okay.

WWP: Bye.

PGE: Bye.

(Next call disconnected)

Transcript of Scheduler Telephone Conversation
04/06/00

040600_17:04

PGE: Portland. This is Terry.

BPA: Yeah, Terry. This is Mike at BPA. Do you have a minute?

PGE: Sure.

BPA: Okay. I want to make sure that I got all those Portland to John Day to Portland whatsidoosits right.

PGE: Okay.

BPA: In hour ending 10 I had a 93. It was a 25 increase.

PGE: Yeah, let me get to that one account.

BPA: Let me get back there too because I think I can ... I had some of them and I wasn't quite sure what to do with those stupid things. I had never run into it before. Okay, I had 10, I had a 93 ... a 25 increase. Did you have anything for 11?

PGE: Yeah. 10 was a 93 increase to 25. 11 was a 93 increase to 25. 12 was the same thing. Then no action for hour ending 13, 14 and 15. 16 was 108. That was an increase of 40. 17 was a 2-5. 18 was a 2-5. Then they cut it.

BPA: Then they cut it back to 68.

PGE: Yeah. Already 19, while I got you on the line, we're talking about the same thing here, it's a 4-0.

BPA: 108 again.

PGE: I hope they leave it alone.

BPA: I finally understand what this is all about. You're buying transmission from your transmission folk.

PGE: Yeah.

BPA: From Mid-C.

PGE: Right.

BPA: Oh, okay. All right, well that's interesting. That's interesting.

Transcript of Scheduler Telephone Conversation
04/06/00

PGE: Yeah, they haven't explained to me what the heck is going I just put in these numbers.

BPA: Yeah, well, our marketing side has been having to do that for quite awhile now and boy, does it get complicated.

PGE: Oh yeah. Yeah, I have four accounts I have to deal with each time they call, you know.

BPA: Yeah, stupid. This is also reflected on back side under the directs.

PGE: Yeah. And that's something that Floyd would call into you guys.

BPA: Yeah, okay. I just want to make sure that it all divides and adds and is correct because it doesn't affect the controller because its an "in" and an "out." Still, it should all be the same.

PGE: That's right.

BPA: Okay. Thank you.

PGE: Thank you.

BPA: Bye.

PGE: Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_17:12

PGE-Trans:	Portland, this is Floyd.
PGE:	Portland. Terry. That ISO ... Enron schedule ...
PGE-Trans:	uh-huh ...
PGE:	40 hour ending 19.
PGE-Trans:	I know.
PGE:	Oh. You already got a call about that. I gotta call you anyway.
PGE-Trans:	But, yeah, you gotta call me anyway to make sure, er, so I can make sure that you know about it. And just so you know, Enron, er Enron, BPA was just calling me again about that. They're still trying to figure out why it comes in one place and goes out the other. They couldn't figure out the 25 going south until I told them that the ISO to PGE going north is the other half of that. So there's still confusion on their end. We've been matching but I don't think we're very happy with it. So if you could give them a call they're trying to figure out what the [expletive] is going on.
PGE:	Yeah, well Mike over there at BPA called me and we talked about it a bit.
PGE-Trans:	Yeah, Yeah.
PGE:	And I just made sure that everything's square.
PGE-Trans:	That's what I mean. He called me just a minute ago to do the same thing. You know, to figure this out. And I said this is where I'd put it. But, you know, my accounts aren't the same as yours.
PGE:	That's right. You know. You try to accommodate them as best you can.
PGE-Trans:	Yeah, I can't tell you how to run your system, Mike, I can only tell you how it works in mine.
PGE:	You know where I'd put it if I were you.
PGE-Trans:	Okay.
PGE:	Okay.
PGE-Trans:	Bye.

Transcript of Scheduler Telephone Conversation
04/06/00

040600_17:29

PGE: Portland. This is Terry.

PGE-Trans: Hey I got BPA here with me. We're off 40 on both sides.

PGE: 40?

PGE-Trans: Yeah, which would be what Enron was doing. And I thought I'd check and see if you had all those extra accounts if maybe there was a 40.

PGE: I got a 40 going to er coming from [Shtomy].

PGE-Trans: Oh. I didn't know that.

BPA: From [Shtomy] [phonetic] to PGE?

PGE: Yes ma'am.

BPA: If we got it in.

PGE-Trans: Ok. See actually, they have 40 more than we do on the north. So we would either be sending 40 out that they don't have.

PGE: Ok. I'll check the four different the accounts and I'll call you both.

PGE-Trans: And I've also got it on the south. They've got 676 and I got a 636.

PGE: Okay.

PGE-Trans: Okay. Thank you, sir.

PGE: Thank you.

PGE-Trans: Bye.

PGE: Bye.

Committee on Governmental Affairs
EXHIBIT #A-49

UNITED STATES OF AMERICA 100 FERC ¶ 61,186
FEDERAL ENERGY REGULATORY COMMISSION

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

Portland General Electric Company
Enron Power Marketing, Inc.

Docket No. EL02-114-000

ORDER INITIATING INVESTIGATION, AND ESTABLISHING HEARING PROCEDURES AND REFUND EFFECTIVE DATE

(Issued August 13, 2002)

1. In this order we are initiating an investigation into instances of possible misconduct by two Enron Corporation affiliates: Enron Power Marketing, Inc. (EPMI) and Portland General Electric Company (Portland) (collectively, Enron) to determine whether the misconduct occurred and, if so, to determine remedies, including possibly refunds and/or revocation of Portland's and/or Enron's market-based rate authority.

2. As discussed below, we will set the possible misconduct for hearing and establish a refund effective date under section 206 of the Federal Power Act (FPA), 16 U.S.C. § 824e (1994), to provide for refunds should the hearing indicate that they are warranted.

Background

3. On February 13, 2002, the Commission directed a Staff fact-finding investigation into whether any entity 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.[1]

4. On May 8, 2002, in accord with the Commission's directive, Commission Staff issued a data request concerning various trading strategies of sellers of wholesale

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[1]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, 98 FERC 61,165 (2002) (February 13 Order).

20020813-3045 Received by FERC OSEC 08/13/2002 in Docket#: EL02-114-000

electricity and/or ancillary services in the United States portion of the Western System Coordinating Council during 2000-2001. Among the sellers to whom the data request was sent are public utilities who were granted market-based rate authority by this Commission based on a finding that they lacked market power and there was no evidence of affiliate abuse or reciprocal dealing.

5. On June 4, 2002, the Commission issued an order[2] finding that Portland and others had failed to cooperate with the Commission investigation and ordered those companies to show cause why their authority to charge market-based rates should not be revoked as a result of their failure to comply with the Commission-ordered investigation.

Discussion

6. In a Commission Staff initial report, being publicly released concurrently with this order,[3] Commission Staff states that it has obtained preliminary evidence of possible violations by Portland and Enron (specifically, EPMI) of their codes of conduct and the Commission's standards of conduct. Codes of conduct govern, among other things, a power marketer's relationship with its traditional public utility affiliates, including limitations on its ability to sell power at market-based rates to its affiliate with captive customers and the pricing of sales of non-power goods and services between the affiliates. In addition, any sharing of information between Portland and Enron must be simultaneously disclosed to the public. The Commission reviews and accepts codes of conduct and market-based rate tariffs as part of the power marketer's application for market-based rate authority.

7. Standards of conduct are contained in the Commission's regulations[4] and generally require that the employees of a transmission provider engaged in transmission system operations function independently of those employees engaged in the wholesale

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[2]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, 99 FERC ¶ 61,272 (2002) (Show Cause Order).

[3]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies, Docket No. PA02-2-000, August , 2002. This report is available on the Commission's website at: http://www.ferc.gov/electric/bulkpower/pa02-2/pa02-2.htm

[4]18 C.F.R. § 37.4 (2002).

20020813-3045 Received by FERC OSEC 08/13/2002 in Docket#: EL02-114-000

merchant function (and also of employees engaged in the wholesale merchant function of any of the transmission provider's affiliates). For example, the standards of conduct require that employees of Portland's transmission function act independently of employees of Portland's merchant function and of employees of EPMI's merchant function.

8. Preliminary evidence, taken from transcripts of recorded telephone conversations, indicates that Portland and Enron knowingly engaged in transactions that may constitute violations of the standards of conduct and/or the companies' codes of conduct and/or market-based rate tariffs.

9. For example, in the transcripts, an Enron employee explains to a Portland employee that they cannot buy and sell energy directly, but must use a non-affiliated utility as a middle man. There is also evidence that Portland employees believed that the requests they were receiving from their affiliates were improper. For example, when two Portland transmission function employees are discussing an Enron request for such a three-party arrangement, one reports that a third employee thinks the arrangement is not legal. In another instance, a Portland transmission function describes the three-party arrangement as "a scam." In addition, Portland has failed to properly post data related to sales to Enron for a significant amount of transactions.

10. This information supports further investigation. We will accordingly initiate a separate proceeding to investigate possible violations by Portland and Enron (specifically, EPMI) of their codes of conduct or market-based rate tariffs and the Commission's standards of conduct, and the imposition of any appropriate remedies.

11. Staff's initial on-site investigation in Portland, Oregon, identified questionable transactions with affiliates. Subsequently, in April 2002, Portland contacted the Commission's enforcement staff and conducted informal discussions about this matter. Issues concerning these affiliate transactions are included in the proceeding we are now initiating.

12. As noted above, in the Show Cause Order, the Commission found that Portland had failed to cooperate with the investigation initiated in the February 13 Order and ordered Portland to show cause why its market-based rate authority should not be revoked. In response to the Show Cause Order, Portland provided information that was largely limited to the previously identified transactions involving Enron. Accordingly, as part of the hearing ordered herein, we will set for hearing the issue of whether Portland has in fact provided all relevant information in the investigation and what the appropriate

remedies for any failure should be, including whether Portland's market-based rate authority should be revoked.

13. In cases where, as here, the Commission institutes a section 206 investigation on its own motion, section 206(b) requires that the Commission establish a refund effective date that is no earlier than 60 days after publication of notice of the Commission's investigation in the Federal Register, and no later than five months subsequent to expiration of the 60-day period. In order to give maximum protection to consumers, we will establish the refund effective date at the earliest date allowed, [5] 60 days after publication of notice of initiation of the Commission's investigation in Docket No. EL02-114-000 in the Federal Register.

14. Section 206(b) also requires that if no final decision is rendered by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to section 206, whichever is earlier, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such a decision. To implement that requirement, we will direct the presiding judge to provide a report to the Commission 15 days in advance of the refund effective date or the conclusion of the 180-day period, whichever is earlier, in the event the presiding judge has not by the earlier of those two dates certified to the Commission: (1) a settlement which, if accepted, would dispose of the proceeding; or (2) an initial decision. The judge's report, if required, shall advise the Commission of the status of the investigation and provide an estimate of the expected date of certification of a settlement or an initial decision.

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and the Federal Power Act, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held in Docket No. EL02- -000, concerning the matters discussed in the body of this order.

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[5] See, e.g., Canal Electric Company, 46 FERC ¶ 61,153, reh'g denied, 47 FERC ¶ 61,275 (1989).

(B) The Secretary shall promptly publish a notice of the Commission's initiation of the proceeding in Docket No. EL02-114-000 in the Federal Register.

(C) The refund effective date in Docket No. EL02-114-000 will be 60 days following publication in the Federal Register of the notice discussed in Ordering Paragraph (B) above.

(D) A presiding judge to be designated by the Chief Judge shall convene a conference in this proceeding to be held within approximately fifteen (15) days of the date the Chief Judge designates the presiding judge, at a hearing room of the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates and to rule on all motions (except motions to dismiss), as provided in the Commission's Rules of Practice and Procedure.

(E) The presiding judge shall advise the Commission, no later than 15 days prior to the refund effective date, in the event that the presiding judge has not by that date certified to the Commission a settlement which, if accepted, would dispose of the proceeding or issued an initial decision, as to the status of the proceeding and the best estimate of when the proceeding will be disposed of by the presiding judge.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.,
Deputy Secretary.

100 FERC ¶ 61,187

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Avista Corporation
Avista Energy, Inc.
Enron Power Marketing, Inc.
Portland General Electric Corporation

Docket No. EL02-115-000

ORDER INITIATING INVESTIGATION, AND ESTABLISHING HEARING PROCEDURES AND REFUND EFFECTIVE DATE

(Issued August 13, 2002)

1. In this order we are initiating an investigation into instances of possible misconduct by Avista Corporation and Avista Energy, Inc. (collectively, Avista)[1] and two affiliates of Enron Corporation: Enron Power Marketing, Inc.(EPMI), and Portland General Electric Corporation (Portland) (collectively, Enron) to determine whether the misconduct occurred and if so to determine remedies, including possibly refunds and/or revocation of Avista's and/or Enron's market-based rate authority.

2. As discussed below, we will set the possible misconduct for hearing and establish a refund effective date under section 206 of the Federal Power Act (FPA), 16 U.S.C. § 824e (1994), to provide for refunds should the hearing indicate that they are warranted.

Background

3. On February 13, 2002, the Commission directed a Staff fact-finding investigation into whether any entity manipulated short-term prices in electric energy or natural gas

[1]Avista Corporation is a public utility. The utility portion of the company, doing business as Avista Utilities, is an operating division of Avista Corporation. Avista Energy, Inc. is Avista Corporation's marketing affiliate.

markets in the West or otherwise exercised undue influence over wholesale prices in the West for the period January 1, 2000 forward.[2]

4. On May 8, 2002, Commission Staff issued a data request concerning various trading strategies of sellers of wholesale electricity and/or ancillary services in the United States portion of the Western System Coordinating Council during 2000-2001. The specific trading strategies were those identified in three Enron memoranda that were provided by Enron to the Commission in response to a data request.[3] Among the sellers to whom the data request was sent are public utilities who were granted market-based rate authority by this Commission based on a finding that they lacked market power and there was no evidence of affiliate abuse or reciprocal dealing.

5. On June 4, 2002, the Commission issued an order finding that Avista and others had failed to cooperate with the Commission investigation and ordered those companies to show cause why their authority to charge market-based rates should not be revoked as a result of their failure to comply with the Commission-ordered investigation.[4]

Discussion

6. In a Commission Staff initial report, being publicly released concurrently with this order,[5] Commission Staff states that it has obtained preliminary evidence that Avista and Enron may have engaged in some of the trading strategies, identified in the Enron memoranda.

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[2]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, 98 FERC 61,165 (2002) (February 13 Order).

[3]Two of the memoranda were dated December 6, 2000, and December 8, 2000. The third memorandum is undated. The three memoranda and a follow-up data request are posted on the Commission's web page for Docket No. PA02-2-000, which is located at: http://www.ferc.gov/electric/bulkpower/pa02-2/pa02-2.htm

[4]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, 99 FERC ¶ 61,272 (2002) (June 4 Order).

[5]Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies, Docket No. PA02-2-000, August , 2002. This report is available on the Commission's website at: http://www.ferc.gov/electric/bulkpower/pa02-2/pa02-2.htm

7. In its answer to Staff's initial data request of May 8, 2002, concerning various trading strategies, Avista did not admit to involvement in any of the trading strategies. In response to the Show Cause Order, Avista now admits that, in a middleman capacity, it facilitated certain transactions identified by Portland in Portland's response to the May 8, 2002 data request. In fact, Avista states that it routinely acted as a middleman between affiliates such as EPMI and Portland in order to allow transactions to proceed which affiliates would be forbidden to undertake directly. Avista states that it did so as an accommodation to maintain good relations with common trading counterparties. In fact, Avista states that: "the Avista Utilities traders believed that they were performing a common industry function as an intermediary between two parties who are restricted in dealings to facilitate real trades and a robust and liquid market." Avista fully admits now that its own traders "did have questions about the transactions."

8. While admitting that this was part of its standard business practice (that is, to facilitate transactions which were prohibited among affiliates directly), Avista made no attempt to go beyond the discrete transactions previously revealed by Portland. Avista argues that, because its tapes cannot be reviewed by electronic search methods, "there was no way for Avista Utilities to conduct any kind of meaningful review of all, or even a portion, of the telephone conversations in its possession and no way to focus such a review."

9. Avista asserts that the Commission cannot revoke its market-based rates without an investigation under Section 206 of the FPA and that the Commission cannot impose any form of sanction for Avista's failure to respond because the data request violated the Paperwork Reduction Act.

10. Avista claims that it was "used" unwittingly by Enron. However, this is not reconcilable with Avista's acknowledged practice of acting as an affiliate go-between as a routine matter. Nor are we convinced by its claim that, without electronic search methods, it is incapable of coming forth with a thorough analysis of its own activities. This response is in sharp contrast to many other entities that made a considerable effort to provide full and complete responses to the Staff data requests.

11. Accordingly, the Commission will institute a section 206 proceeding to investigate Avista's activities over the 2000-2001 period. This investigation will address the extent to which Avista engaged in or facilitated the trading strategies identified in the Enron

memoranda[6] as well as the circumvention of prohibitions on affiliate sales, and the imposition of any appropriate remedies such as refunds and revocation of market-based rates.

12. As noted above, in the Show Cause Order, the Commission found that Avista had failed to cooperate with the investigation initiated in the February 13 Order and ordered Avista to show cause why its market-based rate authority should not be revoked. In response, Avista provided only information related to the transactions that were previously identified by Portland in response to data requests. Avista further indicated that if additional questionable transactions in which it was identified as a participant were reported by others, it would provide information if requested. Accordingly, we will set for hearing the issue of whether Avista has in fact provided all relevant information in the investigation and what the appropriate remedies for any failure should be, including whether Avista's market-based rate authority should be revoked.

13. In cases where, as here, the Commission institutes a section 206 investigation on its own motion, section 206(b) requires that the Commission establish a refund effective date that is no earlier than 60 days after publication of notice of the Commission's investigation in the Federal Register, and no later than five months subsequent to expiration of the 60-day period. In order to give maximum protection to consumers, we will establish the refund effective date at the earliest date allowed,[7] 60 days after publication of notice of initiation of the Commission's investigation in Docket No. EL02-115-000 in the Federal Register.

14. Section 206(b) also requires that if no final decision is rendered by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to section 206, whichever is earlier, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such a decision. To implement that requirement, we will direct the presiding judge to provide a report to the Commission 15 days in advance of the refund effective date or the conclusion of the 180-day period, whichever is earlier, in the event the presiding judge has not by the earlier of those two dates certified to the Commission: (1) a settlement which, if accepted, would dispose of the proceeding; or (2) an initial decision. The judge's report, if required, shall advise the Commission of the status of the

[6]See supra note 3.

[7]See, e.g., Canal Electric Company, 46 FERC ¶ 61,153, reh'g denied, 47 FERC ¶ 61,275 (1989).

investigation and provide an estimate of the expected date of certification of a settlement or an initial decision.

The Commission orders:

(A) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and the Federal Power Act, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R., Chapter I), a public hearing shall be held in Docket No. EL02-115-000, concerning the matters discussed in the body of this order.

(B) The Secretary shall promptly publish a notice of the Commission's initiation of the proceeding in Docket No. EL02-115-000 in the Federal Register.

(C) The refund effective date in Docket No. EL02-115-000 will be 60 days following publication in the Federal Register of the notice discussed in Ordering Paragraph (B) above.

(D) A presiding judge to be designated by the Chief Judge shall convene a conference in this proceeding to be held within approximately fifteen (15) days of the date the Chief Judge designates the presiding judge, at a hearing room of the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates and to rule on all motions (except motions to dismiss), as provided in the Commission's Rules of Practice and Procedure.

(E) The presiding judge shall advise the Commission, no later than 15 days prior to the refund effective date, in the event that the presiding judge has not by that date certified to the Commission a settlement which, if accepted, would dispose of the proceeding or issued an initial decision, as to the status of the proceeding and the best estimate of when the proceeding will be disposed of by the presiding judge.

By the Commission.

(S E A L)

Linwood A. Watson, Jr.
Deputy Secretary.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

In Reply Refer To:
OED-DRA
Docket No. FA00-29-000

OCT 1 1 2000

Transwestern Pipeline Company
Attention: Mr. Robert Chandler
Director, Accounting and Reporting
1400 Smith Street
Houston, TX 77002

The Office of the Executive Director (OED), formerly the Office of Finance, Accounting and Operations, has completed the audit of annual charges at Transwestern Pipeline Company (Transwestern). The scope of the audit was limited to examining the books and records of Transwestern relating to annual charges for the period January 1, 1997, through December 31, 1998.

The overall audit objective was to determine Transwestern's compliance with Commission accounting requirements and regulations as related to the calculation and assessment of annual charges under 18 CFR Part 382. Specifically, the audit verified the accuracy of the data reported in the Form 2. The audit validated the accuracy of the data through selective testing of invoices supporting the individual account balances of Gas Operating Revenues. In addition, we performed trend analyses of dekatherms reported, reviewed company internal controls, and examined procedures related to the preparation of Form 2. We conducted the audit in accordance with generally accepted government auditing standards as implemented by the Chief Accountant.

The audit did not identify any instances of non-compliance requiring Transwestern to take corrective actions.

The Commission delegated the authority to act in this matter to the Office of the Executive Director under 18 CFR § 375.312. This letter order constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 CFR § 385.713.

001013.0091.2

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OCT 1 1 2000

This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention.

I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Timothy Smith, Project Manager, at 202-208-0918.

Sincerely,

John Delaware

John M. Delaware
Deputy Executive Director
and Chief Accountant
Office of the Executive Director

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

In Reply Refer To:
OED-DRA
Docket No. FA00-26-000

OCT 11 2000

Northern Natural Gas Company
Attention: Mr. Robert Chandler
Director, Accounting and Reporting
1400 Smith Street
Houston, TX 77002

The Office of the Executive Director (OED), formerly the Office of Finance, Accounting and Operations, has completed the audit of annual charges at Northern Natural Gas Company (Northern Natural). The scope of the audit was limited to examining the books and records of Northern Natural relating to annual charges for the period January 1, 1997, through December 31, 1998.

The overall audit objective was to determine Northern Natural's compliance with Commission accounting requirements and regulations as related to the calculation and assessment of annual charges under 18 CFR Part 382. Specifically, the audit verified the accuracy of the data reported in the Form 2. The audit validated the accuracy of the data through selective testing of invoices supporting the individual account balances of Gas Operating Revenues. In addition, we performed trend analyses of dekatherms reported, reviewed company internal controls, and examined procedures related to the preparation of Form 2. We conducted the audit in accordance with generally accepted government auditing standards as implemented by the Chief Accountant.

The audit did not identify any instances of non-compliance requiring Northern Natural to take corrective actions.

The Commission delegated the authority to act in this matter to the Office of the Executive Director under 18 CFR § 375.312. This letter order constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 CFR § 385.713.

001013.0094.2

This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention.

I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Timothy Smith, Project Manager, at 202-208-0918.

Sincerely,

John Delaware

John M. Delaware
Deputy Executive Director
and Chief Accountant
Office of the Executive Director

Jurisdictional companies are required to maintain their books and records in accordance with the Commission's Uniform System of Accounts (USofA). The USofA provides basic account descriptions and accounting definitions that are useful in understanding the information reported in the Form Nos. 1, 1-F, 2, 2A, and 6.

In order to make the accounting regulations more accessible, the Commission's accounting requirements were extracted and reproduced here from the Code of Federal Regulations available on the U.S. Government Printing Office's GPO Access Web Site. The page numbers that appear in these files refer to the page numbers contained in the Code of Federal Regulations. The GPO updates these files annually.

An official paper copy of the USofA can be obtained from the U. S. Government Printing Office, Superintendent of Documents, Mail Stop: SSOP, Washington, DC 20402-9328; or call (202) 512-1800. Ask for the Code of Federal Regulations, Title 18, Parts 1-399. The accounting requirements for jurisdictional electric companies, natural gas companies, and oil pipeline companies are found at Parts 101, 201, and 352, respectively.

Company	Docket No.	Audit Period (Date Audit Started - Date Report Issued)	Comments	Contact	Audit Manager
Florida Gas Transmission Financial Audit	FA91-23-000	1/1/91 - 7/14/92	Audit report issued 7/14/92	Assistant Controller, John P. Trevelise	Kenneth Anderson - FERC
Florida Gas Transmission Financial Audit	FA94-15-000	Audit ended 11/12/96	Contested audit issues settled 11/12/96	Director of Financial Accounting, James M. Saunders	Joseph Frangipane, Director Division of Audits - FERC
Northern Border Pipeline Co. Financial Audit	FA93-45-000	4/19/93 - 5/17/96	Audit report issued 5/17/96	Controller, Patricia M. Wiederholt	John Okrak - FERC
Northern Border Pipeline Co. Construction Audit	FA98-007-000	4/12/99 - 10/12/99	Audit report issued 10/12/99	Controller, Patricia M. Wiederholt	Dwight Siddell - FERC
Northern Natural Gas Company Financial Audit	FA93-48-000	6/1/93 - 8/28/95	Audit report issued 8/28/95	Director, Accounting and Reporting, Robert Chandler	Joseph Frangipane, Director Division of Audits - FERC
Northern Natural Gas Company Abandonment Audit	FA98-003-000	4/09/98 - 9/12/00	Audit report issued 9/12/00	Director, Accounting and Reporting, Robert Chandler	Dwight Siddell, - FERC
Northern Natural Gas Company Annual Charges Audit	FA00-026-000	4/25/00 - 10/11/00	Audit report issued 10/11/00	Director, Accounting and Reporting, Robert Chandler	Timothy Smith - FERC
Northern Natural Gas Company Construction Audit	FA00-038-000	7/28/00 - 12/7/01	Audit report issued 12/7/01	Director, Accounting and Reporting, Robert Chandler	Dwight Siddell - FERC
Transwestern Pipeline Company Financial Audit	FA94-16-000	1/3/94 - 4/11/96	Audit report issued 4/11/96	Vice President and Controller, Mr. E.G. Parks	Kenneth Anderson - FERC
Transwestern Pipeline Company Annual Charges Audit	FA00-029-000	4/25/00 - 10/11/00	Audit report issued 10/11/00	Director, Accounting and Reporting, Robert Chandler	Timothy Smith - FERC
Midwestern Gas Transmission Co. Financial Audit	FA91-72-000	9/16/91 - 4/09/92	Audit report issued 4/09/92	Controller, Bill J. Walls	Kenneth Anderson - FERC
Midwestern Gas Transmission Co. Financial Audit	FA94-9-000	11/15/93 - 10/20/94	Audit report issued 10/20/94	Assistant Controller, Mr. Gregory G. Gruber	Kenneth Anderson - FERC
Portland General Electric Co. Annual Charges Audit	FA00-2-000	11/23/99 - 5/25/00	Audit Report issued 05/25/00	Vice President of Finance, Mrs. Mary K. Turina	Timothy Smith - FERC
Portland General Electric Co. Generation Cost Audit	FA01-10-000	5/1/01 - Present	In-Progress	Controller & Assistant Treasurer, Mr. Kirk M. Stevens	Thomas McLaughlin - FERC
Transwestern Pipeline Co. Financial Audit	FA94-16-000	12/7/93 - 4/11/96	Audit Report issued 04/11/96	Vice President & Controller, Mr. E. G. Parks	Bryan Craig - FERC
Transwestern Pipeline Co. Annual Charges Audit	FA00-29-000	5/11/00 - 10/11/00	Audit Report issued 10/11/00	Director, Accounting & Reporting, Mr. Robert Chandler	Timothy Smith - FERC

RIMS Doc ID 1877630

To: Doug, Robin
From: Lee
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SWIDLER BERLIN SHEREFF FRIEDMAN, LLP

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FEDERAL ENERGY
REGULATORY COMMISSION

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August 19, 1998

Committee on Governmental Affairs
EXHIBIT #A-51

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **AES Redondo Beach, LLC, Docket No. ER98-2843-000; AES Huntington Beach, LLC, Docket No. ER98-2844-000; AES Alamitos, LLC, Docket No. ER98-2883-000; Long Beach Generation, LLC, Docket No. ER98-2972-000; El Segundo Power, LLC, Docket No. ER98-2971-000; Ocean Vista Power Generation, LLC, Mountain Vista Power Generation, LLC; Alta Power Generation, LLC; Oeste Power Generation, LLC; Ormond Beach Power Generation, LLC, Docket No. ER98-2977-000**

Dear Secretary Boergers:

Enclosed please find an original and fourteen copies of the "Preliminary Report on ISO's Ancillary Services Market" of the California ISO Market Surveillance Committee prepared in compliance with the Commission's July 17, 1998, Order in the above-identified proceedings.

Also enclosed is a form of notice, in hard-copy and electronic form, and an additional copy of the letter. I would appreciate your having the additional copy stamped with the date and returning it to the messenger.

Yours truly,

Michael E. Ward
Counsel for the California ISO

(Enclosures)

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AUG 19 1998

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Market Surveillance Committee
California Independent System Operator

Frank A. Wolak, Chairman
Robert Nordhaus, Member
Carl Shapiro, Member

Memorandum

To: Governing Board of California Independent System Operator

From: Market Surveillance Committee

Re: Preliminary Report on ISO's Ancillary Services Market

Date: August 19, 1998

Attached is the California Independent System Operator (ISO) Market Surveillance Committee's preliminary report to the ISO's Governing Board on the operation of the ISO's ancillary services markets.

This report is a preliminary one which the Committee may wish to supplement after review of public comments or on the basis of subsequently acquired data.

The Committee requests that the Board make this report available to the public and to interested Federal and State Agencies.

ORIGINAL

Preliminary Report On the Operation of the Ancillary Services Markets of the California Independent System Operator (ISO)

Prepared by the Market Surveillance Committee of the California ISO[*]

Frank Wolak, Chairman
Robert Nordhaus, Member
Carl Shapiro, Member

August 19, 1998

[*]We wish to acknowledge the invaluable insights of James Bushnell of the University of California Energy Institute about the operation of these markets. The Market Surveillance Unit of the Independent System Operator responded to our numerous data requests and provided other very useful assistance. Lastly, we wish to thank Gary Ackerman, Severin Borenstein, Fred Mobasheri, Robert Wilson, representatives of Duke Energy, Dynergy, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, the Management and Governing Board of the ISO and participants at the Aug. 12th open meeting of the Market Surveillance Committee.

Summary of Findings and Recommendations

The Market Surveillance Committee of the California Independent System Operator has conducted a preliminary review of the performance of the ISO's ancillary services markets, and offers here recommendations for improving that performance. Further and more definitive recommendations must await additional market experience and further data analysis, as these markets remain in a state of flux.

The Committee finds that the ISO's ancillary services markets do not yet operate in a manner consistent with workable competition. Compared to the Power Exchange (PX) and supplemental energy markets, prices in the ancillary services markets do not fluctuate in a manner that reflects changes in the underlying marginal costs of supplying these products. Ancillary services markets have exhibited extreme price volatility, even during periods when demand was unchanged for long periods of time. The conditions are not yet in place to rely on these markets to set efficient, cost-reflective prices. Prices for lower quality services such as replacement reserve routinely exceed the prices for higher quality services such as regulation. Often ancillary services capacity prices exceed both the power exchange and real-time energy price for the same hour. Until workable competition has been established, the Committee recommends that the ISO continue to utilize a price cap for ancillary services.

We have identified nine underlying factors contributing to the inefficient operation of the ISO's ancillary services markets: (1) some firms are subject to cost-based price caps while others are allowed to earn market-base rates; (2) the demand for ancillary services has been higher than anticipated; (3) the amount of each ancillary service demanded by the ISO does not depend on market prices and these demands are not procured in a rational manner; (4) perverse incentives for generator bidding behavior have been created by reliability must-run contracts; (5) the ISO has often purchased ancillary services seperately from small geographic areas, increasing the potential for the exercise of market power; (6) the ISO's dispatch practices have not been transparent to market participants; (7) the allocation of ancillary services costs to scheduling coordinators has been flawed; (8) suppliers of ancillary services from outside of the ISO control area have been excluded; and (9) the ISO's computer systems are still facing various software difficulties that are not yet fixed.

While we have not been able to precisely measure the relative significance of each of these problems, preliminary analyses do provide some insights. The quantities of ancillary service purchased have far exceeded the levels at which they have historically been acquired. High demand is not a direct cause of the market irregularities, but the substantial quantities acquired appears to have increased the impact of the other factors. Prices for 'inferior' ancillary services have routinely exceeded those for 'superior' services. The lack of substitution in the consumption of these services therefore appears to have significantly impacted the cost of acquiring them. Lastly, it appears that RMR copntracts are not doing much to reduce market power problems, and are most likely contributing to them. Our preliminary results indicate that RMRs provide an incentive to

EC 001207805

withhold generation capacity from these markets.

The Committee recommends to the ISO the following specific remedies to enable the ISO's ancillary services markets to become workably competitive: (1) adopt rational and transparent purchasing practices for ancillary services, seeking additional regulatory flexibility as needed; (2) revise and supplement the reliability must-run contracts; (3) support the move towards market-based rates for all market participants, using the requirement that owners of significant amounts of generation capacity sign financial contracts for differences to mitigate their incentives to exercise market power in these markets; (4) retain the authority to impose a "damage control" price cap and exercise that authority until these markets are demonstrably competitive; (5) purchase ancillary services using a state-wide auction, using reliability must run constracts to supplement zonal shortfalls in capacity from this market-clearing mechanism and (6) revise purchasing protocols to help reduce the need for regulation services.

EC 001207806

Table of Contents

EC 001207807

1. Introduction

This report summarizes the observations and recommendations of the market surveillance committee (MSC) of the California Independent System Operator (ISO) concerning the current design and operation of the ISO's ancillary services markets. On June 30, the Federal Energy Regulatory Commission (FERC) granted permission for three generation units owned by AES Corporation to earn market-based rates for the sale of ancillary services in California. Similar permission was subsequently granted to other generation units recently divested from the incumbent investor-owned utilities. Over the following weeks, these markets experienced enormous price swings within and across days. On July 17, FERC rejected the request of the ISO and other market participants to stay FERC's decision granting these firms market-based rates, but upheld the ISO's authority to set a maximum price at which it will purchase ancillary services (the "price cap"). The July 17 order also requested that the market surveillance committees of both the ISO and the California Power Exchange conduct an independent review of these markets.

This document provides a qualitative description and analysis of the ancillary services markets. The short deadline for preparing the report and initial software problems associated with extracting the large amounts of necessary data from the ISO's internal databases prevented the MSC from undertaking a comprehensive quantitative analysis of the performance of these markets over the months of June and July. To supplement its data analysis, the MSC and the ISO's market surveillance unit conducted joint telephone interviews with representatives from the majority of the large market participants to understand their perspective on the shortcomings of the current design and operation of the ISO's ancillary services markets. In addition, an open meeting of the MSC was held on August 12th to solicit further input from market participants and other interested parties. We are grateful to these individuals and organizations for their valuable input. Our report is based on the empirical analysis of market data we have been able to able to perform up to the present time, input from market participants, and our discussions with the staff and consultants to the market surveillance unit of the ISO.

This report identifies several factors that we believe have created problems with these markets that have been much more severe than those experienced in the energy markets of both the ISO and the PX. It is important to note that significant changes have taken place in these markets during the last month, and these markets remain in flux. Thus, any analysis of ancillary-services markets in California at this time must be viewed as preliminary. Both the market surveillance committee and the market surveillance unit of the ISO are continuing to perform further quantitative studies. The MSC is currently undertaking more detailed analyses of the vast amounts of data now available from the ISO's Market Surveillance Unit. We are hopeful that these ongoing studies will shed further light on the performance of these markets, the relative significance of the various factors identified below, and on the potential benefits of the proposals discussed in this report. We understand that an opportunity will be provided for public comment on this report. The Committee intends to review those comments and to revise or supplement this report as appropriate.

It is not our intention in this report to attribute "blame" for the recent market disruptions to any firm or set of firms. Such an assessment would, among other things, entail a detailed examination of bidding behavior that we have not had the time, resources, or, until very recently, the necessary data to perform. Additionally, because the market is continuing through a transition period, it would be premature to state that any firm has achieved "sustainable" market power. We also do not claim to provide an exhaustive list of the individual problems that plague these markets. There are many implementation difficulties, notably technical and software problems, that we do not feel qualified to comment on at length. We are instead trying to assess the overall functioning of the market. This report therefore focuses on what we feel to be the major problems relating to the design, implementation, and regulation of these markets.

The committee wishes to reaffirm its confidence that *properly functioning* market processes can effectively set prices in the electricity industry. At the same time, we also recognize that in the process of assembling a complex set of interactive market protocols under short time deadlines, serious flaws are almost inevitable. Some of these flaws can result in market disturbances that, at times, make necessary some form of intervention into the market. The hope of this committee, and most all market participants, is that the most serious flaws can be corrected as quickly as possible, thereby greatly reducing the need for intervention. The Committee would like to emphasize, however, that the a true market system in electricity, as in telecommunications and other industries undergoing the transition from regulation to competition, cannot be achieved overnight; during the transition period, dangers arise if some participants are afforded the flexibility we associate with the market system while others remain subject to restrictive rules.

In Section 2, we provide an overview of the ISO ancillary services market design as it was originally conceived. We also point out that the implementation of the ISO's markets has differed from the intended design in several significant ways. In Section 3, we give an overview of the ancillary services market performance over the period of its operation, breaking out three distinct time periods for our analysis. Section 4 analyzes the structural problems that have plagued these markets and contributed to the difficulties experienced in these markets to date. In Section 5, we present several proposals for revising the design and implementation of these markets. Section 6 offers conclusions.

2. Design Philosophy of the ISO's Electricity Product Markets

In this section we describe the ancillary services product markets that are operated by the ISO. We focus here on the *intended* operation of these markets, i.e., the way these markets are described in the ISO tariff and protocols. In fact the operation of these markets currently differs from the intended design in several important ways. The impact of these differences will be the focus of later sections.

The California ISO has responsibility for implementing and monitoring markets for several products. Electrical energy is not, technically, one of those products. In theory, the ISO's role is one of "gatekeeper" to the underlying central market for electrical energy. As the gatekeeper, the ISO is responsible for assuring that all qualifying traders have access to whatever suppliers and customers of electricity that they wish to transact with. In the process of providing such access, the ISO is responsible for acquiring a variety of reserve, or "ancillary services," monitoring and billing traders that consume these services, and operating a *de facto* market for transmission congestion management. In this report we concentrate on the ISO's responsibilities for acquiring, dispatching, and charging for ancillary services.

The focal point of the ISO operations is in many ways the market for energy "imbalances." The term imbalance refers to a discrepancy between the amount of energy a trader, or scheduling coordinator (SC), has told the ISO in advance it will provide or consume, and the amount that it actually supplies or consumes in real-time. That is to say, any power that was supposed to be provided by an SC, but was instead procured by the ISO, is billed to that SC at the going rate for imbalances. In this sense, the imbalance market can be viewed as the true spot market for power, since it represents the instantaneous cost of procuring the commodity electrical energy.

2.1. Ancillary Service Markets

The ISO is responsible for acquiring or monitoring the acquisition of 6 ancillary service products. These products and the corresponding service requirements are listed in Table 1.

EC 001207810

Product	Performance Requirement	Proposed Quantity Supplied
Regulation Reserve	Instantaneous: automatically controlled by the ISO	Operator's discretion Historically about 3% of load
Spinning Reserve	On-line, produce within 10 min	Sum of both spin sources equals approximately 6.7% of load
Non-spinning Reserve	Off-line, produce within 10 min	
Replacement Reserve	1 hour	Difference between scheduled and ISO forecast demand[1]
Voltage Support/Reactive Supply	As needed	As needed
Black Start	WSCC standards	WSCC standards

Table 1: Ancillary Service Products

Of these six ancillary services, the last two, voltage support and black start, are not acquired through a day-ahead hourly market-clearing process. These are instead procured through a longer term contracting process. This could be an option for some of the other services, as we discuss later. In this report, we will focus on the other four services. On the day before these services are required, the ISO holds auctions for each service, determining a market-clearing capacity ($/MW) price for each. Thus, in theory, successful bidders into these markets will be rewarded for making capacity available to the ISO to provide power under certain conditions and requirements. Successful bidders into each of these markets may or may not in fact be called upon to provide energy. As we will discuss later, the conditions under which units bidding into the spin and non-spin markets may be called to supply imbalance energy are currently somewhat ambiguous. If these units are called upon to provide real-time energy, suppliers to the spin, non-spin, and replacement reserve markets are paid the imbalance energy price for any energy that they provide. This payment is *in addition* to the capacity payment they receive for making their capacity available to the ISO. Due to metering and software limitations, suppliers of energy into the regulation market cannot set or earn the imbalance energy price for any energy that they provide.[2] Suppliers of regulation energy instead earn the Regulation Energy Payment Adjustment (REPA), a dollar per MW of regulation capacity bid payment that is set according to an *estimate* of the energy provided by each supplier.[3]

[1] Until recently, the ISO capped its replacement reserve purchases at 1000 MW.

[2] This is a departure from the original design of the regulation market.

[3] Proposed Amendment 8 to ISO Tariff filed May 19, 1998, conditionally accepted June 24, 1998 in Order

Suppliers bidding to provide any of these four ancillary services must satisfy various technical operating characteristics for each of these markets. Bidding in each market consists of a capacity price ($/MW) and a schedule of energy price ($/MWh) and quantity (MWh) bids. In selecting the "winners" of each market auction, the ISO selects suppliers in increasing order of their *capacity* prices ignoring, their energy price bids.[4] The market clearing ancillary service price paid to all winning bidders not subject to cost-based price caps is set at the capacity price bid of the last bidder whose capacity is accepted. Those winning bidders subject to cost-based price caps are currently paid their bid price for the quantity of each ancillary service that they supply to the market. An important feature of the operation of these markets is that although firms submit their bids to all of these ancillary services markets simultaneously, the markets clear sequentially, with regulation first, followed by spin, non-spin, and finally, replacement. All four markets are cleared and bidders are told the market clearing prices and how much of their capacity was accepted for each market. In this sequential market-clearing process, capacity that is won in a previous auction is subtracted out from the capacity that is bid into the subsequent markets. For example, if a participant bids 100 MW of a generating unit into regulation and 200 MW into spin and wins 50 MW in regulation at the regulation bid price, then 200 MW – 50 MW = 150 MW is actually bid into the spin market at the spin bid price. If 80 MW is won in the regulation market, then only 120 MW is actually bid into the spin market at the spin price. If 100 MW is bid into regulation and 50 MW is bid into spin, even if *none* of the 100 MW of bid into regulation is taken in the regulation market, only 50 MW is bid into the spin market. The impact of this feature of the current market-clearing protocol on the efficiency of the ancillary services market will be discussed later in this report.

A final important feature of the ancillary services markets that affects the incentives of bidders in these markets is the mechanism used to pay for ancillary services. Currently, the ISO charges SCs for their share of the total costs of the four ancillary services procured from these four markets based on each SC's share of total scheduled energy. However, the cost ancillary services provided under an RMR contract is charged to the transmission company local to that facility. This difference in the payment mechanism for ancillary services based on whether or not they are purchased through the market or under an RMR contract should affect the incentive of generating companies differentially depending on the amount of transmission facilities they owns and whether they are a net demander or supplier of electricity.

Accepting Proposed Tariff Amendment for Filing, Providing Clarification and Guidance, 83 FERC 61 309.

[4] When there is a capacity price tie for the right to provide ancillary service capacity, instead of choosing the producer with the lowest energy price, the capacity award is allocated equally among all producers involved in the tie.

2.2. Imbalance Energy Market

Operation of the imbalance energy market, while not technically an ancillary service market, nevertheless constitutes an important commercial function of the ISO. The imbalance energy price is, in practice though not in name, a spot price for energy in the ISO system. The imbalance price, which is calculated at 10-minute intervals, is the only *energy* price set through ISO market processes. This price is used to settle deviations from scheduled supply and demand: those providing extra supply[5] (or reduced demand) will earn this price and those providing extra demand (or under supply) will pay it.[6]

The ISO acquires energy from any one of five sources: from the four hourly ancillary services markets, and from suppliers who bid to provide "supplements" to their day-ahead energy schedules. As described earlier, suppliers who have committed capacity to one of the ancillary service markets, excepting regulation, and who also produce energy, receive the imbalance energy price in addition to their respective ancillary service capacity payment. Suppliers who provide energy through supplemental energy bids receive the imbalance energy payment only.

Each ancillary services provider will have submitted bids to supply energy from its ancillary service capacity. Other generators may submit energy bids for the imbalance market through supplemental energy bids. The ISO combines these energy bids into a system-wide bid-curve for incremental energy.[7] If additional energy is needed in real time, the ISO will dispatch, subject to technical operating constraints on the units, the unit with lowest energy bid that is currently available, thereby moving "up" the bid stack. Generation and demand that has already been scheduled can also submit "decremental" adjustment bids to be used in the event that supply exceeds demand in real time. A decremental bid represents a price that a generator or load source would pay to the ISO in exchange for the right to either reduce supply or increase demand. When supply exceeds demand, the ISO calls on the highest priced decremental bid to restore balance. The 10-minute imbalance price is set at the price of the last, or marginal, unit of supply or demand that was called on to adjust its schedule. In the case of undersupply this would be the highest incremental bid taken. In the case of oversupply this would be the lowest decremental bid. All instructed deviations from a generator's schedule, those ordered by the ISO in real-time as it moves up or down the supplementary energy bid

[5] The difference between scheduled and actual supply will also reflect an updated scaling factor to account for transmission losses. Supply adjustments for transmission losses are discussed in more detail below.

[6] Although the imbalance price is updated every 10 minutes, the system is initially capable only of tracking imbalance *quantities* once an hour. The settlement charges currently are thus based upon the average of the six imbalance prices from each hour.

[7] We assume, for simplicity, there is no congestion. If there is congestion in the real-time market, then prices are set on a zonal basis.

stack, are settled at the 10-minute price in force when the instruction was given to the generator. All generators supplying electricity during a given hour can also make uninstructed deviations from their schedules in real-time for economic or unit reliability reasons. However, the ISO is only able to measure deviations from hourly generation schedules. Currently, these hourly uninstructed deviations up or down relative to a generator's hourly schedule are settled at the average of the six 10-minute prices relevant for that hour. This price is referred to as the hourly real-time energy price.

2.3. Ancillary Services Market Prices Under Ideal Conditions

Before describing the market outcomes experienced to date in the ISO's ancillary services markets, it is useful to consider what we would expect the relationship between the prices in these various markets to be under ideal circumstances. By "ideal circumstances," we mean at least five specific conditions hold: (1) no market participant has market power; (2) transactions costs are minimal; (3) suppliers and consumers are risk neutral; (4) there are no physical, regulatory, or software-based entry barriers that restrict the pool of potential suppliers in any of these individual markets; and (5) the ISO has the flexibility to act as a rational buyer, including the authority to enter into contracts with suppliers to serve its anticipated needs for ancillary services. We stress that these conditions represent *ideal* circumstances, and are unlikely to be fully met in practice; however, we are confident that the closer actual conditions in the ISO's ancillary services markets come to these ideal conditions, the greater is the likelihood that these markets will bring the full benefits of competition to California electricity consumers.

Under these ideal conditions, we would expect prices in each of the ISO's markets (as well as the PX) to equilibrate so that suppliers to any of one these markets would expect to earn roughly the same amount of variable profit (total revenue less total variable costs) regardless which market they choose to bid their generating capacity into. Thus, under ideal circumstances we would not expect any significant arbitrage opportunities between these markets from shifting generating capacity across these markets within the day and across days.

Under these conditions, the equilibrium capacity price for supplying non-spinning reserve and replacement reserve should be very close to zero if two additional conditions are met. These are: (1) the facilities supplying capacity in these two reserve markets and generators bidding into the supplemental energy market are both dispatched in the real-time energy market according to their energy price bids only[8] and (2) there are bids made into the supplemental energy market.[9] If one of these ancillary service prices w

[8] There may be some additional cost to selling real-time energy by first supplying capacity to the ancillary services market as opposed to simply bidding into the supplemental energy market. These costs would be reflected in the reserve capacity prices, but do not appear to be significant.

[9] Unlike the five conditions listed above, these conditions are often met under current market operations.

substantially greater than zero, we would expect generators bidding into the supplemental energy market to instead bid into the high-priced reserve market. This is because generators can sell imbalance energy through both the reserve markets and supplemental energy bids on a roughly equal footing. A generator could therefore earn a significant capacity price *in addition to* the same expected imbalance energy sales by moving its capacity from the supplemental energy market to the replacement reserve market. This process would continue until there were either no more generating units willing to bid into the supplemental energy market, or the market-clearing capacity price in both of these markets is close to zero. In fact, under these conditions, only a shortage of capacity or the exercise of market power could keep the price of these reserves substantially above zero on a regular basis.

If these ideal circumstances did hold, and there were no market power detected in some of the markets, then the potential for any firm to exercise market power would be minimal in *all* of these markets. In other words, if there were little or no market power detected in the PX or imbalance energy market, there should little or no market power in the ancillary services markets. However, over the last month or so, just the opposite has been the case. While it is too early to make a final determination about the competitiveness of the energy markets,[10] it is clear that prices in the energy markets have not risen as far, or as consistently, above estimates of marginal costs as they have in the ancillary service markets.

Specifically, prices in the ancillary services markets routinely far exceed the prices in day-ahead energy market operated by the Power Exchange and the real-time energy market operated by the ISO. This occurs despite the fact that the cost of providing ancillary services capacity from a generating unit is presumably less than the cost of providing energy from that same unit. Recall that the ancillary services capacity payment requires a unit to stand ready to produce electricity with some time lag, whereas selling into both the PX and the real-time energy market requires the plant owner to actually produce electricity. In providing some reserves, particularly regulation, units can suffer considerably more wear and tear than they would providing energy at a constant level. The provision of regulation and spinning reserves also entails operating a unit at a level below it most efficient output point. We therefore cannot predict *exactly* what the relationship between ancillary services prices and energy prices should be, even under ideal conditions. It is reasonable to assume, however, that the price of regulation and spin should be somewhat related to the real-time price of energy. The price of non-spin and replacement reserve, which do not require the generating unit to be running during the hour its capacity is made available, should be lower than the price of regulation and spin and often approach zero.

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[10] In many electricity markets around the world, severe market power problems are only experienced during times of high demand. The California market has only recently entered its highest demand period, and energy prices have risen rather quickly. Therefore a full assessment of any market power problems will require observing the behavior of the market throughout this period of high demand.

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Therefore, one indication that the ancillary services markets may not be functioning as well as they could be would be very high prices for non-spin and replacement reserve. Furthermore, we would expect the prices of the ancillary services to reflect the relative costs of providing those services. As we discuss below, it is reasonable to assume that the costs of providing ancillary services is declining with the 'stand-by' requirements imposed by providing those services. Providing regulation should therefore cost more than providing spinning reserve, providing spin should cost more than providing non-spin, and providing non-spin should cost more than providing replacement. In a properly functioning market, prices for these services should follow the same pattern.

3. Performance of Ancillary Services Markets

Price movements in these markets have fallen into at least three distinct periods. The first period, March 30 to June 30, was dominated by regulatory effects. The second period, roughly June 30 to July 13, was characterized by severe price volatility and confusion while prices during the last period, from July 14 to the current date were clearly influenced by ISO imposed bid caps. We will discuss each period more detail below.

Date	Event
March 30	Market opens.
May 20	Regulation Energy Payment Adjustment (REPA) is implemented for regulation energy.
June 10	Order issued for new cost-based rates for some divested units.
June 30	AES granted market-based rates, all firms made eligible for market-based rates on replacement reserve.
July 10	Dynergy and Houston Industries granted market-based rates.
July 14	$500 price cap imposed by ISO on all ancillary services.
July 24	ISO price cap revised to $250.
August 6	ISO begins accepting bids for spin, non-spin and replacement for units out of the ISO control area.

Table 2: Important Dates in the Ancillary Services Markets

Because the ancillary services markets from March 30 to June 30 were dominated by the widespread imposition of cost-based caps on the prices received by firms bidding into these markets, there is very little difference in the performance of these markets across months during this time period. Consequently, we reduced the length of our pre-market-based rates control period to June 1 to June 30. All figures presented in the remainder of this report are for the following three time periods: (1) June 1 to June 30: prior to the granting of market-based rates; (2) July 1 to July 13: market-based rates granted for some participants; and (3) July 14 to July 31: imposition by the ISO of a price cap on ancillary services.

Ancillary services are often procured on a zonal basis because of anticipated congestion between North and South of Path 15 (NP15 and SP15). This process often results in different prices for each service for the two geographic zones. We therefore present separate plots for the prices of the four services North and South of Path 15. All of plots discussed in this section have the same scale on the vertical axis for each of there time periods in order to make it more straightforward to assess whether there are changes in hour-to-hour or day-to-day volatility of a given magnitude across the three time periods.

3.1. Basic Data on Market Performance

Figures 1 and 2 present plots of the hourly *prices* North and South of Path 15 (NP15 and SP15), respectively, in the four ancillary services markets broken down by our three time periods. We truncated the scale of these plots at $250/MW in order to better reveal the movements in prices over time in the $0 to $50 range. Values in excess of $250 are simply plotted as $250. Thus, the Figures do not show the sequence of prices from Hours 14 to 18 in the Replacement Reserve Market on July 9 of $2,500, $5,000, $5,000, $5,000, $750. They also do not show the price sequence in this same market for Hours 14 to 18 on July 13 of $9,999, $9,999, $9,999, and $9,999.[11] Across the top of each graph we plot an indicator variable, CONGESTION. The hours that this variable appears at the top of each plot as a "+" denotes those hours when ancillary services were procured on a zonal basis.

Figures 3 and 4 present plots of the hourly *quantities* purchased of the four ancillary services for the three time periods for North and South of Path 15, respectively. Once again, the indicator variable, CONGESTION, shows those hours when ancillary services were procured on a zonal basis.[12]

Figures 5 and 6 present hourly bid sufficiencies for our three time periods for North and South of Path 15. We define "bid sufficiency" as the total capacity submitted in a given hour divided by the ISO's total needs during that hour, measured in percentage terms. A bid sufficiency value of 100% indicates that *just* enough capacity was bid to serve the ISO's needs. A bid sufficiency value of less than 100% indicates that the ISO was unable to cover its demand for that ancillary service from bids submitted to the market. A bid sufficiency value of 1000% indicates that ten times as much capacity was bid into the market as the ISO required. Following our convention for plotting extremely large values of variables, we truncated the vertical axis of our plots at 1000%.[13]

[11] Increasing the scale of the graphs to include these values would completely obscure any movements in prices in the $0-$50 range, which contains the vast majority of the prices.

[12] Data for June 10 for the hourly quantities demanded for all ancillary services were missing from the data set provided to us by the Market Surveillance Unit of the ISO. We chose to plot all of these quantities as zero for all for markets for all hours during that day.

[13] Information is lost by this truncation, since during many hours, enormous bid sufficiency values occurred. These hours appear in the graphs as a value of 1000 in order to better illustrate the variation in

There are several general features of these graphs that are worth noting before we focus on features unique to the three time periods. First, except for the North of Path 15 price graph for the time period July 1 to July 13, there is a tremendous amount of price volatility in these markets. This is true for all of the markets. For example, on Hour 13 of July 9, the hour before the price of replacement reserve hit $2500/MW South of Path 15, the market cleared at a price of $1/MW, despite the fact that the ISO sought 500 MW of replacement reserve for all hours of the day. On July 13, the price of Replacement Reserve in Hour 17, the hour immediately following the string $9999/MW prices, was $0.01/MW.

In order to illustrate the amount of price volatility in these markets, in Figures 7 and 8 we constructed a histogram of prices in each of these markets for each of the three time periods for North and South of Path 15. These histograms give the frequency with which prices in each of the four markets fall into the four ranges: $0 to $50, $50 to $150, $150 to $250 and greater than or equal to $250. The striking feature of these histogram is the almost complete lack of prices in the intermediate, but by no means low-priced, range of $50 to $150. For all markets and time periods except the non-spin market South of Path 15 from July 14 to July 31, this range of prices contains the smallest fraction of the total number of prices for that time period.

The second feature of these plots is the relatively small amount of variation in demand across hours in the day for the spin, non-spin and replacement reserve market. For the replacement reserve market, the quantity purchased both North and South of Path 15 was 500 MW for every hour of every day from June 1 to July 10. From July 15 to July 28, 250 MW was purchased for every hour in each zone. The quantity demanded of both spinning and non-spinning reserve fluctuates very little throughout the day, and the pattern of demand is very similar across days.

A third feature of these graphs, which we discuss in more detail below, is that the demand for regulation reserve is extremely variable across hours in the day and across days. On most days, the hourly demand more than doubles from it lowest value of the day to the highest value of the day in both congestion zones. During some days the peak demand is more than three times the value of the lowest demand for the day. Reasons offered by the ISO operations staff and market participants for this unexpectedly large demand for regulation reserve will be discussed later in this report.

The final feature common to these graphs is the volatility in bid sufficiencies for these markets across hours of the day. Although the average values of bid sufficiencies

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bid sufficiencies around the very important 100% level. Increasing the scale on the vertical axis to capture values of bid sufficiency on the order of 5,000% would make the graph virtually useless for discerning any movements in bid sufficiencies around the 100% value. For the same reason that we had to set the quantities of each ancillary service equal to zero on June 10 in Figures 3 and 4, in these Figures we set the values of bid sufficiency equal to zero for all hours and markets on June 10 because this information was missing from the data provided to us by the Market Surveillance Unit of the ISO.

tend to increase across the three time periods for both North and South of Path 15, this is due primarily to the tremendous increase in the volatility of the bid sufficiencies across the three time periods. For example, in both North and South of Path 15, from June 1 to June 30, the maximum bid sufficiency never exceeded 800%. However, immediately following the extremely high prices in the Replacement Reserve market on July 9, bid sufficiencies far in excess of 1000% began to occur in this market, although periods when there were insufficient bids submitted to this market still occurred during the latter part of July. We now turn to the features of these plots that are unique to each time period.

3.2. June 1 to June 30: Prior to the Granting of Market-Based Rates

From the opening of the markets on March 30 up until the FERC order on June 30, the markets were characterized by chronic shortfalls of capacity offered and extensive dispatch of units under Reliability Must-Run (RMR) contracts. This is shown by the large number of hours that the bid sufficiency numbers were below 100% for this time period both North and South of Path 15. Because all firms bidding into these markets were under costs-based caps during most of this time period, the bid of the highest-priced unit dispatched in each hour was in the range of $5 to $10 per MW. It is important to remember that these are "market prices" in name only, because each firm was eligible to receive, at most, its cost-based bid-cap. For example, if this market price is $10 and the price cap of another unit is $8, then that unit is dispatched and paid its price-cap of $8, despite the fact that some suppliers may be receiving a price of $10 for their capacity. Because of software constraints, the ISO currently pays participants subject to a cost-based price-cap their bid price as opposed the price-cap so long as their bid price is below the market price for that hour.

On June 11, one newly divested unit became eligible (pending review and subject to refund) for a cost-based rate of $244.60/MW for ancillary services. The pattern of prices in Figure 1 reflects this change. Following this date, prices at or slightly below $244.60/MW frequently occurred both North and South of Path 15.

It is important to remember that the prices reported for these services do not accurately reflect the true per-unit average cost to the ISO of procuring its ancillary services needs. This is partly because a firm subject to cost-based rates that is supplying ancillary services receives only its cost-based rate, even if the market price is higher. Furthermore, there was considerable reliance by the ISO on units called under RMR contracts during this period. According to information provided to us by the Market Surveillance Unit of the ISO, some units can earn over $4,000/MW under their RMR contracts for providing these ancillary services, although the vast majority of RMR capacity has reliability payment rates less than $500/MW. Because of these very high reliability payment rates, RMR costs were sometimes considerable. The Market Surveillance Unit also reported that although payments to suppliers *through the auction market* are currently much higher than they were during the first three months of ISO operation, payments made *under RMR contracts* are now somewhat lower.

We have hoped to determine the relative cost of purchasing additional ancillary services capacity from RMR contracts versus the market, and how these two costs have changed over time as more firms obtain market-based rates and the price-cap on ancillary services has been changed from $500/MW to $250/MW. We were unable to obtain data from the ISO on the use of RMR units over any of our three time periods, and were therefore unable to perform this analysis. This is a very important direction for future study that we would like to pursue. This analysis will provide an estimate of the magnitude of the inefficiencies in the market for ancillary services caused by the existence of attractively priced (from the generator's perspective) RMR contracts that can be used to provide ancillary services if there are insufficient bids in the market to meet demand. This analysis will also provide valuable input into process used to determine the level of a damage control price cap on the prices of all ancillary services.

3.3. July 1 to July 13: Some Market-Based Rates but No ISO Price Cap

For the period July 1 to July 13, the ISO decided to procure ancillary services on a zonal basis for all hours and all days. Note that the CONGESTION indicator appears at the top of the price and quantity graphs for all hours during this time interval. Zonal purchase of ancillary services led to very low prices for all ancillary services and very little price volatility North of Path 15. However, South of Path 15, prices were extremely volatile and followed a pattern that has continued to this day.

During this time period, several new generator owners received FERC authorization to receive market-based rates for ancillary services. During this time interval both the $5000/MW and $9,999/MW prices in the replacement reserve market occurred. As a consequence, during the latter part of this time period, the ISO made dramatic changes in its demand for ancillary services across days and hours within the day. For example, for all hours of July 10, the ISO decided not to purchase any replacement reserve. This was followed by several days where the demand for ancillary services both North and South of Path 15 changed hour-by-hour within the day and across days.

Perhaps the most striking feature of this time period is the enormous increase in the variability of bid sufficiency within the day following ISO's decision to change its demand for replacement reserve. However, there were still several periods in the day when bid sufficiencies for replacement dipped below 100% despite extremely large bid sufficiencies during other hours of the day. It is important to note from Figures 3 and 4 that the demand for replacement reserve never exceeded 250 MW from July 11 to 13 in either zone, yet enormous within-day changes in bid sufficiencies occurred. The average value of hourly bid sufficiency in the other ancillary services also increased following July 10. This increase in the average value was due primarily to higher maximum daily values of hourly bid sufficiency, because the daily minimum of hourly bid sufficiency for all ancillary services were still very similar to the values before July 10.

3.4. July 14 to July 31: ISO Price Caps in Effect

During this time period the extreme price volatility in the zone South of Path 15 from July 1 to 13 spread to the zone North of Path 15. During this time period, the ISO purchased ancillary services on a zonal basis only when it anticipated inter-zonal congestion. The CONGESTION variable on these graphs denotes those hours. The price volatility in the zone South of Path 15 was greater than zone North of Path 15. There were many hours when the price of replacement reserve hit the initially imposed price cap of $500/MW and later the cap of $250/MW. (Recall that prices above $250/MW are plotted as $250/MW to preserve the resolution of the plot for prices below $50/MW.) With the exception of the last few days of July, the demands for spin, non-spin and replacement were relatively stable. The demand for regulation was very similar to what it was during the first half of July. Bid sufficiency, particularly for replacement reserve, increased substantially, although there were still a few hours when the number dipped below 100%. As noted earlier, values of bid sufficiency in excess of 1000% frequently occurred, particularly for the zone South of Path 15. (Recall that these values are displayed as 1000% in the Figure). Although average hourly bid sufficiency South of Path 15 appeared to increase for all ancillary services, for many hours during each day, the values are very close to 100% and for a smaller number significantly less than 100%. Values for hourly bid sufficiency slightly greater than 100% indicate that it is very likely that a single bidder can be pivotal in the market in the sense that if the firm's bid were excluded from the market there would be a insufficient bids to meet the ISO's needs.

For several hours during many days from June 11 to July 31, the capacity payment associated several ancillary services was far in excess of the real-time energy price. This occurred despite the fact that the former only requires the generator to be ready to produce, whereas the latter requires the generator to supply electricity. For example, on July 7 during hour 6, the price of spinning reserve capacity South of Path 15 was $240/MW, whereas the price of real-time energy during this same hour was $6.79/MWh. These numbers imply that a winning spinning reserve unit that was called on to produce energy in the real-time market received a total of $246.79 for each MW of capacity used during that hour. A firm that won in the supplemental energy market only received $6.79 per MW of capacity producing electricity during that hour.

3.5. Comparison with Power Exchange and Real Time Energy Markets

In this section we summarize the operation of the Power Exchange (PX) day-ahead energy market and the real-time energy market over our three time periods. As noted at the beginning of this section, in an ideal market for electrical energy, the expected variable profit that a generator could earn from bidding into the Power Exchange should equal the expected variable profit from participating in the ISO's ancillary services markets. The PX price less the generator's marginal cost is equal to the *per unit* variable profit from selling electricity into the PX.

Figure 9 plots the unconstrained PX prices and quantities over our three time periods. The first thing to notice when comparing PX prices to the ancillary services prices in Figures 1 and 2 is relatively small amount of price volatility in the PX price. During the entire month of June prices remain below $50/MWh and in the first two weeks of July, prices were below $100/MWh. Only during the latter part of July did prices approach $150, and only for three hours on July 27, when the price sequence $145.70, $151.10, and $150.71 occurred in Hours 15 through 17.

Another notable feature of the PX prices is the smooth pattern by which prices rise and fall during the day reflecting the changing pattern of electricity demand. In contrast to the ancillary services prices plots in Figures 1 and 2, there are no discrete jumps in prices across adjacent hours in the day from below $1 to more than $250 or from more than $250 back down below less than $1. Even for July 27, the day with the highest price PX in our sample, the PX prices smoothly climbed to their peak at $151.10 and then declined gradually. There were no jumps in prices across adjacent periods of more than $50, a very common occurrence for the ancillary prices in Figures 1 and 2, even for this very high-priced day. For example, the PX price began the day at $30.99 and smoothly rose to $48.00 in Hour 12 and $88.22 in Hour 14 on its way to the peak of $151.10 in Hour 16. The PX price smoothly fell to $32.80 by the end of the day. As is shown the third graph in Figure 9, the daily pattern of demand exactly mirrors the daily pattern of prices.

This clear relationship between increases in the demand and increases in the unconstrained price of electricity throughout the day and across days is consistent across all of the days from June 1 to July 31. This positive correlation between price and demand is consistent with a well-functioning market. As the market demands a greater quantity of electricity, generators must bring on line more expensive generating units to supply that demand, causing the market-clearing price to rise.

Comparing the pattern of PX quantities from June 1 to June 30 to the pattern of PX quantities from July 13 to July 31, we note that the range of demand throughout the day is higher for the period July 13 to July 31. The lowest value of demand for the day is slightly higher than it is for the period June 1 to June 30. The highest value of demand each day was around 35,000 MW in July. In June, this daily peak demand is significantly less than 30,000 MW. The range of PX prices throughout the day is greater for the period July 1 to July 31 than for June 1 to June 30. This is indicative of generator owners having to start the day with higher cost units operating in late July than in June and having to move up to even higher cost generating facilities to meet the much larger daily peak demand in late July versus June.

This same pattern of intra- and inter-day prices can be found in the real-time market as well as in the PX. Figure 10 plots the real-time energy price both North and South of Path 15 for our three time periods. There are only a few time periods (such as a few hours in the late evening on July 18) when there was congestion in real-time and was therefore a difference in the real-time prices between the two zones. Although real-time prices are more volatile both within and across days than the day ahead energy prices from the PX, the real-time prices do tend to move in the same direction as the PX prices both within and across days.

During the month of June, the average real-time energy price was low, reaching a maximum value less than \$100/MWh. The volatility of prices during this time period is significantly less than that for the other two time periods. This is consistent with the view that there was significantly more low-priced capacity available to supply electricity at very short notice in the supplemental energy market during June than in early and late July, when PX demand was higher than in June. Comparing the level of PX demand at the same time of day across the three time periods, we note that the average value of PX demand in a given hour of the day in June is less than that value of demand for July 1 to July 13. The average PX demand for that hour in July 1 to July 13 is less than the analogous value of demand for July 13 to July 31. Consequently, this greater necessity of using higher cost capacity throughout the day in is reflected in higher average real-time prices and significantly more price variability throughout the day. Despite the increased volatility of these real-time prices relative to the PX day-ahead prices across all three time periods, there are many real-time energy prices in the lowest two price ranges given in Figures 7 and 8. The ranges \$150 to \$250 and greater than or equal to \$250, are only hit during the time period July 13 to July 31, and for only a few hours. Price movements across adjacent hours tend to be a little less smooth than in the PX, but we do not see the dramatic jumps in prices across adjacent hours in the day that occur in the ancillary services prices shown in Figures 1 and 2.

Matching up the time scale of the PX prices and real-time prices, we also see that in periods within the day when prices are higher in the PX, prices also tend to be higher in the real-time market. This is consistent with the view that generators expect to earn the same amount of variable profit from bidding into the PX and the supplemental energy market.

For comparison, in Figure 11 we plot the market-clearing price and the demand for replacement reserve south of Path 15 for our three time periods. These are the analogous graphs to Figure 9 for the replacement reserve market. Following our usual convention, we plot any price above \$250/MW as \$250/MW to best reveal price movements in the \$0 to \$50 range. In these plots we see few of the patterns that are present in the PX market. For example, in the final two plots, demand is constant across all hours in the day, yet the range of prices during the day is from \$0.01 to \$9,999. The highest price of \$9,999 occurred in several periods when demand was 250MW, whereas the price of \$5,000 occurred on another day when demand was twice as large.

These replacement reserve market results contradict the usual increasing relationship between market demand and the cost of supplying larger quantities of output. Only during the period from June 1 to June 30, when no firms had market-based rates for replacement reserve, was there a pattern of prices and quantities that is not grossly inconsistent with the pattern of PX prices and quantities. During this period there was very little price volatility and a constant demand.[14]

3.6. Bidding Behavior by Owners of Generating Capacity

To understand the causes of the time series behavior of the prices for ancillary services given in Figures 1 and 2, we performed a preliminary analysis of the bidding behavior of the investor-owned utilities (IOUs)—PG&E, SCE and SDGE—and the new generator owners (NGOs)—AES Corporation, Duke Energy, Dynergy and Houston Industries—for our three time periods. In particular, we investigated the extent to which generators withheld generating capacity from both the day-ahead energy market and the ancillary services market in order to be called on under their Reliability Must-Run contracts.[15]

Figure 12 plots the total hourly bids for each ancillary service by all of the IOUs statewide for each of our three time periods.[16] Comparing the plots for each ancillary service across the three time periods, a uniform increase in the average amount of capacity bid into each of these markets across the three time periods can be detected. This increase in the average amount bid is particularly easy to see for the replacement reserve market. For the period June 1 to June 30, the maximum amount bid was around 3,000 MW, whereas for the period July 1 to July 13, the maximum bid into the replacement reserve market rose to over 5,000 MW. On July 9, the maximum amount bid was over 10,000 MW. For the period, July 13 to July 31, the maximum amount bid ranges from 7,000 MW to 9,000 MW. The other ancillary services follow this same pattern of increased bid quantities over time, although the shift is far less pronounced.

Another striking feature of these graphs is the large variability throughout the day in the amount bid into these ancillary services markets, particularly the replacement reserve market. Variability in bids should be contrasted with the fact, shown in Figures 3 and 4, that the demand for this service is the same for all hours of the day during the period June 1 to July 10. Part of the reason for this volatility is the cumulative nature of bids submitted to the ancillary services markets, although generators do have the option to submit very small or even zero bids to the replacement market even if they submit

[14] Recall that because of missing values of demand for June 6, we plot the value of demand as zero for all hours of the day.

[15] This analysis relies on bidding and scheduled energy data provided to us by the Market Surveillance Unit. Because we received this bidding and energy schedule data very recently, we were unable to perform a more comprehensive analysis. Our results should therefore be considered preliminary. Further analysis and extensions are planned.

[16] Once again the bids for all ancillary services for June 10 were missing from the data provided to us, so the values for all hours on this day were plotted as zero.

large bids to the regulation, spin, and non-spin markets. The fact that the IOUs do just that is clear from the tremendous range of total replacement reserve bids by the IOUs throughout the day in each of the plots. In addition, the fact that the total IOU quantity bid into a lower quality market often falls below the total IOU quantity bid into a higher quality market, indicates that many generators submit bids which reduce the total capacity bid for lower quality services. Later in this report, we will argue that it is precisely this flexibility in bidding capacity into the ancillary services that contributes to the tremendous volatility in ancillary services prices.

A different story of bidding behavior emerges for the New Generator Owners (NGOs), particularly during the time period July 1 to July 13. Figure 13 plots the statewide total of ancillary services bids by hour by the four NGOs for our three time periods. During the month of June the amount bid into the replacement reserve market by the NGOs showed considerably less fluctuations within the day than the amount bid into the replacement reserve market by the IOUs. For the latter part of June there was very little fluctuation in the amount bid into the replacement reserve market.[17] Recall that no firms were allowed to receive market-based prices during this time period. During the period July 1 to July 13, NGO bids for all ancillary services were very stable throughout the day. The pattern of NGO bids into the replacement reserve market is particularly notable in this regard, hovering around 1000 MW until July 8 when it fell to close to 500 MW. Looking at the time path of replacement reserve prices South of Path 15 as shown in the second graph in Figure 11, we see that this reduction in capacity bid by the NGO on July 8 exactly coincides with a continuous period of prices close to $250/MW. Looking at the second graph on Figure 11, we see that the amount of statewide replacement capacity bids submitted by the IOUs dipped to very low levels during this same time period. The events on July 9 can also be viewed from the perspective of Figures 12 and 13. For the both the IOUs and NGOs, the total amount bid in the early hours of July 9 was higher than average for this time period. However, for both the IOUs and NGOs the amount of capacity bid into this market in the later hours of the day was close to the lowest amount bid in during any hour in the period July 1 to July 13. Turning to the second graph, on Figure 11, we see a the spike in the replacement reserve price South of Path 15 of $5,000 for several hours during the time period in which the amount bid by both the IOUs and NGOs into the replacement reserve market was very small.

To investigate impact of capacity withholding from the replacement reserve market on prices in the replacement reserve market in greater detail, in Figure 14 we plot the total hourly bids of IOU capacity South of Path 15 into the replacement reserve market for the period July 13 to July 31. The second graph plots to total hourly bids of NGO capacity south of Path 15 into the replacement reserve market for this same time period. Superimposed on each graph is a plot of hourly prices South of Path 15 for replacement reserves. For almost all hours when this price hit the price-cap in force

[17] Once again, because of missing data for June 10, we plotted the total bids for all hours by the NGOs as zero.

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during that hour, $500/MW or $250/MW, there was a simultaneous trough in the total hourly amount bid by both the IOUs and NGOs into the replacement reserve market. Prices in the replacement reserve market South of Path 15 hit the price cap when both the IOUs and NGOs simultaneously bid less capacity into that market. Turning to the last graph on Figure 6 and comparing it to the hours of very high prices in Figure 14, we see that some of the periods of high prices in Figure 14 are characterized by bid insufficiencies. However, this is not the case for many of the high-priced periods in Figure 14, particularly for the time period in which the $250/MW cap was in effect.

4. **Structural Deficiencies in the Ancillary Service Markets**

As mentioned above, it appears that the markets for ancillary services have not been functioning as competitively as the ones for electrical energy. As the starting point for an analysis of these markets, it is therefore worthwhile to consider the factors that make the markets for ancillary services distinct from those for energy. Once we have identified the potential structural problems with the ancillary services markets, we can try to assess the *long term* impact that these barriers are likely to have on the performance of these markets. In doing so, we can begin to distinguish between transitional problems and problems that are likely to persist.

We have identified nine major factors that have limited competition in these markets relative to energy markets:

1. Some suppliers can receive market-based rates, while others are subject to cost-based rate caps.

2. The demand for ancillary services has been far higher than anticipated.

3. The demand for each ancillary service does not depend on its market-clearing price, and the ISO has limited ability to substitute between services in procuring its system reliability capacity needs.

4. Reliability Must-Run contracts create perverse incentives for bidding into the ancillary services markets.

5. Ancillary services have been purchased on a zonal basis.

6. Dispatch and settlement practices for the provision of imbalance energy are ambiguous.

7. The allocation of ancillary service costs among scheduling coordinators has been flawed.

8. Suppliers from outside of the ISO control area were excluded from the provision of ancillary services.

9. Limitations of the ISO's software have exacerbated these problems.

In the following subsections, we describe each of these contributing factors in more detail. While we are confident that each of these factors has contributed to the current market difficulties, the relative significance of each factor is difficult to determine, and has surely changed over time. Additional analysis of market data currently underway by the Committee will provide further information about the absolute and relative magnitude of these various factors. The Committee believes that this quantitative analysis is necessary before we can offer more definitive conclusions and recommendations for changes in the market design. Nevertheless, we believe that it is desirable to move promptly to correct all of the problems that can be corrected without more definitive study as soon as possible. Recommendations based on our current analysis are given later in this report.

4.1. Asymmetric Regulation of Suppliers

Since their inception in March, the ancillary services markets have never functioned in the manner that was originally envisioned by its designers. Our understanding of the original market design is that it intended that a market process provide price discovery for each reserve product, as well as for energy. However, FERC never granted the incumbent investor-owned utilities (Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDGE)) permission to earn market-based rates for the provision of ancillary services. Instead, each IOU has operated under a cost-based cap on the prices that it can earn in these markets.

In its first three months of operation, the ISO experienced a chronic shortfall of capacity bid into its ancillary service markets (see below) and consistently was forced to call upon units under the terms of reliability must-run (RMR) contracts to provide ancillary services. This was apparently due to the fact that most generators in the market could earn *more* revenue under the terms of their RMR contracts than they could earn under their FERC cost-based price caps. This problem persists, even in the replacement reserve market, because several units receive RMR rates far in excess of the current ISO price caps for these services (see Section 4.4 below).

With the divestiture of much of the gas-fired capacity of both PG&E and SCE, many of the generation units currently eligible to supply ancillary services are now owned by firms that are not covered under the same cost-based rates as the IOUs. In a series of filings to FERC, each of the new owners of this capacity has requested permission to earn market-based rates on the sale of ancillary services.[18] Beginning with its June 30 order, FERC has accepted most of these filings and additionally ruled that replacement reserve was not an ancillary service. This meant that replacement reserve was in fact *never* covered under the cost-based caps. The generation capacity of the major firms in the ancillary services market is given in Table 3.[19]

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[18] See FERC Docket No. ER98-2843-001, ER98-2844-001, ER98-2883-001, ER98-2971-001, ER98-2972-001, and ER98-2977-001.

[19] These figures are drawn from the ISO Generator Master File, which is derived from figures given by the generators to the ISO. We note that there are considerable discrepancies between some of the capacities given below and those reported elsewhere. We encourage stakeholders to work with the ISO to clarify unit capabilities.

Resources	Nameplate Capacity*	10 min AGC Capacity****	30 min AGC Capacity	10 Min Ramp Capacity	60 min Ramp Capacity
Market Based Rates					
AES	3756	461	1382	770	2988
DST	1584	204	612	684	1584
HI	2737	446	1338	684	2555
DETM**	2639	260	780	425	1691
Cost-based Caps					
CDWR	2090	0	0	1621	2042
PG&E***	21607	2527	3649	7538	9913
SCE	12037	180	540	2079	2786
SDG&E	2560	305	915	700	2119
Totals	49650	4511	9600	14629	26318

*Includes QF capacity. Must-take QF and nuclear capacity are not included in the other columns.
**Duke Energy has filed for market-based rates but the request has not yet been granted by FERC.
***Includes PG&E Utility Electric Supply and PG&E Power Generation.
****Rampable capacity figures include hydro capacity. The amount of hydro capacity available for provision of ancillary services at times can be significantly reduced by minimum flow constraints on the hydro systems.

Table 3: Generation and Ancillary Service Capabilities by Firm

Under the current regulatory situation, nearly half of the ancillary-services capacity in the ISO control area is either eligible for, or has applied for, market-based rates, while the majority of the capacity remains under a cost-based cap for the supply of regulation, spinning, and non-spinning reserves. Much of the capacity that is *physically* able to supply ancillary services, therefore has little *economic* incentive to do so. Normally, a market will self-correct to high prices by attracting additional supply, thereby lowering the price. Because of the cost-based price caps, however, many of the sellers in this market can earn no more revenue by selling into this market when market prices are high than when they are low.

The transition from one regulatory regime to another has further restricted supply. On July 1, Duke Energy took possession of 3 generation facilities, but has not yet received permission to earn market-based rates on regulation, spinning and non-spinning reserves. Pending the FERC decision on this application, Duke states that it is unable to bid these units into the ancillary service markets. According to the capacity figures provided to us by the ISO, Duke Energy owns more than 2,500 MW of capacity that it claims it is not able to bid into these markets. This lack of participation of Duke Energy units has exacerbated the supply shortfall for ancillary services in both North and South on Path 15 at exactly the same time other units became eligible for market-based rates for these services.

The IOUs do have some incentive to provide additional capacity to the ancillary service markets when prices are high despite being subject to cost-based caps on their supply of these services. This is because they are large *consumers* of ancillary services. PG&E and SCE are by far the largest purchasers in the PX, and are therefore by far the largest buyers of ancillary services procured through the ISO's daily auctions. These firms therefore have an incentive to defensively bid capacity into these markets in order to lower the price that they have to pay as consumers.

Such defensive bidding may have been discouraged by limited information about ancillary services costs. The presence of cost-based caps on many market participants and the uncertain number of RMR contracts that will be called on to provide ancillary services in any hour make it difficult for market participants to forecast total ancillary services costs for any hour. Even if electricity suppliers knew the market-clearing price for each ancillary service, they would still have a very difficult time forecasting their ancillary services costs for a given hour because the firms do not know what fraction of the total capacity sold in this market was paid the market-clearing price and what fraction was paid according to cost-based caps. In addition, these firms also do not know how many RMR plants will be called and the average RMR price paid. For all of these reasons, ancillary services costs have been are difficult to predict. In addition, the fact that transmission line owners pay for ancillary services procured under RMR contracts, whereas SCs pay for ancillary services provided by these markets, may further dull the incentives the IOUs have for defensive bidding.

The three plots of the time series of total hourly bids submitted by the IOUs for each ancillary services given in Figure 12 is consistent with this defensive bidding strategy. The average amount of IOU capacity bid each hour into all of the ancillary services markets is less in period June 1 to June 30, when all firms received cost-based caps, than that in the period July 14 to July 31, when several NGOs had the authority to receive market-based prices.

A major determinant of the thinness of the regulation, spin, and non-spinning reserve markets is the existence of cost-based caps on the bid prices of the IOUs. Besides the incentives for defensive bidding described above, these firms have little financial incentive to offer additional capacity to these markets when they expect high market prices. The thinness of the replacement market is more puzzling because all generators are eligible for market-based rates. For this market, we believe that the combination of the RMR contracts the current ISO bidding protocol and market-clearing process helps bidders set extremely high prices during certain hours.

The logic for this view is as follows. During the high demand periods within certain days, generators with RMR contracts know with virtual certainty that they will be called under their RMR contracts and receive their RMR payment. Under these circumstances a generator bidding into the ancillary services market will rationally bid significantly more than its RMR payment rate, because the generator knows that if it does not win in the ancillary services market, it will be paid its RMR payment with virtual certainty. Because a profit maximizing generator will bid into the market to achieve the same level of expected variable profit that it can obtain under its RMR contract, its bid price will be significantly above its RMR payment to reflect that generator's assessment of a lower probability of winning in the ancillary services market. Now if other generators are aware that this generator faces this very high probability of being called under its RMR contract, the other firms know that this generator has a very strong incentive to bid a high price into the market. Therefore, regardless of the RMR price these firms face, they also have an incentive to bid a higher price. because they expect the firms with high RMR payments rate to bid a high price. of the expected high priced bid by the firm that knows with virtual certainty it will called under its RMR contract because of conditions in the day-ahead energy market or other information. During these hours, the RMR contracts allow generators bidding into the replacement reserve market to buy a lottery ticket with virtually no risk of losing money, because the RMR contract provides insurance against not receiving revenues in that hour provided by the RMR contract.

4.2. Demand for Ancillary Services is Higher than Anticipated

Many of the other factors listed in this section have contributed to a reduction in the available *supply* of ancillary services. These reductions in supply would have caused fewer problems if the *demand* for ancillary services had not been so much higher than anticipated. There appears to be a consensus that the ISO is acquiring significantly higher levels of ancillary reserves than that reflected in pre-ISO historical norms.

WSCC standards for operational reserves are about 6.5% of system load for spin and non-spin combined.[20] The WSCC leaves the level of regulation reserve largely to the discretion of the operator, but this level has historically been about 3% of load. There is no WSCC standard for replacement reserve, but operators have traditionally kept one hour reserves on hand to replace operating reserves in the event of a serious contingency. A comparison of WSCC standard, or historical, quantities for these three reserve products with the actual quantities of regulation, spin and non-spin purchased by the ISO (Table 4) shows that the ISO often requires more than twice the amount of these services than has

[20] The WSCC requires spinning and non-spinning reserves total 5% of hydro and 7% of non-hydro generation output.

historically been the case.[21]

[21] Scheduled generation here refers to the total energy scheduled by generation *within* the ISO control area. This is an approximation of the actual schedule for which the ISO must acquire services.

			June				July	
	hours 1-6	Hours 7-12	hours 13-18	hours 19-24	Hours 1-6	Hours 7-12	hours 13-18	hours 19-24
Avg. scheduled generation (excludes imports)	16356	19304	20913	19369	17624	22978	28160	24340
3% of scheduled load	491	579	627	581	529	689	845	730
Avg. regulation required	1368	1675	1281	1776	1674	2131	1828	2447
7% of scheduled load	1145	1351	1464	1356	1234	1608	1971	1704
Avg. spin and non-spin required	1204	1428	1510	1424	1726	1850	2037	1915
Avg. total ancillary services required	3572	4103	3791	4200	4021	4621	4616	5043

Table 4: Ancillary Service Purchases During June and July 1998

Table 4 reveals that regulation accounts for most of the unexpected increase in ancillary service purchases. This is especially true during the shoulder periods (hours 7-12 and 19-24) when both generation and load quantities change rapidly. ISO operators state that a one factor behind the need for increased regulation capacity is the current ISO protocol for moving up the real-time energy bid stack. It is our understanding that, at any point in time, the operator must decide whether to move up or down the real-time energy bid stack or simply use more regulation capacity to meet unexpected fluctuations in electricity demand relative to its schedule. The current ISO protocol requires that sufficiently large amount of upward or downward system-wide regulation capacity be in use before a decision is made to move up or down in the real-time energy bid stack. The operator often does not know, with sufficient certainty on a day-ahead basis, if this movement will be in the upward or downward direction. Consequently, the ISO must procure an increased amount regulation capacity. Another potential cause of the increased demand for regulation is that generating schedules take the form of discrete hourly steps. Generators must pay for any deviations from these step function schedules at the real-time hourly imbalance price. During these shoulder periods the level of imbalances can be extreme due to the sharp increases in consumption and output that are necessary to reach the next hourly scheduled "step" for each unit a generator owns. A final potential reason for this increased demand for regulation by the ISO has to do with how it pays for instructed versus uninstructed deviations. As discussed earlier, uninstructed deviations are settled at the average of the six 10-minute prices for each hour. Instructed deviations from schedule are settled at the 10-minute price relevant when the instruction is given to the generator by the ISO. This asymmetry in prices at which different types of deviations from schedules are settled can create incentives for uninstructed over-generation during high-priced 10-minute periods and uninstructed under-generation during low-priced 10-minute periods. We would like to determine if any of these three potential reasons for an increased demand for regulation capacity is actually relevant. If any one is relevant, we would like to quantify how much larger it makes the demand for regulation.

The ISO's purchase of regulation capacity at levels that by itself sometimes exceed the WSCC requirements for *all* ancillary services has not been offset by a decreased purchases of any other ancillary services. The ISO has continued to purchase spin and non-spin at a level *over* 7% of load. Even within the two spinning reserve services, the current practice, as described below, is *not* to buy more of one service and less of the other when one is considerably cheaper.

Many aspects of the market design have conspired to create an increased need for reserves. As the above discussion makes clear, the task of acquiring ancillary services is much more complicated for a third party in the context of a competitive market than it was for vertically integrated utilities. Particularly within the context of the California market design, generators are allowed to deviate from their schedules in real-time for both economic and non-economic reasons, yet the ISO must still maintain system reliability. It is hard to see how, under this market design, the ISO can purchase less ancillary services capacity than was procured when the grid was centrally dispatched by a single IOU and certain units were used to provide a load-following service, a product not available in the current market design. However, the optimal quantity of regulation or any other ancillary services capacity to purchase in this environment is unknown. We note, as well, that the ISO does not bear the final cost of the reserves that it acquires. These are passed on to the users of the system. However, as a fledgling institution, the ISO has a very strong incentive to avoid serious reliability problems. The thorny problem of providing operators the incentive to both minimize costs and ensure adequate reliability is a long-standing one in the electricity industry.

4.3. Ancillary Services Are Not Procured Rationally

While the *amount* of ancillary services that the ISO has procured has been a source of the high prices seen today, the *manner* in which these services are procured is also a major contributing factor. The ISO has been purchasing most services according to a rigid standard, not allowing for any substitution between services within that standard. The quality of ancillary services can, with some qualifications, be characterized as hierarchical, with regulation being the highest quality product, followed by spin, non-spin, and lastly, replacement reserve. One would not expect a rational buyer of ancillary services to purchase a lower quality ancillary service at a given price if a higher quality service is available at a lower price. However, it has usually been the case that the market-clearing prices for "inferior" ancillary services such as spinning reserve have exceeded those for "superior" services such as regulation. There are many cases in which the difference between these inverted prices have been extreme (see Table 5). Although this inflexible purchasing practice can be viewed as consistent with the ISO tariff, it is our understanding, based on discussions with ISO consultants and staff, that it is *not* consistent with earlier versions of the market design. It was intended that the ISO be given some flexibility to act as a "rational" buyer of ancillary services.[22] In addition, Section 2.5.8 of the ISO tariff contains the following two sentences: "The ISO shall operate a competitive Day-Ahead and Hour-Ahead market to procure Ancillary Services. It shall purchase Ancillary Services capacity at least cost to End-Use Customers consistent with maintaining system reliability."

Month	June		July	
	SP15	NP15	SP15	NP15
Hours when at least one inferior service had a higher price than a superior service	90%	83%	73%	91%
Hours when at least one inferior service had a price more than $50 greater than a superior service	10%	8%	30%	7%

Table 5: Frequency of "Inverted" Prices

Under the implementation of the market, all the bidders *know* that the ISO operators will adhere to rigid procedures when acquiring ancillary services. Therefore, the bidders know with relative certainty exactly how much of each service the ISO will need to acquire. In addition, the participants know that the ISO's demand for each service does not in general depend on the market-clearing price. This knowledge, combined with detailed familiarity about the supply conditions in the market, all too often has allowed firms to accurately predict exactly when their capacity *must* be purchased by the ISO. In other words, firms know when their capacity is pivotal to the market. Under these conditions, the ISO must accept the capacity offered by these firms at any price (subject to price caps). Thus, current purchasing practices have produced a very

[22] See "Response of the California Independent System Operator Corp. and the California Power Exchange Corp. to Request for Additional Information." FERC Docket Nos. ER96-1663-003 and EC96-19-003. May 20, 1997. In particular Attachment IV, "Priority Pricing of Ancillary Services," by Robert Wilson.

predictable and inflexible demand for ancillary services. This is hardly "the market" in operation. In a true free market setting, buyers would substitute services, negotiate contractual protections, and encourage other suppliers to step forward; and bidders would not be subject to cost-based rate caps.

4.4. Perverse Incentives Created by Reliability Must-Run Contracts

Reliability must-run (RMR) contracts were designed to provide a means for correcting for the locational market power of certain generation resources. Such generation, if purchased under market protocols that required power to be purchased from the zone in which it is needed, could demand a considerable premium over marginal cost since there is often no viable substitute for that generation short of curtailing load. In order to avoid the abuse of such market power, RMR contracts were created for the bulk of the gas-fired generation capacity located within California. RMRs were originally envisioned as "call" contracts to which the ISO could turn to procure generation from certain resources at a pre-negotiated and, in theory, cost-based price.[23] This concept was argued to be a satisfactory means of mitigating local market power, provided that there was no market power in the *overall* (non-local) market.

In practice, the market has been negatively impacted by RMR contracts through both the overuse of some contracts and the underuse of others. It could be argued that, given current price caps, the ISO may have been better off with *no* RMR contracts than it is with the contracts in their current form. As mentioned above, several contracts specify extremely high availability payments, sometimes in excess of $4000. The owner of such units can collect the most revenue for these resources by having the RMR contracts on these units invoked as much as possible. These expensive units therefore have little incentive to bid into the market at times when there is a reasonable probability that they may be called upon under RMRs. This is especially true for units subject to either FERC or ISO imposed price caps. If there were little or no chance that a given unit will be called upon under its RMR contract, the unit's owner loses little by bidding the unit into the market. However, the times at which these units are most likely to be called upon under its RMR contract are exactly the times when they are most needed in the market--high demand hours. This was widely acknowledged to be a significant problem during the earliest months of market operation. The problem has now been offset somewhat by the fact that market-based rates have of late been extremely high. As discussed earlier, we would like to evaluate the severity of this effect under the current market conditions.

[23] See Section VII of Joskow, P., Frame, R., Jurewitz, J., Walther, R., and Hieronymous, W. (1996), "Report on Horizontal Market Power Issues", Supplement of the Southern California Edison Company and the San Diego Gas & Electric Company to Application for Authority to Sell Electric Energy at Market-Based Rates Using a Power Exchange. Federal Energy Regulatory Commission, Docket No. ER96-1663-000. See also Jurewitz and Walther. "Must-run generation: can we mix regulation and competition successfully?" *The Electricity Journal*, 10(10): 44-55.

This problem is exacerbated by the extremely high level of some of the pre-set payments. The RMR rates were meant to include recovery of some fixed costs, in addition to the marginal cost of operation. However, the rate of fixed cost recovery was determined by dividing the total annual fixed cost by the expected number of hours under which the unit would be called under an RMR. In fact most units have been called upon to provide generation under RMR contracts far more frequently than had been forecast when those rates were negotiated. This means that some units can recover far more than their total annual fixed costs through RMR payments.[24] Later in this report we make recommendations for modifications of the RMR contracts that help to alleviate these reduced incentives for participation in the market caused by this RMR payment scheme.

Figure 15 contains a plot of the capacity under RMR contracts as a function of their payment if they are called to produce electricity under the terms of their RMR contract. This payment is the sum of the Reliability Payment Rate plus the fuel cost, operating and maintenance cost and emission cost per MWh. This graph also plots the estimated marginal cost curve for generation from these RMR units.[25] Because there are several RMR contracts with payments in excess of $4000/MWH, we have truncated the graph at a payment rate of $1000/MWH to illustrate the divergence between marginal generation cost of the supply curve for RMR energy. Extending the graph to $4500 yields approximately 500 MW more in RMR capacity, resulting in a total of over 14,000 MW of statewide RMR capacity. Given this RMR capacity figure, if the ISO were able to call on RMR units for both economic and reliability reasons it would have a ready source of additional supply during those periods when the demand for ancillary services is high. This large source of supply at known prices would discipline any attempts by generators to exercise market power by bidding high prices into the ancillary services markets.

Capacity withholding and RMR payments

We were able to perform a preliminary analysis of the extent of capacity withholding in this market. For each hour and each generating unit we computed the following two indicator variables. The first indicator variable was set equal to one if the

[24] Under the current Type A RMR contracts, which all generators started the market with, the "availability" payment, the mechanism for recovery of fixed costs, is paid each time the generator is called under the RMR contract. The current Type B RMR contract pays the generator's entire fixed cost up front, but imposes significant penalties on the generator for any market revenues it earns in excess of its annual total costs. If the ISO calls the unit more times than specified in the contract, it pays a "pre-negotiated" penalty variable cost rate. We understand from the ISO that, under the initial contracts, these rates are significantly greater than the unit's contractual variable cost to compensate for the increased wear and tear from these additional hours.

[25] The estimates of marginal cost include fuel cost and variable O&M. These estimates are taken from Borenstein, S. and J. Bushnell, "An Empirical Analysis of the Potential for Market Power in California's Electricity Industry," University of California Energy Institute. PWP-044, May 1998.

unit was scheduled to provide a non-zero amount of energy. The second indicator variable determined whether a unit submitted a bid beyond the "RMR placeholder bid" level to any of the ancillary services market during that same hour.[34]

The two hourly generating-unit-level indicator variables where combined into a single market participation indicator variable as follows. If either the scheduled energy indicator variable or the ancillary services market indicator variable was equal to one, we set the market participation variable equal to one. Using this procedure, we computed this market participation variable for each generating unit in the ISO's Participant Master File for each hour from June 1 to July 31. We then computed the fraction of total hours in each of our three time periods that the value of this market participation indicator variable was equal to one for each generating unit. For most of the generating units this fraction was equal to or very close to one. However, for a number of units the value of this fraction was very small for the three time periods, and even equal to zero for some time periods. On further investigation, we found that the vast majority of these units with small values of this market-participation fraction had RMR contracts in force.

There also appeared to be an inverse relationship between the value of the RMR payment and the value of this market-participation fraction. To investigate this hypothesis more rigorously, we obtained the reliability must run payment level for each generating unit from the Market Surveillance Unit of the ISO. For each of our time periods, we then regressed the value of an RMR unit's market participation fraction on the value of its RMR payment level. For the first two time periods we did not find any statistically significant correlation between the level of the RMR payment and the market participation fraction for that unit. However, for the third time period, from July 13 to July 31, we found a statistically significant negative correlation between the level of the RMR payment and that unit's market participation fraction.

Although they are far from definitive, our regression results suggest that units with particularly high RMR payment rates are less likely to either have day-ahead energy scheduled or bid into any of the ancillary services markets (beyond the placeholder bid level). We should also caution that our results are still preliminary, as well as conditional on the accuracy of the RMR payment data, energy schedule data, and ancillary services bid data made available to us for analysis. With this caveat, our results suggest that high RMR payment rates undermine the incentives for a generating unit to participate in the day-ahead energy markets and/or the ancillary services markets.

[34] From our conversations with staff at the Market Surveillance Unit we were told that generators wishing to be called to provide ancillary services under their Reliability Must Run contracts were asked to submit very small non-zero "placeholder bids" on the order of 0.0x MW, where x is some number between 1 and 9. Consequently, in constructing our indicator variable for whether or not a unit bid into the ancillary services market we set this indicator value equal to one only if the unit bid above this placeholder level into any one of the four ancillary services markets. Consequently, all units that submitted these "placeholder bids" for all four markets were given a value of zero for this indicator variable.

RMRs and the mitigation of local market power

The second difficulty with the current implementation of RMR contracts is that the protocols allow firms to continue to exercise market power.[27] If these contracts were truly "call" options with a pre-negotiated strike price, the ISO would be able to purchase ancillary service capacity at this price whenever the market price rose higher than the contract price. The current practice, however, is to call upon RMR units only when those same units cannot be acquired, at any (non-capped) price, from a "market." Currently, some of these units are successfully bidding "market" rates far in excess of their RMR rates, and thus presumably far in excess of the (long run) marginal costs upon which the RMR rates were based. These contracts therefore seldom mitigate market power. Instead, the usual result under the current implementation of RMR contracts is that the ISO gets to purchase under the RMR rate only when that rate far exceeds what would otherwise be the market clearing price.[28]

As mentioned above, some units have been able to earn market prices far in excess of the RMR rates. This may in part be due to the fact that the market through which their capacity is acquired is small enough that these units enjoy some market power. When the market is defined over a smaller region, such as southern California, the number of competitors is reduced and extremely high bids, such as $5000, can still be successful. In a broader market, such a unit might be outside of the set of successful bids and therefore have to be called under RMR. The PX, for example, does not hold a separate auction for energy in San Francisco where a single unit can be pivotal, bid any price, and be considered "in" the market. Ancillary services, however, are sometimes purchased on a zonal basis (see the subsection immediately below) and some firms likely have market power over the southern zone. These firms can therefore exercise their market power in this zone, have their capacity selected at high prices, and avoid being called under an RMR.

[27] A third potential difficulty with RMRs, as they are currently constituted, is the potential incentive problems that may arise from the interaction of units with "A' and "B' type contracts. We do not have enough information at this time to evaluate this problem, but would like to monitor its potential impact on the market.

[28] Some market participants would clearly prefer that the ISO be forced to accept high bids before turning to RMR units, arguing that the "market" should be used before RMR units are called. However, this view rests on an artificially narrow notion of the "market." Buyers with urgent and inelastic needs rarely rely entirely on a spot market for their needs; a true "market" includes a variety of contractual forms, from spot markets to long-term contracts to vertical integration.

4.5. Zonal Purchase of Ancillary Services

An additional limitation on the competitiveness of the ancillary service markets has been the division of the state-wide market into smaller sub-regions. The ISO tariff Section 2.5.4 states that "For each of the Ancillary Services, the ISO shall determine the required locational dispersion in accordance with ISO Controlled Grid reliability requirement." This tariff provision itself is a potential problem when there is market power within a given zone. We address this point below. In addition, the ISO has on occasion purchased ancillary services on a zonal basis, even when the transmission path connecting the northern and southern zone has *not* been congested. This has been done either out of concern over the *potential* for congestion on Path 15, or because congestion on other paths within the ISO control area has limited the ISO's ability to "transport" ancillary services within its control area. For example, a 1000 MW statewide need for replacement reserve might, absent congestion, be provided from 800 MW of generation in the North and 200 MW of capacity in the South. If, in this example there were congestion, or a forecast of congestion, the ISO would instead purchase 500 MW of replacement capacity in the North and 500 MW in the South. If supply is tight in the southern zone, the remaining suppliers may enjoy local (or zonal) market power. As noted above, this split purchase is sometimes done even when there is no congestion on Path 15. Thus, on occasion, the ISO's ancillary service prices have varied significantly by zone, even when the imbalance energy price has been the same for each zone.[29] In short, even if the ancillary service markets can be made workably competitive on a state-wide basis, they may remain vulnerable to market power when conducted on a zonal basis. We propose an alternative state-wide auction later in the report.

4.6. Ambiguous Dispatch Practices for the Provision of Imbalance Energy

As described in Section 2, the market design implied by the ISO tariff indicates that suppliers of *all* ancillary services are also eligible to earn the imbalance energy price if they are called upon to supply energy in addition to reserve potential. Bidders into the PX and these markets were expected to weigh potential earnings from both capacity and imbalance energy sales in making their decision about which market to participate in.

However, it is virtually impossible for suppliers of regulation reserve to set or earn the imbalance energy price due to the fact that their output levels are constantly increasing and decreasing, creating a net imbalance that is often near zero for the hour. A supplier of regulation energy is frequently required to vary its output both upwards and downwards. Imbalance payments, however, are based upon the *net* imbalance during a

[29] The ISO is also currently not able to utilize transmission capacity for ancillary services, even when it might be economic to do so. Because of this, transmission capacity is sometimes allocated to ship energy between zones with very small energy price differences, while these same zones may at the same time experience major ancillary service price differences.

given time period.[30] Thus for a provider of regulation energy, the net imbalance usually far understates the true contribution that the generator is making to the system.

This problem contributed to the shortage of capacity bid into the regulation market during the early months of its operation. On May 21, the ISO instituted the REPA mechanism to pay suppliers of regulation energy an amount based upon the total (up and down) adjustable capacity they provide during an hour. Bid sufficiency in the regulation market has improved since the implementation of the REPA payments, but still remains below 100% in many hours.

Suppliers of other ancillary services have not always been dispatched for the provision of imbalance energy, even when they have the lowest available energy bid. At times, ISO operators have judged that the reserve potential provided through these ancillary services should not be reduced by calling upon these units to provide energy. This usually occurs during high demand periods in which concerns about sufficient operating reserves are the highest. ISO operators have indicated that this practice is consistent with the original spirit of the technical design of the ancillary services markets and is necessary for compliance with WSCC reserve standards. While this practice may be the most prudent one from a reliability standpoint, the result is that suppliers of reserve capacity have difficulty predicting their potential revenues. A provider of spinning reserve, for example, that has a very low energy price may or may not be dispatched to provide energy. This was a frequently heard criticism of the ISO's operating procedures in our telephone interviews and public meetings.

The ambiguities in the usage of units providing reserve capacity are exacerbated by compliance problems. ISO operators have indicated that several units that are receiving reserve payments are conducting uninstructed increases in their output. These units thereby collect the imbalance energy price in addition to their reserve payments, even though they are supposed to be providing only reserve. There is evidence that the current protocols for monitoring and punishing non-compliance have not been sufficient to deter such behavior.

Another ISO dispatch practice that several market participants have protested against is the acquisition by the ISO of reserves and energy from outside of the ISO control area through a process of negotiation. The ISO operators have at times relied upon negotiated agreements with neighboring control areas when the operators have received either a shortfall or an excess of supply through the standard market processes. The ISO states that it has the right to turn to negotiations with outside areas to fill areas of need not met by its markets. Some stakeholders claim that the conditions under which these negotiations occur are sometimes not true shortfalls and that this process discriminates against firms inside the control area who do not receive the same

[30] The software that tracks these imbalances calculates them every 10 minutes while a generator providing regulation may be revising output far more frequently.

consideration for negotiated agreements. We are not familiar enough with the relevant tariff protocols to judge the veracity of these claims, but we do observe that some degree of consumer flexibility on the part of the ISO is an effective defense against the exercise of market power. At the same time, it would be desirable to increase the transparency of the decision process of the ISO's recourse to outside negotiations. A possible alternative discussed in Section 5 is a set of longer term agreements under which the ISO might acquire resources and for which suppliers both within and outside the ISO control area could compete.

4.7. Flawed Allocation of Ancillary Service Costs to Scheduling Coordinators

Another distortion of the ancillary service market is the manner in which the ancillary services are paid for. Currently, all ancillary service costs are allocated pro-rata according to *day-ahead* schedules. Thus, the cost burden for reserves is shared according to the level scheduling coordinators *say* they are going to use the system, and not according to the level that they *actually* use the system. The current billing practice gives firms an incentive to under-schedule, because doing so reduces the amount of ancillary services the firms have to pay for.

Figure 16 illustrates the difference between the day-ahead scheduled daily load and the hour-ahead scheduled load for the same day. Day-ahead loads schedules have consistently understated the hour-ahead schedules all weekdays except Mondays. The magnitude of this difference has been increasing as ancillary service prices have continued to stay at the currently high levels (note the scale on right-hand axis).

It was originally thought that the creation of a replacement reserve product would help deter under-scheduling. The tariff intended that replacement capacity would be paid for only by the firms who produce less generation than they had scheduled, thereby placing the cost burden to the system from under-scheduling onto the firms that had caused the problem. However, software shortcomings have prevented the implementation of this intent. Additionally, under-scheduling increases the amount of replacement reserve that the ISO needs to procure. So a firm can potentially reduce its own ancillary service payments *and* increase its sales of replacement reserves by scheduling less than its anticipated demand.

4.8. Exclusion of Suppliers from Outside of the ISO Control Area

Until August 6, the ISO could not accept ancillary service bids from any supplier located outside of the ISO control area, due to limitations in the bidding software. This represents a significant reduction in the pool of potential suppliers to the ancillary services market. By comparison, the share of *energy* scheduled in the ISO system that has originated from outside the ISO control area has at times reached up to 20%. On

August 5, some of these barriers were removed, and suppliers from outside the ISO have since been able to bid into all ancillary service markets except regulation. The regulation market will remain open only to suppliers from within the ISO due to the more demanding physical requirements of that service. In addition to ISO software constraints, several municipal utilities also face contractual barriers to providing ancillary services to the ISO.[31]

It is important to note, however, that suppliers from outside the ISO control area could have an *indirect* impact on the ancillary services market. In the absence of other distortions, we would expect to see suppliers from inside the ISO control area respond to high ancillary service prices by shifting capacity from the PX (and other SCs) into the ancillary service markets. This would in turn increase the energy price in the PX and, absent congestion, draw increased supply from *outside* the ISO. As with the energy market, transmission limitations and high out-of-ISO demand can limit the amount of capacity available for export into either the ISO or the PX.

4.9. Other Software Difficulties

Several software problems have been identified either by the ISO or market participants. It is our understanding that corrections to most of these software problems are universally desired and therefore not controversial, although the priority given to the various software fixes is still a subject of debate. These problems are listed below. A description of each of these problems provided to us by the ISO is attached as Appendix A of this report.

It is important to note that confusion *about* many of the software issues has impacted the market almost as much as the problems themselves. We advise that the ISO establish an outlet through which stakeholders can notify the ISO of software problems and from which they can receive information about the progress of software fixes. This would ideally include clear notification of when and how the various problems have been corrected. This outlet should be an easy to access and transparent, and could perhaps be added to the ISO web site. In addition to progress reports, the ISO could use this outlet to help establish priorities amongst stakeholders for various software fixes. Many of the comments and complaints of market participants that have been received by the Market Surveillance Committee could have been addressed by this kind of procedure.

1. Inability of the Real-time Dispatch Software (BEEP) to Track Operator Dispatch Instructions
2. Mishandling of Downward Regulation in Sequential Ancillary Service Evaluation
3. Inadequate Verification of Eligibility of Ancillary Service Bids

[31] Several municipal utilities have signed interconnection agreements with neighboring (or surrounding) IOUs that include both monetary and operational constraints which make it difficult for these firms to export ancillary services through those interconnected transmission facilities.

4. Lack of Coordination between Congestion Management and Ancillary Services Management Software
5. Settling Ancillary Service Responsibility based on Scheduled rather than Actual Load
6. Improper Settlement for Replacement Reserves
7. Lack of Proper Coordination Between ISO's Dispatch and Automatic Control Software
8. Lack of 10-Minute Real-time Price Information
9. Failure to Track Uninstructed Deviations using Reserved Capacity
10. Improper Payment for Uninstructed Deviations
11. Ignoring Impact of Ancillary services on Congestion
12. Lack of Explicit Requirement for Downward Regulation

5. Recommendations

In this section, we list a number of options for addressing many of the problems described in Section 3. We focus here on policy and market design modifications that should be viewed as additional proposals beyond the correction of the various software-based problems that have impacted the market. The benefits of some of these proposals, such as a state-wide auction for ancillary services, will be further illuminated once we have completed our broader empirical analysis of the performance of these markets using the data obtained from the ISO's Market Surveillance Unit. The impact of several of the proposals may also depend upon the implementation of others. For example, we do not recommend giving to all participants the right to receive market-based rates unless the ISO has the right to impose a damage-control price-cap that will permit it to reject excessive bids. This price cap makes explicit the usual right that all buyers have, and the ISO should be no exception, to refuse to purchase at excessive prices. The ISO should be able to raise or lower the cap as it sees fit based on periodic review of the performance of the markets. We feel that all of these proposals represent steps in the right direction toward a better functioning market.

- Implement "rational" purchasing practices for ancillary services that allow the ISO to substitute cheaper superior services for more expensive inferior services in its procurement of ancillary services.
- Revise RMR protocols and rates so that generating units with RMR contracts no longer have the incentive to withhold capacity from the day-ahead energy market and ancillary services markets in order to be called under their RMR contracts. This could involve creating a new class of true option contracts to replace some RMRs.
- Grant market-based rates for ancillary services for all market participants, assuming the ISO retains the authority to impose a damage control price cap. This could also be accompanied by, or contingent upon, the commitment of some of the capacity of PG&E to contracts for differences for the provision of ancillary services
- Retain a damage control price-cap on all ancillary services that can be raised or lowered at the ISO's discretion, regardless of what decision is made on granting all firms market-based rates for all ancillary services
- Run the auction for ancillary services on a state-wide basis. If the state-wide market-clearing prices leaves a shortfall of supply in a given zone, use RMR contracts to make up the shortfall
- Revise scheduling and/or energy imbalance protocols to help reduce the need for regulation capacity.

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5.1. Adopt Rational and Transparent Purchasing Practices

No matter what other regulatory or procedural changes are made to these markets, the rigidities in the current protocols for purchasing ancillary services should be removed. We recommend that the ISO adopt the common sense rule of applying a bid to supply a higher quality ancillary service to the provision of a lower quality ancillary service when doing so reduces purchase costs. Thus, the ISO would have the discretion to substitute extra regulation capacity for spin capacity, if this unused regulation capacity was bid in at lower prices than the spin capacity. It could also substitute unused regulation or spin capacity for non-spin capacity, if either of the first two services were bid in at lower prices than non-spinning reserve. Finally, any unused regulation, spinning and non-spinning reserve capacity could be purchased instead of replacement capacity if any of these three services were offered at lower prices than replacement reserve capacity.

Although there are several complications associated with implementing rational purchasing within the context the current ISO protocols, all of the market participants we talked to both in our telephone interviews on August 10 and at the open meeting of the Market Surveillance Committee on August 12 supported allowing the ISO this sort of discretion in procuring its ancillary services requirements.

One complication associated with implementing this rational buyer strategy for the ISO is that the *energy* payments made to generators for regulation capacity differ from those made to generators providing other ancillary services. Suppliers of regulation are compensated through the REPA mechanism because they cannot receive the real-time energy price for electricity supplied from their units. We are currently studying various proposals for making the ISO a more rational buyer of ancillary services in a manner consistent with statements from the ISO tariff quoted in Section 4.3. In the meantime, a few straightforward changes in the ISO's ancillary services procurement protocols can move it significantly closer to rational buyer market outcomes.

A straightforward method for introducing some buyer rationality into the ISO's purchasing process would be to impose the requirement on market participants that all bids for superior services also to apply to the provision of inferior ones. For example, if a firm bid a block of capacity at a given price into the spinning reserve market, that block is also eligible to provide non-spin and replacement reserve from this capacity if it is not taken in the spinning reserve auction. It would be rolled over to the bid stack for any inferior product, at the same price that it had been offered for spin. Alternatively, the ISO could just buy more spin, if it were cheaper than non-spin, and substitute it for non-spin. In either case, the cost to the ISO is the same. However, since it is reasonable to assume that, for a given unit, the cost of providing these services is declining across the hierarchy (regulation, spin, non-spin, replacement), a generator offering spinning reserve capacity at price of $10/MW would prefer to receive that price for providing non-spinning or replacement reserve.[32] It would therefore improve the economic efficiency of the

[32] This assumes that the unit will be dispatched in the real-time energy bid stack according to its energy bid

ancillary services markets to let that unit provide the inferior service at the price offered for the superior service. Imposing this requirement on bids submitted by each generating unit to the four ancillary services markets, would guarantee that the four total hourly bid quantities plotted in Figure 12 and 13 would never cross. The total hourly amount of regulation bids submitted would always be less than the total hourly quantity of spin bids, and so on. The total hourly amount of replacement bids greater than that value for all other ancillary services.

Given that the cost of supplying these services should decline as one moves from higher to lower quality services, firms would ideally submit *lower price* bids to the ISO for the supply of a lower quality service after that capacity lost at a higher price in the auction for the higher quality service. For example, if a generator submitted 100 MW that was not accepted for the supply of regulation at $50, and the capacity is then rolled over into the spinning reserve market, that generator would want to lower the price of that unit in order to increase its chance of earning some revenues from it in the lower quality markets. To capture this aspect of bidding based on the cost of supply, the ISO should allow firms to lower the price of their bids if those bids are rolled over into a market for a lower quantity service. However, we recognize that allowing for this possibility would significantly increase the number of prices that each unit would be required to submit. In particular, there would be a bid price for capacity explicitly bid into each market and a bid price for capacity that was bid into a higher quality market not taken and therefore available for a lower quality market. Rather than increase the number of bid prices each unit can submit, we feel that the much of the increase in market efficiency made possible allowing bid prices lower quality service markets for capacity not taken in higher quality services can be captured within the constraints of the current ISO bid software by imposing the requirement on each generating unit that the capacity price bid for a lower quality service may not exceed the price bid for the next higher quality service. Under this restriction, all capacity not taken in a higher quality product auction will be available to be taken in a lower quality auction at a bid price that is less than or equal to price that it lost at in the higher quality auction.

with the same probability regardless of whether the capacity is used for spin, non-spin or replacement reserve. The assumption of an equal probability of being dispatched in the real-time energy market across the spin, non-spin and replacement capacity markets is a necessary condition to claim this improvement in economic efficiency.

These two changes to the ISO's purchasing protocols are summarized below.[33]

Rational Buyer Protocol

1. **For each generating unit, the total quantity of capacity bid for the supply of each ancillary service cannot decrease as a quality of the ancillary service product decreases.**

2. **For each generating unit, starting with the highest quality ancillary service product that has a non-zero capacity bid, the bid prices associated with that ancillary service product and all lower quality ancillary service products must not increase as the quality of the ancillary service product decreases.**

Thus for a generating facility offering capacities, $q_{reg}, q_{spin}, q_{non}$ and q_{repl}, for the supply of regulation, spin, non-spin, and replacement, respectively, the ISO should require that $q_{reg} \leq q_{spin} \leq q_{non} \leq q_{repl}$ and that $p_{reg} \geq p_{spin} \geq p_{non} \geq p_{repl}$, where p is the bid price for these respective services from that generating unit. This protocol change would require a simple bid consistency check on a unit-by-unit basis for the satisfaction of these inequalities before the data enters the ISO's current market-clearing process for the ancillary services markets.

In order to implement meaningful substitution between reserve services, the payment mechanisms for these services must be consistent. Ideally, this would mean that every firm would be eligible for market-based rates, thereby rendering REPA unnecessary. Although the rational buyer requirement on generator bids could still be implemented *if* REPA remained a component of compensation for regulation providers, we do not recommend this course of action. The REPA simply substitutes an administratively determined additional payment to winning bidder in the regulation auction. We instead recommend that REPA should be eliminated, the rational buyer requirements on generator bids imposed, and market-processes be allowed to set the price of providing regulation, subject to a damage control price cap.

In addition to adding flexibility to the ISO's purchasing protocols, it is important that these protocols be transparent to market participants. Bidders into these markets must be able to formulate accurate expectations the revenue they can expect to earn from a given bidding strategy in order for the market to operate effectively. This is especially true for the provision of imbalance energy. As discussed earlier, generators providing spin and non-spinning reserve are uncertain of the mechanism used to dispatch them in

[33] This change in bid protocols will allow the ISO to retain it current market-clearing processes yet increase the frequency of hourly ancillary services prices that have higher-quality services priced higher than the lower quality services. This rational buyer protocol should therefore only be in effect until the appropriate fully rational, total cost-minimizing ancillary services procurement process can be designed and implemented.

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the real-time energy market, because the operators often skip over energy bids from spin and non-spin units in the real-time energy bid stack. The ISO should clarify, to the greatest extent possible, the conditions under which spinning and non-spinning resources can be called upon to provide imbalance energy. At the same time, the ISO may wish to consider whether it is possible to reduce the overall need for the various ancillary services, especially replacement reserve. No matter what is viewed to be the appropriate need for and usage of ancillary services, it is important that the protocols for usage are clear to all market participants.

One method the ISO may wish to consider for resolving the ambiguities surrounding the usage of capacity reserves for the supply of imbalance energy is the application of a fixed "adder" to the energy price of generation units providing a given service. Each ancillary service could have a different adder value, set to approximate the opportunity cost of replacing that reserve. This value could be set at the day-ahead market-clearing price for that hour for the capacity of that ancillary service, or there could simply be fixed adder for all hours of the day for each ancillary services energy bid. To take a concrete example, suppose the day-ahead price of non-spinning reserve capacity was set at $10/MW. A spinning reserve unit that had won in the day-ahead capacity auction would then have $10/MWh added to its real-time energy bid when it is placed in the real-time energy bid stack. Suppose this facility's real-time energy bid was $20/MWh, then its price in the real-time energy bid stack would be $30/MWh, and it would only be dispatched if the real-time energy price exceeded $30/MWh, not its bid of $20/MWh. The use of this adder places a dollar value on the opportunity cost of spinning and non-spinning reserve units in the real-time energy bid stack. The replacement reserve capacity would have no adder in the real-time energy market under this scheme. This scheme has the benefit that firms bidding into the spinning and non-spinning reserve markets will have an incentive to bid low for the real-time energy portion of these ancillary services bids. There will also be an additional incentive for firms to keep the market clearing capacity prices for the non-spinning and replacement reserve markets down in order to reduce the adder on the energy bids associated with their spinning and non-spinning reserve units.

5.2. Revise or Supplement the Existing RMR Contracts

As described in section 4.4, RMR contracts in their current form have done very little to reduce market power problems, and are most likely contributing to them. Recall the negative relationship between the frequency of market participation by generating facility and the level of its RMR capacity payments discussed earlier. The frequency and severity of these problems is a question we would like to study further. However, it is clear that the ISO would benefit from additional flexibility in purchasing services either under RMR contracts or some other type of contract that could, for some units, be substituted for RMRs. The ISO would also benefit from reducing the incentive to withhold capacity from the market that some RMR contracts appear to give to their owners. Owners of RMR units have protested that allowing the ISO to arbitrarily call their units under RMR terms would discriminate against lower cost units that would otherwise be earning legitimate operating profits. This is a valid and important point. However, RMR contracts should be modified to both reduce their negative impacts on the market and provide the ISO with more flexibility.

One possible modification that would reduce many of the perverse incentives for withholding capacity from the ISO's ancillary services markets in the current contracts would be to treat the RMR contract as a reliability insurance policy purchased by the ISO from a generating facility. The ISO would pay, at the beginning of the contract period,[34] a non-refundable, up-front payment to the unit's owner, that both parties deem to be a 'fair.' The ISO would then gain the right to call on this unit for local grid reliability reasons and to provide ancillary services. This fixed payment or reliability insurance premium would be independent of the number of hours in which the unit actually operates. It should be designed to pay the unit owner a sufficiently large fraction of its fixed costs, that it is willing to be called under an RMR contract.

It may appear that, under this arrangement, the ISO would pay a larger share of the unit's fixed costs if that unit were called upon less than was expected. However, under existing RMR contracts the generators themselves, through the bidding (or not bidding) of their units, can directly influence how many hours the unit is called under an RMR contract. Under the current contract terms, it is our understanding that from discussions with the ISO Market Surveillance Unit that almost no units are called *less* than expected, and many are called far more than was expected. With an up-front payment of fixed costs, the RMR units would most likely receive no more fixed cost compensation than they do now, but would not have to distort the market through the non-bidding of their units in order to do so.

Under a reliability insurance policy, the ISO would be further obligated to pay the unit's variable cost for every hour in which it operates under a RMR contract. If necessary, the conditions under which the unit would be called could be limited to some form of 'market first' criterion, as long as the market upon which that criterion is based is shown to be workably competitive. Under the scheme in which the RMR is only compensated for its variable cost of providing energy under the RMR contract, generators owning units with this type of reliability insurance policy would have extremely strong incentives to bid into the market during hours when they expect the PX or real-time price to be in excess of their variable cost of producing electricity, because they will only cover their variable operating costs if they are called under an this contract, but may earn far in excess of this amount if they called in the PX or real-time energy market.

The ISO would also benefit from contracts for the provision of ancillary services that it could invoke for economic, rather than reliability based reasons. If RMR contracts must include a 'market-first' provision, a new type of contract could be created.

[34] The payments could also be made in monthly installments over the duration of the contract.

Hopefully, the existence of a second type of contract that would help fill *general*, rather than location specific ancillary service needs, would reduce the number of RMR contracts that would be needed. The price of these contracts could be based upon market-based, rather than cost-based arrangements. Expanding the menu of ancillary services contract only be should be pursued if the ISO decides to continue with its current policy of paying for some of the unit's fixed costs through a variable capacity payment per MW called under the RMR contract. However, we believe that reform of the RMR contracts to provide owners of these units with strong incentives to bid aggressively into the ancillary services markets during periods of high system demand, will go a long way towards making the less markets workably competitive.

5.3. Grant Market-Based Rates for all Market Participants

It will be very difficult for prices in the many interconnected markets of California's electricity industry to equilibrate if regulatory price-caps are applied unevenly across firms and across markets. Therefore the elimination of cost-based caps for the remaining firms that are subject to them is a precondition for the markets to reach their intended form. There are valid arguments on both sides of the question of whether to grant market-based rates to all firms. Even after the divestiture of some of its gas-fired generation, Pacific Gas & Electric still has ownership over half of the 10-minute ramping capacity in the ISO system. PG&E is likely to be a pivotal supplier of both regulation and spinning reserve a large portion of the time. We are currently examining the number of hours in which PG&E (and other firms) are currently pivotal bidders in these markets.[15] PG&E controls large shares of the ancillary service capacity in the northern California zone.

However, it seems reasonable that the decision to let a market process determine prices for a given product should be made on a market-wide, not firm by firm basis, so long as the ISO retains the authority to impose a damage control price cap (as we recommend below). If a market is viewed to be workably competitive, all firms should be eligible for market-based rates. All firms are eligible for market based rates in the much larger market for electrical energy as well as the replacement reserve market. Additionally, PG&E is the largest *consumer* of ancillary services and is also subject to a rate freeze through the year 2000. These same factors that contribute to muting PG&E's incentive to exercise market power in those markets also apply to the remaining partially regulated markets.

[15] This calculation involves, for each firm, subtracting the total capacity bid by all *other* firms from the market requirement for each service. If the market requirement is greater than the capacity offered by all other firms, that firm is pivotal. A pivotal firm can receive any (uncapped) price it bids for that capacity. This calculation is often much more informative than market share calculations as a firm could be pivotal but still have a very small market share.

If PG&E is considered to control too dominant a share of the ancillary service capacity to permit market-based rates in these markets, an alternative is to place some of this capacity under either financial or physical vesting contracts until it is divested. With such a contract, the ISO, or other parties, would be entitled to a fixed amount certain ancillary services under preset "reasonable" prices. These contracts could be physical call options or even contracts for differences. In many ways, RMR contracts have indirectly served this purpose. However, as described above, the extremely lucrative terms of these contracts and the restrictive conditions under which they can be used combine to exacerbate, rather than mitigate, market power problems.

We favor purely financial contracts for differences (CFDs) for a fixed pre-determined yearly pattern of ancillary services quantities. We favor offering the signing of such contracts as a pre-condition for granting market-based rates to the remaining regulated firms. Contracts such as these have been successfully utilized, in one form or another, as a tool for mitigating market power in several electricity markets throughout the world.[34] These contracts can provide a level of insurance against market power abuse and other market design problems that RMRs currently have not provided.

Ancillary Services Contract for Differences (CFD)

An ancillary services contract for differences works as follows. Suppose a generator sells a 20 MW worth of CFDs at a price of $10/MW in the replacement reserve market. If the market price for replacement happens to be $20/MW then the generator owner pays to the purchaser the difference between the market price of $20/MW and the CFD price of $10/MW times the quantity of CFDs sold, 20 MW. This means that if the market price is instead $5/MW, the purchaser of the CFD pays to the generator difference between the CFD price of $10/MW and the market price of $5/MW times the number of CFDs sold 20 MW.

Under an ancillary services CFD, a generation owner would agree to a negotiated pattern of hourly prices throughout the year or a single price for all hours during year for each ancillary service. Associated with each of these contracts is a pattern of hourly CFD quantities throughout the year. To continue our example, suppose that at a market price of $20/MW the generator was only able to sell 15 MW of its capacity in this market, and suppose for simplicity the marginal cost of supplying replacement reserve is zero. Consequently, this generator's combined profits from its sales in the actual replacement reserve market and the CFD contracts that it owns is equal to the market price of $10/MW times the quantity sold in the replacement market, 15 MW, minus the market price of $20/MW less the CFD price of $10/MW times the quantity of CFDs sold, 20 MW. The generator profits in this case are $10*15 - 5*(20) = \$50$. Now suppose that by

[34] Such contracts have been utilized in the Alberta, United Kingdom, and Australia electricity markets. For an examination of their impact in the UK, see Newbery, David "Power Markets and Market Power," *The Energy Journal* 16(3).

bidding a lower price into the replacement reserve market the generator is able to sell 30 MW of capacity, but his greater supply lowers the market price to $5/MW. In this case the generator's profits from both its sales in the market and its CFD holdings is 5*30 + 5*20 = $250. In this case the generator makes money from actual sales in the replacement market and earns difference payments because the market price is less than its CFD price.

This example, exhibits a general phenomenon associated with CFDs. They provide strong incentives for firms to bid very low prices in order to both sell more than the CFD quantity in the actual physical market for the commodity. In this way CFDs provide a way to mitigate the incentive suppliers have to set high prices. This example, also illustrates why it is important to make the pattern of ancillary services quantities throughout the year follow the actual pattern of ancillary services that the net demanders of ancillary services expect to purchase from the net supplier of ancillary services.

By purchasing a sufficient quantity of CFD contracts, the net buyers of ancillary services can significantly mute the incentives of sellers to set high prices in the ancillary services markets. As shown earlier in the report, in general, firms attempt to set high prices by withholding some capacity the market. A firm that does this hopes that prices driven high enough to offset the lost quantity that the firm has sold. However, if a generating firm has sold a substantial quantity of CFDs it incentives to engage in this behavior are substantially reduced.[37]

The larger the quantity of CFDs a generator holds relative to its sales in the physical market, the greater its incentives are to bid aggressively to set a low price in the market in order collect difference payments from the sellers of the CFDs. The benefits associated with aggressive bidding from generators selling large quantities of CFDs are particularly great for the spin, non-spin and replacement reserve markets because the cost of supplying these services is presumably much less than the cost of supplying regulation or energy.

5.4. Retain a Damage Control Price Cap

Although the ultimate goal of regulators and stakeholders is to let market processes determine prices for electricity services in the California market, it is clear that there are currently flaws in the design and implementation of these markets. While these flaws are being identified and corrected, it is prudent to have a backstop on which to rely upon. The various price caps that the ISO has to date imposed have been set at levels that hopefully would not be binding if the market functions as intended. The caps are in place

[37]Because the generator is effectively short in the ancillary services market if in any hour it is unable sell the quantity of ancillary services specified in the CFD, its incentive is to set as low a price as possible in the physical market so that it receives difference payments from purchaser of the CFDs

to limit the extent to which individual firms can take advantage of market flaws. These markets continue to evolve and this report has identified several steps that could be taken to help it evolve further. While changes such as the ones proposed here are being implemented, and until participants are fully comfortable that most significant market problems have been corrected the need for damage control price caps remains. Further attention needs to be given to the question of whether the current level of the price cap is appropriate, and to developing methodologies for setting the cap.

5.5. Purchase Ancillary Services Using a State-Wide Auction

While the markets for ancillary services may at times be competitive on a state-wide basis, there is no question that the competitiveness of these markets is reduced when purchases are made by zone, rather than statewide. We are currently evaluating the relative competitiveness of both zonal markets relative to the statewide market using several measures. One way to mitigate the abuse of zone specific, locational market power is to always purchase services through a state-wide auction. This would produce a state-wide market clearing price for each ancillary service. If this price produces more services in one zone, and less services in the other, than are required, RMR contracts could be used to make up the difference in the zone with the shortfall.

The following example illustrates how this might be accomplished. Assume that a single firm owns all the ancillary service capacity in zone A, and that several firms compete to provide ancillary services in zone B. Further assume that the ISO needs to procure 2000 MW. However, with congestion, the actual location specific need for ancillary services is 1000 MW in each zone. If purchased on a zonal basis, the firm in zone A could exercise monopoly power and, given demand inflexibility, force prices to always be equal to whatever limits were imposed, say $250. Assume that the firms have the following characteristics.

EC 001207855

Firm	Zone	Unit Name	Capacity	Bid
1	A	Alpha_1	500	10
1	A	Alpha_2	500	250
1	A	Beta_1	500	250
2	B	Delta_1	500	25
2	B	Delta_2	500	30
3	B	Gamma_1	250	10
3	B	Gamma_2	250	20
4	B	Epsilon_1	500	15
4	B	Epsilon_2	500	30
5	B	Eta	250	250

Table 7: Sample Firm Characteristics

Given the above unit capacities and bids, if the ISO conducted its auction on a zonal basis firm 1 would be awarded all 1000 MW of capacity in zone A at a price equal to the market limit. Note that firm 1 is *in the market* with all its units, so that the ISO could not call upon any of these units under current RMR protocols. This is an extreme example of how RMRs do not help the problem of local market power if the market is defined to be too small. Competition is quite robust in zone B, with firms 3 and 4 each supplying 500 MW at a market clearing price of $20, set by firm 3.

Purchase Protocol	Zone A		Zone B	
	Marginal Unit	Price	Marginal Unit	Price
Zonal	Alpha_2	$250	Gamma_2	$20
Merged	Delta_1*	$25	Delta_1	$25

*This unit would set the price but not be called upon to provide reserves.

Table 8: Sample Market Outcomes

If, however, the auction were combined to draw supply from *both* zones A and B, the bid stacks of all firms would be combined. Using the above bids, 2000 MW of supply would be reached with 500 MW each being supplied by firms 1, 2, 3, and 4. The market clearing price would be set by firm 2 at $25. Firm 1's attempt to set the price at $250 would be undermined by the aggressive bidding of firms in zone B. This allocation of supply, however, would result in 1500 MW in zone B and only 500 MW in zone A, where an additional 500 MW would be needed. Under such a circumstance, only 1000 MW would actually be purchased in zone B (the same as before) at a price of $25. The remaining units in zone A are now *out of the market* due to their high bid prices. One of these units would be called to serve the shortfall under an RMR contract.

This example illustrates how it is necessary to enlarge the market in order for RMRs to begin to function in the manner in which they were intended. If a zonal market is not sufficiently competitive, then RMRs will not help to mitigate market power when reserves are acquired on a zonal basis. Note that in the example given above, firm 1 would benefit from changing the bids of its remaining units to $20, which is the market clearing price in zone B at 1000 MW of supply.[34] Thus, in this example, merging the zones helps encourage more aggressive bidding on the part of some firms.

5.6 Revise protocols to help reduce the need for regulation services

Because of the amount of input and comment we received during our telephone interviews and public meetings on the larger than expected purchases of regulation capacity by the ISO, we felt this was an issue worthy of further study and public comment. Because no committee member is an expert in power systems engineering, we can offer no concrete recommendations for changes in operator protocols. Nevertheless, would like to continue our dialogue with the ISO's operations staff in order to better understand this very complex problem.

We do have one recommendation in regard to this topic. Many countries around the world have restructured their electricity industries to some extent. The operational experiences of these electricity supply industries both before and after restructuring may enable the ISO to provide an answer to the question of whether or not their operators are procuring "too much" regulation, or if the operating a competitive electricity market simply requires significantly more regulation reserve. In addition, the experiences of these countries in reducing their ancillary services purchases over time, offers the ISO the opportunity to benefit from these experiences and more rapidly reduce its own demand for regulation.

[34] This analysis assumes that RMR prices are set at reasonable levels, if the RMR rates on all these units were very high they would most likely stay out of the market intentionally in order to collect this more lucrative payment. This problem is discussed in section 3.4.

6. Conclusions

Rather than reproduce the summary of our recommendations, the committee would like to instead re-affirm its conviction that the PX and ISO energy markets and the ancillary services markets can be made workably competitive. We believe that the adoption of the recommendations contained in this report can put the ISO on track to achieve its goal of competitive markets for electricity. On the other hand, these markets are rapidly evolving in terms of both the numbers, sizes and strategies pursued by market participants, so that the process of ensuring this transition to competition remains on track is ongoing and requires periodic detailed analysis of market data. This will allow the ISO management to anticipate many market power and other structural problems with the market before they occur. For that reason, we hope to continue research on the topics for future investigation described throughout this report.

Appendix A: Description of Software Related Problems

This attachment describes various other software related problems that have been hindering performance in the ISO's markets. These problems have been identified either by the ISO or market participants.

1. Inability of the Real-time Dispatch Software (BEEP) to Track Operator Dispatch Instructions

   The ISO real-time dispatch software (Balancing Energy and Ex-post Pricing; BEEP) runs every 10 minutes, but its dispatch instructions for the non-AGC units are not executed automatically. For many resources in the BEEP stack, instructions must be communicated by voice to the field to increase or decrease generation as instructed by BEEP. The 10-minute interval between two successive BEEP executions is sometimes inadequate to permit the ISO operators to complete this manual process for all units designated by BEEP. However, BEEP assumes its instructions are implemented, interprets the outstanding imbalance as new imbalance energy, and moves up the BEEP stack to higher priced energy bids to dispatch additional energy in the subsequent 10-minute interval. This may result in higher and more volatile real-time prices. It also reduces the available supply of real-time imbalance energy. This deficiency was the primary reason for imposing the real-time energy bid price cap as a precondition for the transfer of operational responsibility to the ISO at start-up.

   A fix is due to be implemented in the forthcoming release of the BEEP software to allow the ISO operator to indicate the units called, and to have BEEP throw back into the BEEP stack those energy segments that it selected but the ISO dispatcher did not succeed to call. In the mean time the ISO has implemented a manual process whereby the ISO dispatcher can manually adjust (bias) the amount of imbalance energy seen by BEEP, based on their estimate of the amount of MW instructed by BEEP that could not be implemented in the field. This manual workaround has partially mitigated the problem to some extent.

2. Mishandling of Downward Regulation in Sequential Ancillary Service Evaluation

   The Ancillary Services Management (ASM) software processes ancillary service capacity bids sequentially in the following order: Regulation, Spin, Non-spin, and Replacement. The capacity selected from a unit for each market is subtracted from the total capacity available from that unit for the market processed next in the sequence. However, the software does not distinguish between downward and upward regulation ranges in computing the available capacity for the next market. For example, consider a 250 MW unit with a ramp rate of 20 MW/min that has won a day-ahead energy schedule of 150 MWh for a given hour. This unit may wish to bid $\pm$50 MW in the regulation market (50 MW upward and 50 MW downward), and to have its remaining 50 MW capacity bid into the spin market. If this unit is selected in the regulation market, its total range of regulation (from -50 MW to +50 MW, i.e., a total of 100 MW) is subtracted from the available capacity, disallowing its remaining available 50 MW capacity bid to the spin market.

A fix is being implemented to correct the problem before the end of August 1998.

3. Inadequate Verification of Eligibility of Ancillary Service Bids

At present there is no verification in the Ancillary Services Management (ASM) software to ensure the capacity bid from a unit into the ancillary services market is in fact available. For example a 720 MW unit with an energy schedule of 460 MW could bid and win 240 MW of spin capacity in the day-ahead market and 240 MW of non-spin capacity in the hour ahead market, although the sum of its energy and ancillary service schedules (460 + 240 + 240 = 940 MW) exceeds its capacity (720 MW).

A fix is being implemented to correct the problem before the end of August 1998.

4. Lack of Coordination between Congestion Management and Ancillary Services Management Software

Currently the final schedules processed by the Congestion Management (CONG) software are not used in the Ancillary Services (A/S) bid evaluation. This may result in an A/S capacity schedule that is inconsistent and infeasible with the final energy schedule. This software deficiency was the basis for a temporary suspension of the penalty associated with the failure to provide ancillary services awarded in the day-ahead market, when the energy schedule is changed by CONG.

The Ancillary Services Management (ASM) software is being modified to consider unit final schedules, along with the unit physical limits and ramp rates in the release scheduled for the end of August 1998.

5. Settling Ancillary Service Responsibility based on Scheduled rather than Actual Load

At present the ancillary service capacity responsibility of each Scheduling Coordinator (to be self-provided or purchase from the ISO) is based on the SC's day-ahead (or hour-ahead) schedule rather than the actual load and generation. This has led to incentives for under-scheduling of load (and generation) in the day-ahead and hour-ahead markets, thus making it more difficult and costly for the ISO to operate the system reliably in real-time.

A change in the settlement software is contemplated to allocate ancillary service costs based on actual rather than scheduled load.

6. Improper Settlement for Replacement Reserves

The Settlement software at present allocates Replacement reserve capacity costs among the SCs in proportion to their scheduled loads. The proper settlement for Replacement reserve capacity would be based on the deviation between actual and scheduled load of each SC.

This change is contemplated as a future upgrade of the settlement software.

7. Lack of Proper Coordination Between ISO's Dispatch and Automatic Control Software

The real-time dispatch software (BEEP) is not closely coordinated with the Automatic Generation Control (AGC) software of the ISO Power Management (PMS) subsystem. BEEP uses fixed hourly schedules and load forecasts as reference. Although it perform a transition trajectory at the hour boundaries based on hourly schedules and load forecasts, it does not have any feedback from the field as to where each unit is actually operating. It assumes that all units are following their schedules and that the imbalance is mainly due to changes in system load and interchange. The generation deviations are sensed by BEEP indirectly through the impact of energy imbalance on the regulating units. This means that generation deviations are sensed only after regulating units (which are supposed to be "net-zero-energy" resources) have deviated rather largely from their base operating points (or Preferred Operating Point, POP). In other words, regulating units carry the burden of "load following" before BEEP starts calling upon other units to relieve the regulating units, allowing them to go back to their base point. A consequence of this is increased need for regulation reserve.

8. Lack of 10-Minute Real-time Price Information

Although BEEP computes 10-minute real-time imbalance energy prices, only the hourly average ex-post prices are published. Generators which are not under direct control (AGC) can (and do) deviate from their schedules or their Preferred Operating Points (POP) determined by the ISO. The generators are paid the real-time hourly average price for such uninstructed deviations. The uninstructed deviations are often intentionally maneuvered by the generator owners in reaction to real-time prices. The delayed (hourly) reaction of such generators to real-time price information may exacerbate the real-time energy imbalance fluctuations, and increase the need for regulating units which respond automatically and quickly to energy imbalance fluctuations. Publishing 10-minute prices will reduce the information time lag, provide for more timely response of generators to real-time prices, and hopefully reduce the amount of regulation capacity presently needed during shoulder hours.

Publication of 10-minute prices is scheduled in the forthcoming release of BEEP.

9. Failure to Track Uninstructed Deviations using Reserved Capacity

At present the software does not have the capability to recognize and penalize a generator that uses part of its capacity reserved for ancillary services (spin, non-spin, or replacement) to generate uninstructed energy in real-time. The ISO must resort to sporadic manual scrutiny of individual units to detect such problems.

10. Improper Payment for Uninstructed Deviations

At present BEEP uses the hourly average of the 10-minute imbalance energy prices to settle uninstructed deviations (computed as the difference between the hourly energy from the unit and its hourly schedule as modified by the BEEP 10-minute instructions). The 10-minute BEEP instructions are settled at the 10-minute Inc or dec prices as applicable (as if the instruction were followed). This process causes two problems:

Problem 1: The ISO will end up with a net loss in each hour. The following simple example demonstrates the point: For simplicity assume that there is an imbalance of +300 MW (surplus) in the first10-minute interval (i.e., an energy surplus of 50 MWh), and an imbalance of -1200 MW (deficit) during the second 10-minute interval (i.e., an energy deficit of 200 MWh) due to schedule deviations (uninstructed schedule changes). The ISO calls upon the most expensive decremental bid (say 6 $/MWh) for the first interval, and on the least expensive incremental bid (say 30 $/MWh) for the second interval. The second unit will thus be incremented by 900 MW (i.e., 150 MWh of energy) since BEEP will first restore the first unit to its original schedule before incrementing the second unit. The decremental price in the first 10-minute interval is 6 $/MWh; the incremental price in the second interval is 30 $/MWh. For the instructed deviations, the ISO charges the first unit 6*50 = $300, and pays the second unit 30*150 = $4500, a net payment of $4200. The hourly average imbalance energy price is (300+4500)/(50+150)= 24 $/MWh. Thus for the uninstructed deviations the ISO collects 200*24 - 50*24 = $3600. The ISO runs short by ($4200 - $3600), i.e., $600.

Problem 2: A gaming opportunity is provided since a unit is rewarded for not following the ISO instructions. In the above example, assume that the first unit does not obey ISO's instructions. It will have an uninstructed deviation (surplus) of 50 MWh for which it will get paid at the hourly average rate, 50*24 = $1200. Considering its payment to the ISO for its instructed decremental deviation (50*6 = $300), it will have a net gain of ($1200 - $300) = $900. In general, any unit that does not follow BEEP's instructions will end up with a positive net cash flow under the existing settlement process.

The source of both problems is using the average hourly price for uninstructed deviations. One way to correct the problem is to pay uninstructed excess generation (or under-consumption) the minimum of the 10-minute decremental prices for the hour, and charge the uninstructed under-generation (or over-consumption) based on the maximum of the 10-minute incremental prices for the hour. Regulation energy would still be settled at the average hourly ex-post price since it is under ISO's control (no maneuvering by the unit owners), and because the 10-minute reverse pricing for regulation energy could render the REPA payment inadequate as an incentive for participation into the regulation market.

11. Ignoring Impact of Ancillary services on Congestion

Presently the ASM and CONG software both ignore the potential impact of ancillary services on inter-zonal congestion within the ISO control area (e.g., Path 15). For example:

- If there is no congestion in the day-ahead, the ancillary services may be procured system-wide with no account for the fact that they may cause congestion if called upon.
- If there is congestion in the day-ahead, the ancillary services must be procured on a zonal basis according to the current protocols, even if by system-wide procurement, they could possibly relieve congestion (by creating counter flows if called upon).

12. Lack of Explicit Requirement for Downward Regulation

At present the ISO does not have the software capability to state and procure the upward and downward regulation capability it needs. The requirement for regulation can be stated only as a percentage of the load without consideration of the direction of regulation. The ISO may end up paying for excessive regulation in a direction that it does not need, and/or may have to procure more regulation (or call upon RMR units) to ensure it does get adequate regulation capacity in each direction. The ISO software is under review to permit procurement of upward and downward regulation separately.

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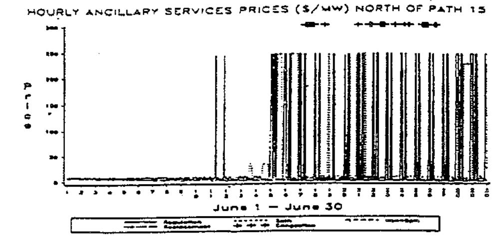
Figure 1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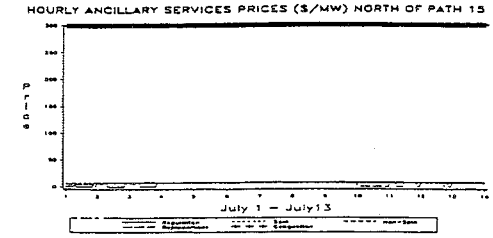
June 1 — June 30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July 1 — July 13

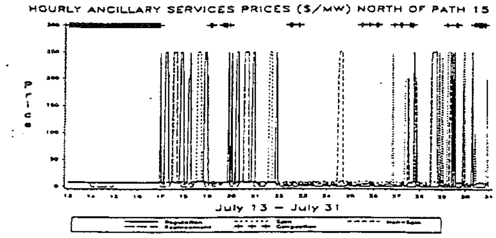
HOURLY ANCILLARY SERVICES PRICES ($/MW) NORTH OF PATH 15
July 13 — July 31

Figure 2

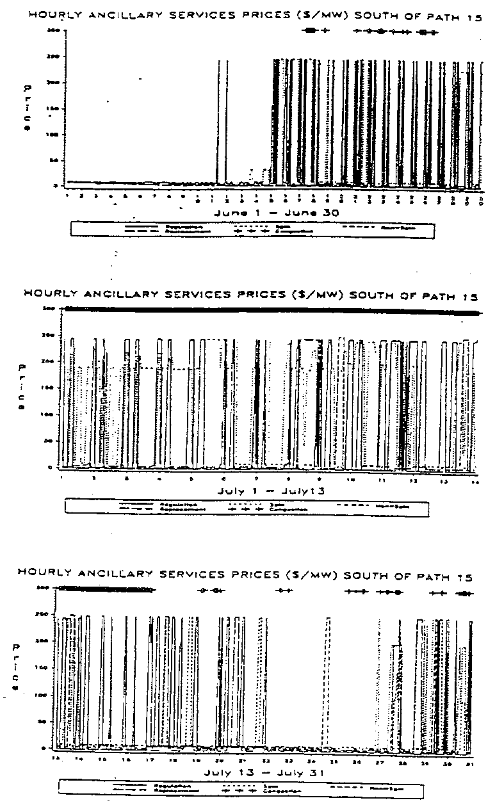

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Figure 3

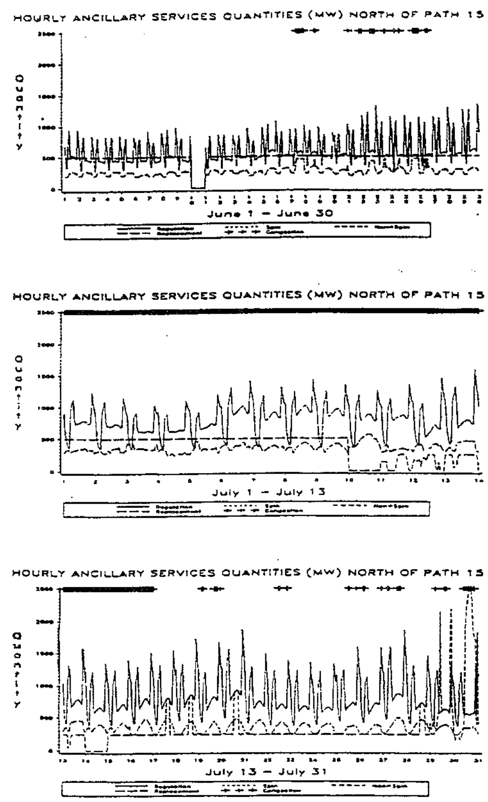

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Figure 4

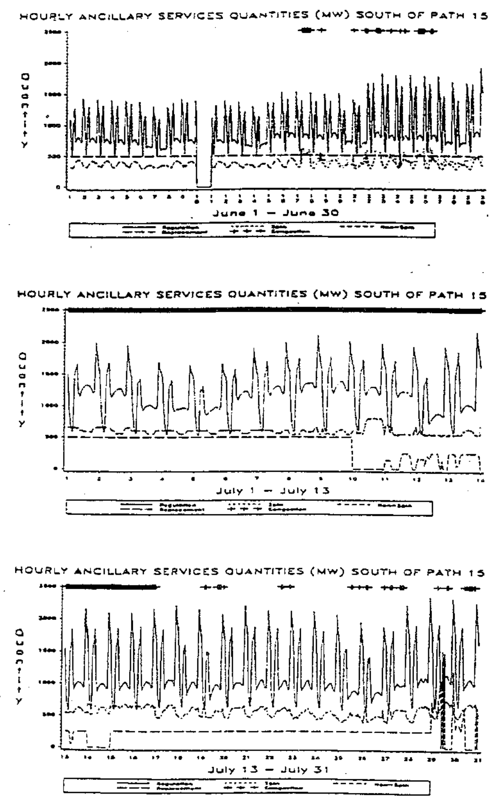

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Figure 5

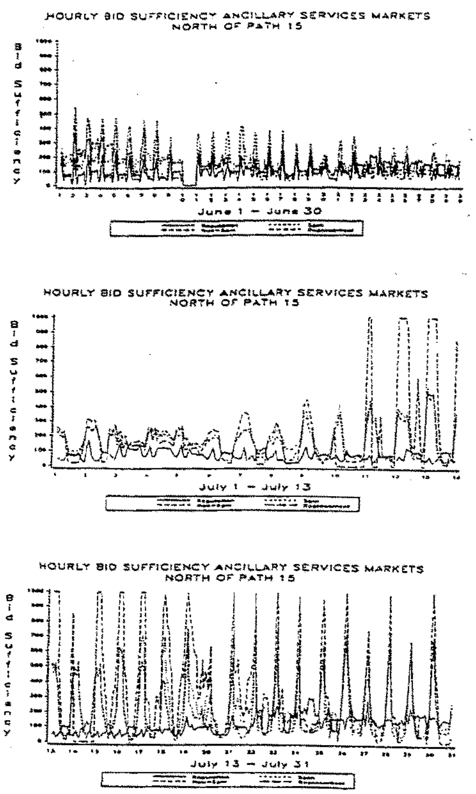
HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
NORTH OF PATH 15
Bid Sufficiency
June 1 – June 30
HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
NORTH OF PATH 15
Bid Sufficiency
July 1 – July 13
HOURLY BID SUFFICIENCY ANCILLARY SERVICES MARKETS
NORTH OF PATH 15
Bid Sufficiency
July 13 – July 31

Figure 6

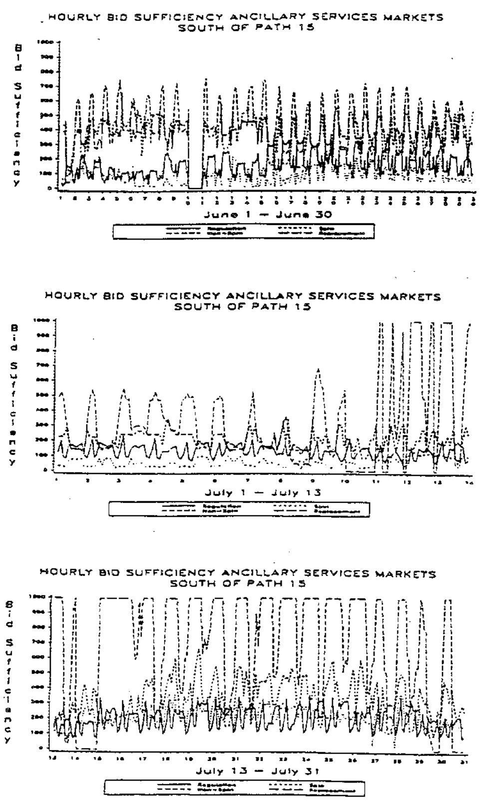

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Figure 7

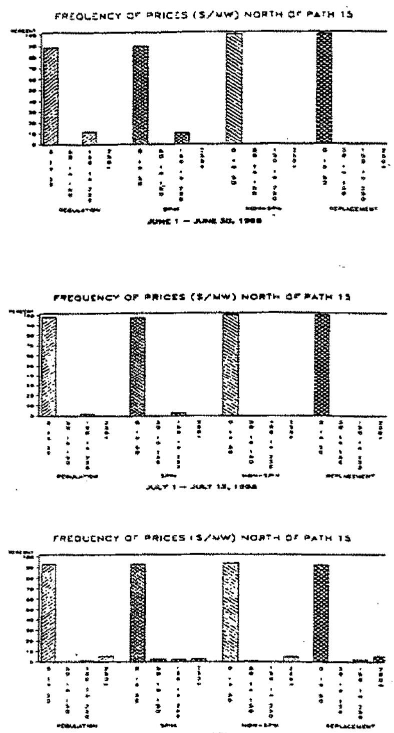

FREQUENCY OF PRICES ($/MW) NORTH OF PATH 15
JUNE 1 – JUNE 30, 1998
FREQUENCY OF PRICES ($/MW) NORTH OF PATH 15
JULY 1 – JULY 13, 1998
FREQUENCY OF PRICES ($/MW) NORTH OF PATH 15
JULY 14 – JULY 31, 1998

Figure 8

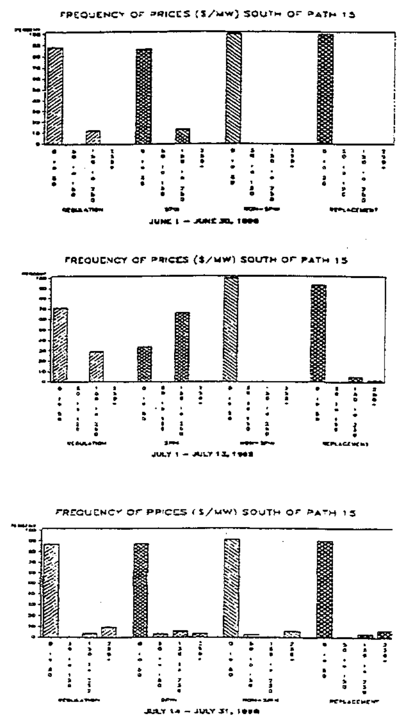

FREQUENCY OF PRICES ($/MW) SOUTH OF PATH 15
FREQUENCY OF PRICES ($/MW) SOUTH OF PATH 15
FREQUENCY OF PRICES ($/MW) SOUTH OF PATH 15

Figure 9

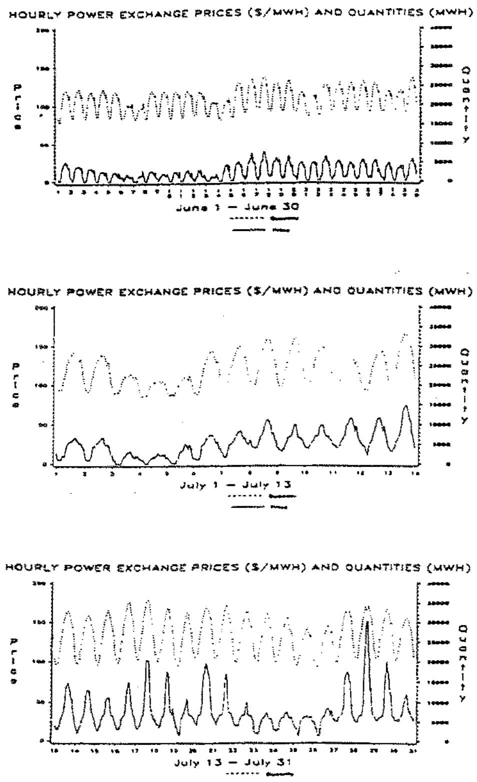
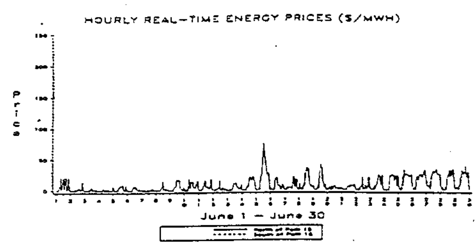
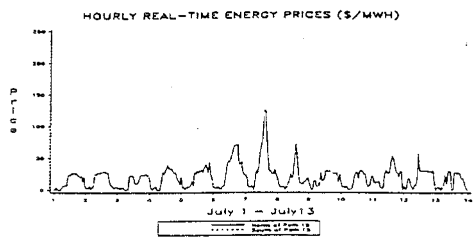
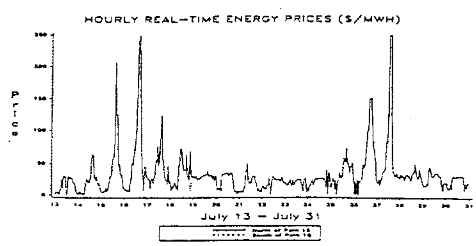

HOURLY POWER EXCHANGE PRICES ($/MWH) AND QUANTITIES (MWH)
June 1 — June 30
HOURLY POWER EXCHANGE PRICES ($/MWH) AND QUANTITIES (MWH)
July 1 — July 13
HOURLY POWER EXCHANGE PRICES ($/MWH) AND QUANTITIES (MWH)
July 13 — July 31

Figure 10







EC 001207873

Figure 11

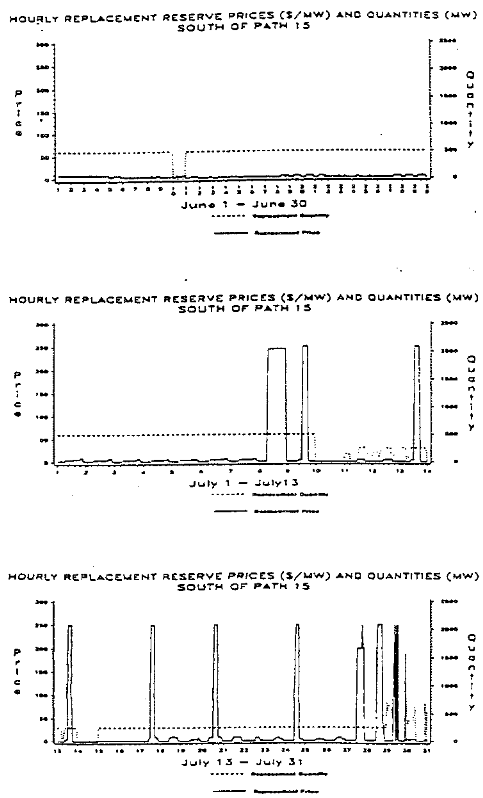


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Figure 12

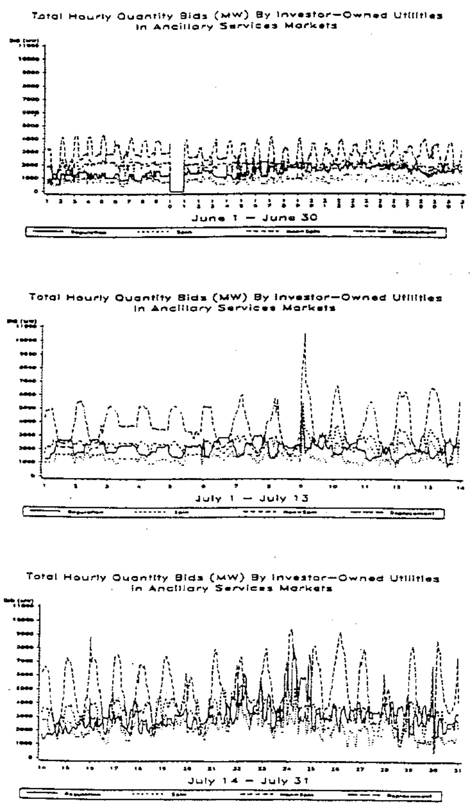

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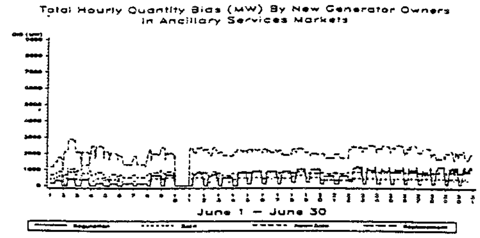
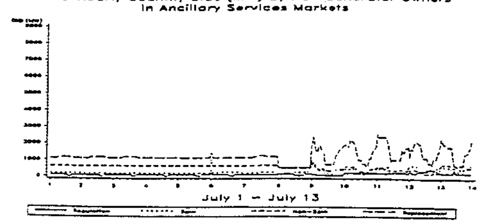
Figure 13

Total Hourly Quantity Bids (MW) By New Generator Owners In Ancillary Services Markets



Total Hourly Quantity Bids (MW) By New Generator Owners In Ancillary Services Markets



Total Hourly Quantity Bids (MW) By New Generator Owners In Ancillary Services Markets

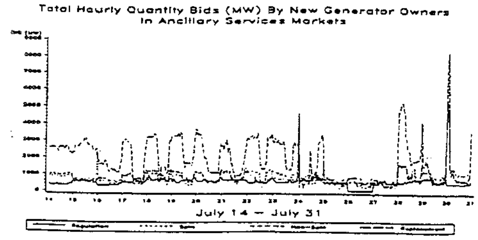
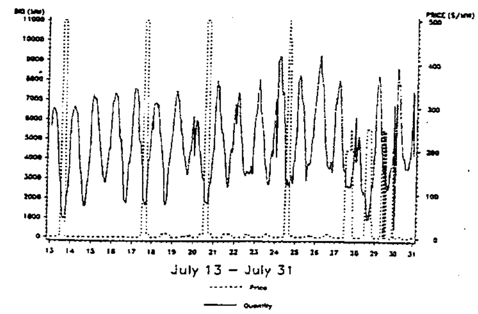


Figure 14

Total Hourly Quantity Bid (MW) By Investor-Owned Utilities
And Price ($/MW) in Replacement Reserve Market South of Path 15



Total Hourly Quantity Bid (MW) By New Generator Owners
And Price ($/MW) in Replacement Reserve Market South of Path 15

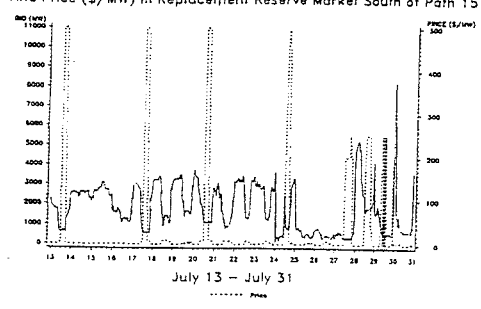


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Figure 15

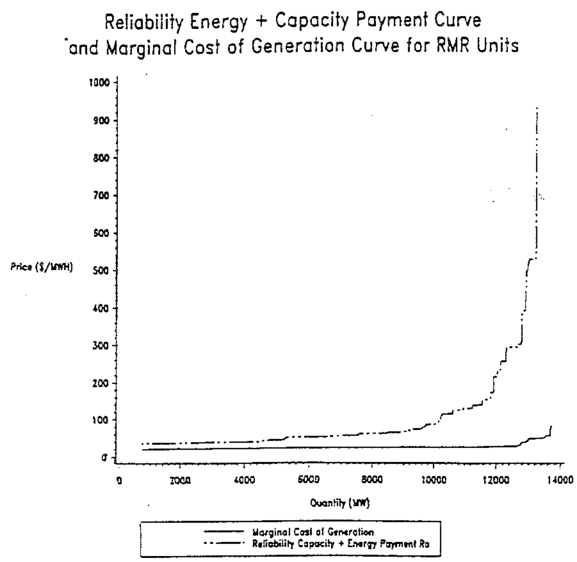

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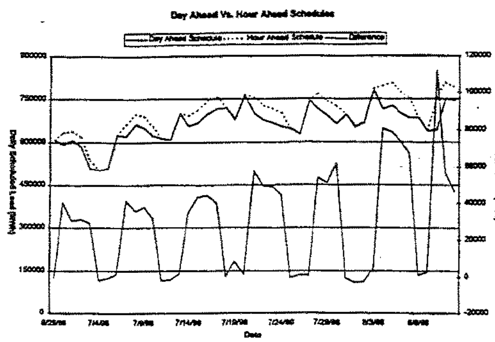
Figure 16: Schedule Imbalances Over Time



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[Form of Notice]

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

AES Redondo Beach, LLC AES Huntington Beach, LLC AES Alamitos, LLC	)))	Docket No. ER98-2843-000 Docket No. ER98-2844-000 Docket No. ER98-2883-000 (Not Consolidated)
Long Beach Generation, LLC El Segundo Power, LLC	))	Docket No. ER98-2972-000 Docket No. ER98-2971-000 (Not Consolidated)
Ocean Vista Power Generation, LLC Mountain Vista Power Generation, LLC Alta Power Generation, LLC Oeste Power Generation, LLC Ormond Beach Power Generation, LLC	)))))	Docket No. ER98-2977-000

NOTICE OF FILING

(________________)

Take notice that on August 19, 1998, the California ISO Market Surveillance Committee filed with the Federal Energy Regulatory Commission its "Preliminary Report on ISO's Ancillary Services Market" prepared in compliance with the Commission's July 17, 1998, Order in the above-identified proceedings.

Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR §§ 385.211 and 385.214 (1998)). All such motions or protests should be filed on or before ________________. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

David P. Boergers
Secretary

3034834.1

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing Preliminary Report on ISO's Ancillary Services Market upon each person designated on the official service list compiled by the Secretary in this proceeding. Dated at Washington, D.C., this 19th day of August, 1998.

Michael E. Ward

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3000 K Street, N.W.
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3036991.1

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98 AUG 17 PM 4:20
FEDERAL ENERGY
REGULATORY
COMMISSION

August 17, 1998

The Honorable David P. Boergers
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: AES Redondo Beach L.L.C., et al., Docket Nos. ER98-2843-001, ER98-2844-001, ER98-2883-001 (Not Consolidated), ER98-2971-001, ER98-2972-001 (Not Consolidated), ER98-2977-001, EL98-62-000

Dear Secretary Boergers:

The California Power Exchange Corporation ("PX") respectfully submits this filing containing a copy of the Report on Market Issues in the California Power Exchange Energy Markets prepared by the PX Market Monitoring Committee pursuant to the Commission's order of July 17, 1998 in the above captioned dockets.

The PX Market Monitoring Committee believes that this submittal should comport with the Commission's requirements.

Respectfully submitted,

Reinier Lock/

Reinier Lock
Attorney for the California
Power Exchange Corporation

San Francisco Operations: 505 Sansome Street
Fifth Floor
San Francisco, California 94111
Tele: 415-954-8484
Fax: 415-954-4864

980902.0429.1

FERC DOCKETED
AUG 17 1998

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CERTIFICATE OF SERVICE

I hereby certify I that have this day served the foregoing submittal upon each person designated on the official service list compiled by the Secretary in the above referenced Dockets, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010 (1997).

Dated at Washington, D.C., this 17th day of August, 1998.

Erica Kairis

Report on Market Issues in the California Power Exchange Energy Markets

Prepared for the
Federal Energy Regulatory Commission

by
The Market Monitoring Committee
of the California Power Exchange

Roger E. Bohn
Alvin K. Klevorick, Chair
Charles G. Stalon

August 17, 1998

I. Introduction

On July 17, 1998 the Federal Energy Regulatory Commission (FERC) issued an order accepting the proposal by the California Independent System Operator (ISO) to limit temporarily the prices the ISO will pay to bidders that had been granted authority to set market-based rates for Ancillary Services. In addition to granting that authority to the ISO, FERC directed the ISO Market Surveillance Committee and the California Power Exchange (PX) Market Monitoring Committee to conduct independent studies and to file reports with the Commission within thirty days of the date of the order.

The studies were to examine "the bidding behaviors and structural characteristics of the markets that they [the Committees] each administer and to further clarify the causes of the perceived market concerns in the pleadings." Those concerns, expressed in pleadings by the ISO and Southern California Edison (SoCal Edison), were directed at the performance of the ISO markets for Ancillary Services and especially Replacement Reserves in early July. At issue, in particular, were dramatic price spikes in the price for Replacement Reserve Capacity and insufficient bids in that market and other reserve markets. The FERC expressed special interest in "how the workings of the California market and activity in the generation market affected the prices in the Ancillary Service and Replacement Reserve markets," and its interest presumably extends to the impact of activity in the ISO markets on the PX energy markets. In addition, the FERC directed that the ISO and PX market monitoring committees should address how "phase-in plans implementing new procedures such as the hour-ahead market" will affect PX and ISO markets.

The PX Market Monitoring Committee is engaged in an ongoing analysis of the structure, behavior, and performance of the PX day-ahead energy market, and it is beginning a similar study of the PX hour-ahead market, which commenced operation only on July 30th. In this report, the Committee draws on its ongoing study and the associated work of the PX Compliance Unit staff to respond to the FERC's inquiries. To answer the Commission's specific questions about interdependence of the PX and ISO markets, the Market Monitoring Committee has examined bidding behavior and market performance in the PX energy market especially during July and early August. The Committee emphasizes that the time constraints on the preparation of the report have limited the depth and scope of quantitative analysis that could be undertaken. The members of the Committee regard this report as part of a continuing examination and analysis of the PX markets, directed at the maintenance of competitive and efficient energy markets in California, rather than as a discrete, time-limited study.

In the next section of the report we delineate the boundaries of our analysis and characterize the product we have tried to deliver. Section III provides a review of the structure and performance of the PX day-ahead energy market from its inception to the present. Relevant characteristics of the Ancillary Services markets are also discussed. (In this report, we use

"Ancillary Services" in the generic sense, including Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves.) In Section IV we present our analysis of bidding behavior in the PX market with special attention to July including the period that generated concerns about the ISO Ancillary Services markets. Section V contains our discussion of the interactions between the PX and ISO markets. We conclude, in Section VI, with implications that we draw from our analysis.

II. The Character and Boundaries of Our Analysis

First, our report focuses on the PX market for energy and, due to the very recent introduction of the hour-ahead market, primarily on the day-ahead market. We discuss and comment on the ISO markets only to the degree that there is reason to inquire about how developments in those markets may have an impact on the PX market and vice versa. In particular, it is fundamental to recognize that the capacity available for the ISO markets and for the PX markets comes from the same generating capacity. Capacity sold in one market means less capacity that can be sold in other markets, thereby driving up prices in the latter. Therefore, we would expect a close relationship among the different markets.

Second, we have written a descriptive, analytical report. We are not assessing whether particular participants behaved well or behaved badly. Rather, we attempt to analyze how they have behaved, based on historical data, and how we might expect them to behave, based on the market rules and their incentives as we understand them. Our report is normative only to the extent that our analysis will lead us to recommend one or another policy measure.

Third, it is essential to keep in mind just how new these markets are. They are still developing and evolving in important ways. We expect behavior to change as participants gain experience; as new markets open, such as the hour-ahead market; as supply and demand change due to seasonal forces and market pressures; and as unanticipated events occur. Over time we would expect the sophistication of both the demand and supply participants to increase, and their behaviors to change. This continued evolution should be recognized when considering policy changes. Problems we diagnose now may be inherent in the market or they may be transitional difficulties.

Fourth, the information we have is limited in important ways. We do not have data on some transactions outside the PX markets, especially bilateral sales (made outside the Power Exchange market) and Reliability Must Run transactions. As a consequence, we cannot accurately characterize the degree to which some of the PX market participants are using dedicated capacity as a strategic instrument.

III. Overview of Markets and Operations

This section provides an overview of California's electricity market structure and a summary of PX operations from the opening of the market on April 1, 1998 through August 11, 1998.

PX Market Descriptions

The PX operates two separate energy markets: a day-ahead energy market and an hour-ahead energy market. The PX has been operating its day-ahead energy market throughout the four months since restructuring was implemented, while the hour-ahead energy market commenced operations on July 30, 1998.

PX Day-Ahead Market

In the day-ahead market, PX Participants submit portfolio bids to buy and sell energy for each hour of the succeeding day. These portfolio bids, which must be submitted to the PX by 7:00 a.m. on the day prior to the actual dispatch day, are used by the PX to derive aggregate supply and demand curves from which the PX establishes an unconstrained market clearing price and quantity for each hour. Following the conclusion of the day-ahead auction, successful bidders provide the PX with Initial Preferred Schedules that reflect the quantities awarded in the auction process. These schedules specify the quantity and location of loads and supplies within the grid. The PX provides these schedules, which in aggregate must be balanced with respect to supply and demand in each hour, to the ISO by 10:00 a.m. on the day prior to the dispatch day. Other Scheduling Coordinators, representing bilateral transactions, submit their balanced schedules to the ISO in a similar manner.

These schedules also include Participants' Ancillary Services Bids and Schedule Adjustment Bids (for inter-zonal transmission congestion). Upon receiving the resource schedules from Scheduling Coordinators, the ISO conducts its Ancillary Services auction and performs congestion management, thereby, making any necessary adjustments to the Initial Preferred Schedules based on participants' bids. The ISO then issues Final Day-Ahead Schedules, including the schedules for Ancillary Services, by approximately 1:00 p.m. each day, and publishes final transmission Usage Charge rates if transmission congestion has occurred. The PX then calculates Zonal Market Clearing Prices based on its Participants' Schedule Adjustment Bids and the Usage Charge rates provided by the ISO.

PX Hour-Ahead Market

In the hour-ahead market, buyers and sellers are able to adjust the positions they received in the day-ahead market. This is especially useful to distribution utilities and electric service providers who may need to modify their day-ahead market positions when demand changes due to weather conditions or supply changes due to plant outages or line de-ratings. The PX hour-ahead market also provides benefits to bilateral market participants who may wish to adjust their day-ahead market positions. The PX hour-ahead market involves trading around-the-clock through 24 hourly auctions.

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PX Schedule Coordination

In addition to operating the forward energy markets (day-ahead and hour-ahead), the PX also functions as a Scheduling Coordinator with responsibility for submitting balanced resource schedules to the ISO, providing real-time dispatch instructions to its Participants, and performing billing and settlements services for both the day-ahead and hour-ahead markets.

ISO Market Descriptions

The ISO operates the real-time Imbalance Energy market, the Ancillary Services market, and the Transmission Congestion Management market.

Imbalance Energy Market (Real-Time Market)

The ISO is responsible for balancing loads and resources in real-time. The ISO uses bids received in the Imbalance Energy market to increment and decrement resources as needed to maintain a system-wide energy balance. These bids include Supplemental Energy Bids, which Participants provide to the ISO up to one hour prior to the dispatch hour, as well as the energy bids submitted by Participants in conjunction with their Ancillary Services capacity bids, as described below. The Imbalance Energy market price is calculated in 10 minute intervals on an ex-post basis. This price is used to settle deviations between scheduled and actual quantities of supply and demand. A Participant that over-delivers relative to its scheduled quantity is paid the imbalance price, while a Participant that under-delivers relative to its scheduled quantity is charged this price.

Ancillary Services Markets

The ISO conducts four day-ahead and four hour-ahead auctions for Ancillary Services. These four Ancillary Services are: Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. Each is a capacity-only market. Bidders must also include an energy bid with each capacity bid. The Energy Bids in the Regulation market are used for validation only while the Energy Bids for Spinning, Non-Spinning, and Replacement Reserves are used, along with Supplemental Energy bids, in the real-time Imbalance Energy market. In addition to these four Ancillary Service products, which are acquired through an hourly market-clearing auction process, the ISO also is responsible for acquiring Voltage Support/Reactive Supply and Black Start capability, which it procures though a longer term contracting process.

Transmission Congestion Management

The Transmission Congestion Management market operates on the basis of Schedule Adjustment Bids (SABs) provided to the ISO by Scheduling Coordinators. These SABs indicate the willingness of a Scheduling Coordinator to increment a resource if the price increases or decrement a resource if the price decreases (vice versa for demand and exports), and are an expression of the value that the Scheduling Coordinator places on obtaining inter-zonal transmission access. The ISO uses the SABs to adjust individual resource schedules to relieve congestion and calculate transmission congestion Usage Charge rates.

Table 1 shows the detailed operational timelines for the day-ahead and hour-ahead markets.

Table 1 Timeline for Day-Ahead and Hour-Ahead Markets[1]

Day-Ahead Timeline	Day-Ahead Activity
By 7:00 a.m.	Participants submit day-ahead portfolio energy supply bids and demand bids for each hour to the PX.
By 7:15 a.m.	PX conducts day-ahead energy auction and notifies successful bidders of hourly market-clearing prices and quantities.
By 9:20 a.m. (scheduled to move to 9:10 a.m., beginning August 23)	Participants submit Initial Preferred Schedules to the PX that provide details of the specific generating units and loads that fulfill the aggregate awards in the energy auction. In addition, Participants submit Schedule Adjustment Bids for inter-zonal transmission access.
By 9:30 a.m.	Participants submit to the PX bids for Ancillary Services (regulation, spinning reserves, non-spinning reserves, and replacement reserves).
By 10:00 a.m.	PX and other Scheduling Coordinators (SCs) submit their Participants' Initial Preferred Schedules to the ISO, along with their Participants' Schedule Adjustment Bids and Ancillary Services Bids.
By 11:00 a.m.	ISO completes first iteration of inter-zonal congestion management. If there is no inter-zonal congestion, ISO issues Final Day-Ahead Schedules, including the schedules for Ancillary Services selected in the ISO's Ancillary Services auction. If there is congestion, ISO provides the PX and other SCs with the estimated Day-Ahead Usage Charges, a Suggested Adjusted Day-Ahead Schedule, and a preliminary schedule for Ancillary Services.
By 12:00 noon	If there is inter-zonal congestion, PX and other SCs submit to the ISO their Revised Day-Ahead Schedules, in response to the ISO's Suggested Adjusted Day-Ahead Schedules.
By 1:00 p.m.	ISO performs second iteration of congestion management and provides the PX and other SCs with Final Day-Ahead Schedules, including the schedules for Ancillary Services, and issues final Day-Ahead Usage Charge rates.
By 1:15 p.m.	PX and other SCs send their Participants the Final Day-Ahead Schedules, including the schedules for Ancillary Services, and the Final Day-Ahead Usage Charge rates. PX calculates zonal market-clearing prices.
By 1:30 p.m. (approx.)	ISO determines if there are any deficiencies in the results of the ancillary services auctions and evaluates Reliability Must-Run requirements relative to Final Schedules.
By 5:00 p.m. (approx.)	ISO notifies market participants of any changes in Final Day-Ahead Schedules resulting from ancillary services shortfall and Reliability Must-Run generation requirements.
Hour-Ahead Timeline	**Hour-Ahead Activity**
Not later than 3 hours prior to the dispatch hour	Participants submit energy supply and demand bids to the PX (bids are resource specific and are relative to Day-Ahead Final Schedules).
Not later than 2 hours, 50 minutes prior to dispatch	PX calculates market clearing prices and quantities, and determines Preferred Schedules.
Not later than 2 hours prior to the dispatch hour	Participants submit Schedule Adjustment Bids and Ancillary Services Bids to the PX, which in turn, submits the Preferred Schedules, Schedule Adjustment Bids, and Ancillary Services Bids to the ISO.
Not later than 1 hour prior to dispatch hour	ISO performs congestion management and conducts its Ancillary Services auction. ISO provides PX and other SCs with Final Hour-Ahead Schedules, including schedules for Ancillary Services, and final Usage Charge rates. PX, in turn, transmits this information to its Participants.
Prior to dispatch hour	PX calculates and publishes Zonal Market Clearing Prices.
Real-Time Timeline	**Real-Time Activity**
Not later than 60 minutes prior to the start of hour	Participants provide Supplemental Energy Bids to the PX and other SCs.
Not later than 45 minutes prior to the start of hour	PX and other SCs submit Supplemental Energy Bids to the ISO for use in the real-time market.

[1] Target timetable; actual performance varies depending on circumstances.

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Bidding in multiple markets

Most participants will be eligible to bid in several of the markets. The exact sequence of bids and responses affects how they will do so. Prior to their 7 a.m. day-ahead bids, generators must make an approximate decision about the split between what they want to offer in the day-ahead and Ancillary Services markets. Bids in the day-ahead energy market are accepted before bids in the AS market need to be placed. If generators want to offer a larger quantity in any AS market, they must offer a smaller quantity in the day-ahead market. They can implement this directly, or they can offer the smaller quantity at "reasonable" prices, and then offer the rest at very high prices. Once the day-ahead market results are revealed at 7:15 a.m., the generators know how much capacity they can offer to the AS markets.

The method the ISO uses for sequencing the four AS markets also is important. Generators can bid simultaneously in all four markets, according to the following hierarchy:

- Regulation
- Spinning reserves
- Non-spinning reserves
- Replacement reserves.

The ISO resolves the four markets in order. Any bid in a lower numbered market that is not accepted is automatically assumed to be a bid in the higher numbered markets. In this way, the generator does not have to enter separate bids in each market, and the same MW of physical capacity can be entered simultaneously into all four markets. If some of the MW are not purchased in the spinning reserves market, for example, they are automatically offered to serve the non-spinning or replacement reserves markets. Thus, unlike the choice between day-ahead and Ancillary Services markets, participants do not need to decide in detail to which AS market they would like to offer, except insofar as their units are physically constrained to one or another market.

This ability to bid well above the predicted market clearing renders problematic the interpretation of the "quantity" a participant bids into the market. For example, the ISO's motion requesting a stay of the FERC's June 30 and July 10 orders states (p 25):

> Moreover, the Ancillary Services markets are already depressed by the bidding rules that govern the Utility Distribution Companies. They must first bid their available generation into the Power Exchange. They are not free to hold it out for the Ancillary Services auctions and can participate in those auctions only if and to the extent that their bids are not accepted by the Power Exchange.

This is technically correct but irrelevant. By bidding a price of $250/MWh or higher for some of its capacity, any participant including an IOU can be almost assured that the capacity will not be accepted in the day-ahead PX market. The capacity will therefore be available for bidding in later markets, including the Ancillary Services and real-time markets. Of course, if the IOU is limited to cost-based rates for Ancillary Services, it will probably prefer to sell in the energy markets, but the choice is its own. In our analysis, we have generally interpreted offers above $250/MWh as the participant's effectively withdrawing capacity above that price from the day-ahead market.

Market Performance

During the period April 1 through August 11, 1998, the PX has successfully run its day-ahead energy market and published hourly market clearing prices and quantities every day. The hour-ahead market opened recently and is functioning properly as well. The overall trends in the PX markets during this period are summarized below.

Market Overview

The California electricity market is enormous, representing approximately $22 billion in annual revenues and 246,000 GWh of annual energy consumption, roughly 10% of the total U.S. market. The three major investor-owned utilities (Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric) account for approximately 70% of the total California electricity market on an energy consumption basis, with the balance of the market served by municipal and governmental entities. Since the market opened, the PX share of the restructured California electricity market has been approximately 88%.

PX Participants include investor-owned utilities, Federal and municipal entities, independent power producers, and power marketers, from both within and outside California. There are approximately 45 Participants certified to trade in the PX markets, with about 35 Participants active in the markets on any given day. In addition, there are about 20 entities currently in the certification process. As a result of generation divestiture, the California IOUs' share of the PX supply market has declined from about 93% in the early months of the market to about 85% in July.[1] On the demand side, the California IOUs are the dominant players within the PX, representing about 95% of the load in the day-ahead energy market.

Demand

While population and economic activity are major underlying factors determining demand for electricity, weather is the primary determinant of seasonal and daily variations in load. Temperature patterns and deviations from the expected seasonal trends throughout the Western System are important for the California market. California and the inland Southwest have desert climates with substantial air conditioning load, whereas the Northwest and Northern Rockies have more moderate summer temperatures, but higher heating loads in the winter.

Temperatures throughout the region during April were mild and continued moderate through May and June. As a result, air conditioning loads in the California market were somewhat lower than average. Temperatures in the Northwest were also below average with more heating degree days in April, May and June than normal, thus increasing nighttime heating requirements. In late June and early July, temperatures began to increase somewhat and

[1] These percentages are for generation bid by the IOUs. Much of this generation is owned by other parties and bid in at a zero price under provisions such as those for qualifying facilities.

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finally gave way to high temperatures in mid-July through early August. Electricity demand in late July and early August was up throughout the region, in some cases to record levels. Since this heat wave had an impact on the Southwest and the Northwest as well as on California, demand increased throughout the region.

Table 2 shows monthly information on PX market clearing quantities. As expected, the difference between the maximum hourly and minimum hourly clearing quantities has significantly increased since the Spring, from about 10,000 MW to 18,000 MW, thereby increasing the need for peaking resources.

Table 2 PX Market Clearing Quantities

Month	Maximum Hourly MCQ (Megawatts)	Minimum Hourly MCQ (Megawatts)	Average Hourly MCQ (Megawatts)
April	24,847	14,657	19,914
May	23,007	14,542	19,050
June	28,499	15,683	21,398
July	35,774	16,993	25,393
August*	36,376	18,075	26,784

* As of August 11.

Supply

Generation capacity in the Western region is ample, with total generation in excess of peak demands. The Western configuration is fortuitous with winter heavy load in the Northwest and Northern Rockies counterbalancing heavy summer loads in California and the Southwest. Because of the importance of the seasonal north to south interregional flows, transmission curtailments or de-ratings on the Pacific Interties can have an impact on generation supply to the California market. Similarly, unit outages, either scheduled for maintenance or unplanned, affect supply availability and thus prices in the California market.

Supply conditions were generally robust during the April through mid-July period. Hydro generation conditions in the Northwest have been generally good, with moderate impacts from spill requirements associated with salmon restoration efforts. Northern California hydroelectric generation has been abundant as the result of higher than usual snow pack and moderate temperatures.

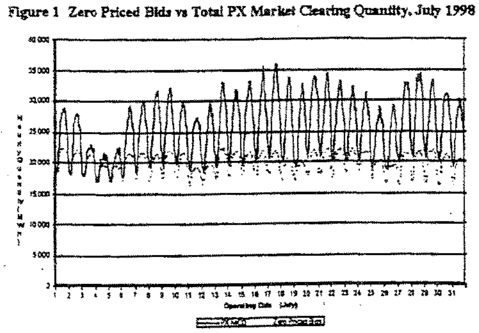
Pacific Intertie curtailments limiting the flow of power to California in July, coupled with hydro generation concerns in the Northwest in late July, contributed to upward price pressures during this period. Since late July, extreme temperatures in the Southwest and Northwest, combined with forced outages at key plants, pushed peak prices upward and led to voluntary load curtailments in several hours.

Power plant divestitures have also had an impact on the supply picture. Since the opening of the market, the California IOUs have divested approximately 12,000 MW of generation resources, mostly natural gas-fired plants. Four separate companies acquired the majority of this capacity and are now actively bidding these resources into the California market and other markets in the western states, as discussed in Section IV.

Regulatory Must-Take (RMT) generation is another important factor in the PX market. RMT resources, which include nuclear units, Qualifying Facilities, and run-of-the-river hydro, are bid into the PX at $0/MWh to ensure their selection in the auction process. Other resources, which may not be classified as RMT but which may for operational reasons want to be assured of being dispatched, may also bid into the PX at $0/MWh. These resources typically account for approximately 20,000 MW of capacity. At lower demand levels, these resources can set the market clearing price at zero, as happened in many hours in May and early June. As demand levels increased in July and August, coal units and natural gas units determined the market clearing price.

For example, in June, average hourly PX demand was 21,400 MWh, while the average hourly quantity of generation bid into the PX at zero price was 19,600 MWh, or 92% of PX market demand. In July, average hourly demand increased to 25,400 MWh, while the quantity of zero price generation bids was 19,800 MWh, or 78% of PX demand. In August, the fraction of zero price generation bids decreased to 73% of PX demand. As expected, the percentage of zero price energy bid into the PX relative to total PX demand is higher in the off-peak periods and lower in the on-peak periods. See Figure 1.

Figure 1 Zero Priced Bids vs Total PX Market Clearing Quantity, July 1998



The implication of the high volumes of zero priced bids is that the energy markets are "thinner" than they first appear. For example, suppose energy demand is 30,000 MW, zero bids are 20,000 MW, and one firm controls 3,000 MW of gas-fired capacity. It is more accurate to view this firm as having capacity equal to 30% of the price setting portion of the supply base, rather than 10% of the overall market.

Prices

The following discussion of PX market prices covers the period April 1 through August 11, 1998, and concerns PX unconstrained market clearing prices. The impact of transmission congestion on the unconstrained market clearing prices is discussed in a subsequent section.

We can roughly divide the period since the market opening into Spring (April, May, June), and July/August. Behavior of prices during the two periods was distinctly different. Table 3 summarizes the prices each month and shows the large rise from June to July.

Table 3 Unconstrained PX Market Clearing Prices ($/MWh)

Month	Minimum	Maximum	Average	Average Hours 7-22 (on peak)	Average Off-Peak hours
April	0.00	36.74	22.64	25.54	17.33
May	0.00	37.37	11.63	16.43	6.18
June	0.00	38.02	12.09	16.94	5.21
July	0.00	151.10	32.42	41.08	21.49
August*	6.79	163.01	43.13	60.93	25.50

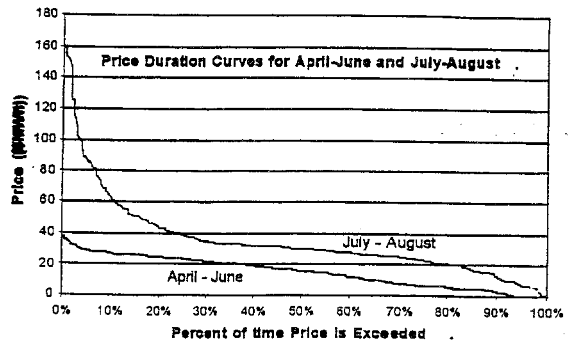
* Through August 11.

In April, the PX average hourly price was about $23/MWh, with hourly prices varying during the month from a low of $0/MWh for three hours, to a high of about $37/MWh, as shown in Table 3. In May and June, average hourly prices fell significantly from the April level, to about $12/MWh, due to moderate demand caused by mild temperatures and substantial hydro availability in Northern California. The market clearing price was $0/MWh for 43 hours in May and 87 hours in June.

Prices began to rise in mid-July as summer temperatures developed and demand levels rose. The PX hourly average price rose to $32/MWh in July and $43/MWh in August, with natural gas units setting the market-clearing price in most hours. Peak prices rose significantly as much of the West went through a severe heat wave with several control areas in California reporting all-time record loads. The maximum hourly price rose to $151/MWh in July and $163/MWh in August. In addition, zero prices virtually disappeared, with only nine hours of zero prices in July and no hours of zero prices in August so far.

Figure 2 is a price duration curve that shows the percentage of time that prices exceeded a particular level. The lower curve is for the period April 1 through June 30 while the upper one is for the higher demand period of July 1 through August 11, and illustrates the dramatic change between the periods. As shown in Figure 2, the maximum price through June did not exceed $40/MWh and price was zero about 6 percent of the time. In July-August, however, prices were above $40/MWh about 25% of the time, and price was zero only briefly.

Figure 2 Comparison of Price-Duration Curves



Price volatility

Figure 3 shows the relationship between the PX market clearing price and quantity for the period April 1 through June 30, 1998. As shown, the maximum hourly quantity was less than 30,000 MWh throughout the three month period and the maximum price less than $40/MWh, and there were significant variations in price for a given quantity. Figure 4 presents equivalent information for the period July 1 through August 11, 1998. It shows that the shape of the price-quantity relationship changed significantly as market clearing quantities (MCQ) exceed 30,000 MWh, as average prices rise steeply with market quantity above 30,000.

Figure 3 Market Clearing Price and Quantity for the Period April 1 – June 30

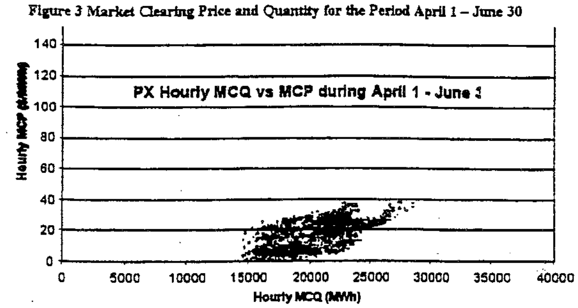
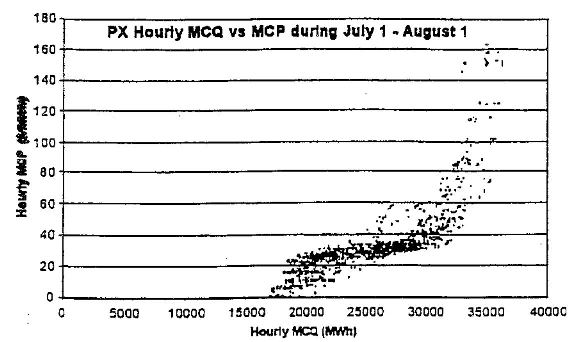


Figure 4 Market Clearing Price and Quantity for the Period July 1 – August 11



Congestion

Congestion on the major transmission paths has increased as electricity demand levels have increased. Table 4 shows the number of hours of congestion on the major transmission paths, while Table 5 shows the resulting impact of such congestion on the PX unconstrained market clearing prices.

Table 4 Congestion charges

Month	Transmission Path	Number of Hours Congested	ISO Transmission Usage Charges ($/MWh)		
			Minimum	Average	Maximum
April	So. Calif – No. Calif	0	0.00	0.00	0.00
	Calif – Oregon	1	4.14	4.14	4.14
	Calif – NOB	3	250.00	250.00	250.00
	Calif – Arizona	0	0.00	0.00	0.00
May	So. Calif – No. Calif	0	0.00	0.00	0.00
	Calif – Oregon	131	0.10	9.34	50.00
	Calif – NOB	127	0.01	40.80	250.00
	Calif – Arizona	0	0.00	0.00	0.00
June	So. Calif – No. Calif	59	0.14	3.65	25.90
	Calif – Oregon	119	0.02	4.71	14.30
	Calif – NOB	82	0.01	2.91	12.51
	Calif – Arizona	0	0.00	0.00	0.00
July	So. Calif – No. Calif	62	0.02	12.45	76.25
	Calif – Oregon	199	1.01	17.78	58.01
	Calif – NOB	95	0.01	11.51	11.51
	Calif – Arizona	0	0.00	0.00	0.00
August*	So. Calif – No. Calif	35	0.70	9.55	23.60
	Calif – Oregon	23	0.63	2.29	3.94
	Calif – NOB	7	1.87	27.91	80.86
	Calif – Arizona	0	0.00	0.00	0.00

* As of August 7.

In April and May, there was no congestion on the main transmission link between northern and southern California (Path 15, linking zones NP15 and SP15). In June and July, congestion on this path occurred in a total of 121 hours, or 8% of the time. On the California-Oregon Intertie (Northwest 1), one of two major transmission links between California and the Northwest, congestion occurred in only one hour during April. In May through July, however, congestion on this path occurred an average of 150 hours per month. On the California-NOB link, the other major transmission link to the Northwest, congestion occurred in only three hours in April, and an average of 100 hours per month during May through July. There was no congestion between California and Arizona.

The vast majority of electricity demand in California occurs in Zones NP15 and SP 15, Northern and Southern California respectively. As a result of congestion, the average PX unconstrained market clearing price in NP 15 increased an average of $1/MWh during the congested hours in the period May through July. During this same period, the average unconstrained price in SP 15 increased approximately $2/MWh during the congested hours.

Table 5 Average Price Impact on NP15 and SP15 Due to Congestion

Month	Price Impact Hours	Unconstrained Market Price ($/MWh)	Average Price Impact in SP15 ($/MWh)	Average Price Impact in NP15 ($/MWh)
April	0	n/a	n/a	n/a
May	162	16.85	1.86	1.86
June	150	21.84	1.20	0.80
July	199	42.28	2.75	0.43
August*	68	48.49	-1.41	2.18

* As of August 7.

Comparison with bilateral markets

The PX regularly compares its day-ahead energy market prices with those occurring in bilateral markets, as shown in Table 6[3]. Such comparisons must be viewed carefully since the PX prices are derived from individual hourly auctions, whereas bilateral market prices represent a relatively small volume of energy traded in aggregate on-peak and off-peak blocks, and are determined based on a survey of market participants. Nonetheless, the comparisons are tracked closely by the PX. The two primary hubs for bilateral trades in the California market are at the California/Oregon border (COB) and at the California/Arizona border (Palo Verde).

[3] Source of bilateral market prices: Energy Market Report.

Table 6 Comparison of PX Unconstrained Prices with Bilateral Market Prices ($/MWh)

	On-Peak			Off-Peak		
Month	PX	COB/ NOB	Palo Verde	PX	COB/ NOB	Palo Verde
April	25.54	25.14	25.22	17.33	16.33	14.96
May	16.43	14.82	19.62	6.18	7.60	7.97
June	16.94	15.65	20.68	5.21	5.97	7.28
July	41.08	31.39	43.81	21.49	17.02	17.48
August*	60.93	55.31	55.44	25.50	27.91	24.80

* As of August 11.

Comparison with real-time prices

As shown in Table 7, PX average hourly prices have been slightly above ISO real-time prices, although real-time prices have been more volatile, as would be expected. During the period April 1 through August 11, the PX average hourly price has been $21.67/MWh with a standard deviation of $18.80/MWh, while the average ISO real-time price has been $18.29/MWh with a standard deviation of $23.62/MWh.

Table 7 Comparison of PX Unconstrained Market and ISO Real-Time Prices ($/MWh)

Month	PX Average Hourly Day-Ahead	ISO Average Hourly Real-Time Price	PX Price Standard Deviation	ISO Price Standard Deviation
April	22.64	20.49	6.56	11.26
May	11.63	9.33	7.68	10.40
June	12.09	8.36	9.36	10.91
July	32.42	27.83	20.71	29.69
August*	43.13	42.61	34.97	48.75

As of August 11.

PX Hour-Ahead Market

The PX hour-ahead market has been in operation only a couple of weeks and has had low volumes during this initial period. Prices have exhibited significant volatility, as expected and as does the real-time market. The transaction volume in the hour-ahead market will likely increase as market participants gain additional experience with its operation.

IV. Behavior of the key participants in the markets

In this section we describe and analyze the behavior of the most relevant generating companies. These companies own or at least control gas-fired generating units. Their units play a crucial role since they provide about 17,000 MW of gas-fired capacity, which comes into play as demand rises above the level that can be met by baseload units. During the afternoon hours in July the zero-bid capacity, mainly from utilities, was greater than 20,000 MW while total demand was between 29,000 and 35,000MW. (See the discussion of regulatory must-take in Section III.) Therefore units of the "key participants" should generally be at or near the margin and always play a role in determining the market-clearing price during these hours. Our analysis, below, of the frequency with which particular participants comprise the marginal supply supports this characterization.

By examining the behavior of these generators we hope to understand better the behavior of prices in individual markets as well as the issue of spillovers from one market to the next.

We have limited our detailed analysis to ten weekdays in July: July 6-10 and July 27-31. During the first of these weeks, Ancillary Services prices were not capped, and Replacement Reserve prices reached $5000 per MW for 3 hours. During the July 27-31 period, Ancillary Services prices were capped at $250 per MW. Three of the four Ancillary Services markets hit this cap during some hours of the week. We examined the hours from 12 to 20 (11 a.m. to 8 p.m.) each day. These are the hours with the highest demands and highest prices in both Ancillary Services and energy markets.

Summary of the key participants

Nameplate capacity of the main gas-fired plant operators is displayed in Table 8. The first four owners are new participants in the California market, who purchased plants from the IOUs. The last two owners are Investor-Owned Utilities (IOUs). This table does not include 280 MW of combustion turbines owned by SDG&E, 280 MW of gas units owned by Thermo Ecotek, and various non-gas units. The table also does not include out-of-state participants, who may at times provide significant energy. Hydro units can also play a role in determining prices, particularly the 1200MW of pumped hydro owned by PG&E.

Table 8 Ownership and size of intermediate gas units

Owner	Abbreviation	Capacity (MW)	Share
AES (Williams)	WESC	3956	23%
Houston Industries	NES	3776	22%
NRG Energy/Destec	ECI	1550	9%
Duke Energy	DETM	2645	16%
Sum of these four	Independents	12,200	70%
PG&E	PGPG	3488	20%
San Diego Gas & Elec.	SDGE	1644	10%
Total		17,100	100%

Source: PX data.

Hypotheses concerning behavior of key participants

If a generator were acting like a perfect price taker, we would expect it to bid each hour with a supply curve approximately equal to the marginal generating cost up to the capacity of its units. For example, with delivered gas prices now about $3 per MMBtu, a generator with a heat rate of 10,000 Btu/kwh would bid slightly above $30 per MWh. Prices would rise above the $30 level whenever total demand, including Ancillary Services demand, exceeded the capacity of baseload (zero bid price) plus gas units. At these times, gas turbines and other special technologies would comprise the marginal supply and, together with demand, jointly determine the price. A unit with a marginal running cost of $30/MWh would then receive contributions to fixed costs whenever prices are above $30 for any reason.

We consider this the "competitive behavior model." Another important attribute of this model is that the quantity offered by each generator should add up to its capacity. But during the two July weeks we examined, the bidding of the key participants did not always fit this competitive behavior model. The firms behaved rather differently from each other, but only a few followed the predictions of the competitive model just sketched.

The behavior of the six key participants in the PX day-ahead market in July departed in two main ways from the competitive model. First, they almost never bid to supply their entire generating capacity in the PX market. Second, they often bid capacity at prices well above $30/MWh. In fact some firms bid some of their capacity at prices above $100/MWh during some hours.

For any given generating company and hour, there are at least five possible explanations why its bid quantity in the PX day-ahead market might total less than its capacity. They are:

- The participant expects one or more units to be unavailable.
- It has a bilateral contract to sell energy.
- It planned to sell capacity in one of the ISO markets. (Recall that the bids for the PX day-ahead market must be placed before bids in the Ancillary Services and other markets.)
- The participant is trying to push prices up.
- The participant hopes that by not bidding a unit, it will be called as a Reliability Must Run unit, and it will receive a higher price than it would have received in a competitive market.

With these explanations in mind, plus the default hypothesis of competitive behavior, we examined the behavior of each key participant during the hours from 12 to 20 in the weeks of July 6-10 and 27-31. Unfortunately we had very little information about the first two explanations: unit availability and bilateral contracts. This limits the inferences we can draw.

Observed behavior of participants

Different participants followed different patterns of bidding during the ten days and 90 hours we examined in detail. Several appeared to be pure price-takers. They bid a flat supply curve at a price approximately equal to the marginal cost of a gas-fired unit. Others used very elaborate bid curves that varied by hour and day. Not surprisingly, the latter were often the marginal price setters.

Some of the more elaborate bidding mechanisms used at different times by different participants included the following:

- Finely differentiated upward sloping supply curve.
- Hour to hour changes in the supply curve, shifting the curve to the left (less energy offered at a given price) at times when prices were likely to be higher.
- Day to day changes in the supply curve.
- Extensive bidding in Ancillary Services markets.
- Apparent adjusting of Ancillary Services and supplemental energy (real time) offers in response to sales in the day-ahead market.

We emphasize that without a full econometric model to explain bidding behavior – one that accounts appropriately for exogenous factors and individual units – and more data, we cannot draw firm conclusions from this examination. In particular, we cannot easily tell whether a given participant is "withholding" some of its capacity to force prices up or to induce the ISO to call a unit for Reliability Must Run status. Recall, specifically, the gaps in our data on bilateral contracts. Thus although we often observed PX-market offers and sales significantly below nameplate capacity, at this point no definite inferences can be drawn.

Our limited examination of bidding behavior, however, does provide considerable suggestive evidence that the energy markets are at times thin and not fully competitive. Therefore, any actions taken by the ISO to improve the Ancillary Services markets should be carefully scrutinized to be sure they do not adversely affect the energy markets. This is especially important since the volumes of the energy markets are about ten times larger than the volumes in the Ancillary Services markets.

It is also possible to over-offer capacity. That is, a participant can make AS bids by 9AM such that AS bids plus day-ahead sales exceed its capacity. For example, one afternoon a participant sold 80 percent of its capacity in the day-ahead market, and then bid 50 percent of its capacity in the AS markets. Because of its supply curve (bid prices) about half its Ancillary Services bids were purchased. This led to total commitments of 106% of its capacity. There is nothing necessarily wrong with this if the participant is willing to "buy back" its day-ahead energy sales in the hourly, real-time, or bilateral markets.

Who determined prices?

Since we have data on individual supply curves (bids), we can engage in some sensitivity analysis to determine which participants had the most effect on prices. In essence we ask the question, "At the actual price-quantity intersections in the marketplace, which firms were the ones with the most power to alter price by altering their bids?" We estimated this by looking at the incremental supply curve of the marginal firms, recognizing that several firms might be

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on the margin to different degrees in the same hour. This gave us a measure "percent of incremental energy from participant x." In a perfectly competitive market with six identical participants, we would expect that each participant would provide approximately 17% of the incremental energy. We interpret a disproportionate share of one firm as meaning that it had a larger opportunity to influence prices. Whether such firms used that opportunity is a separate matter.

We examined the incremental firms over the period July 1 to August 10. Only "high priced hours," i.e. those over $75/MWh, were included in the calculation. There were 70 such hours. Of the approximately 30 sellers in the market, only four were important on the margin during these 70 hours. Not surprisingly in light of the differences in bidding behavior discussed above, we found substantial differences in who was on the margin at different prices. At prices from $75 to $100/MWh, incremental supply was divided rather evenly among four firms, with two of the six key participants almost never on the margin. At prices between $100 and $125, one firm was dominant with about three quarters of the incremental energy. When the price was above $125, a different firm was dominant with about three quarters of the incremental energy.[4]

We conclude from these share numbers that at certain levels in the aggregate supply curve, a very small number of firms had the effective ability to determine the prices. In essence they dominate a horizontal slice of the aggregate supply curve, and other firms have vertical supply curves in those price regions, or bid all their capacity at lower prices. At other levels, many firms are bidding with sloped supply curves, and no one firm dominates. The Market Monitoring Committee is concerned about market concentration issues, and will monitor it closely in the future.

V. Interactions between PX and ISO markets

The prices in three ISO Ancillary Services markets and in the PX Day-ahead market are shown in Figure 5, for hours 12 to 20 on the ten weekdays we studied. All prices are shown on the same scale, which illustrates the wide variations among markets and over time. Corresponding quantities are shown in Figure 6. We show Ancillary Services prices and quantities only for the SP15 region, which is the largest demand region and was moderately more subject to high prices than NP15. As the graphs show, different markets had high prices on different days. For example, in the energy market, during these ten days prices exceeded $100/MWh only on Tuesday July 28. That day, non-spinning reserve and replacement reserve hit their caps of $250/MW, while the price for spinning reserve was about $10.

[4]: We took 90% of the original MCPs and calculated the generation from each participant at this price and at the actual MCP. The difference we considered that firm's incremental generation. This number divided by total incremental generation was the share for that participant in that hour. We then took the weighted average share for a participant across all hours in the price range, using the hours' total increments as the weights. There were 42 hours with prices between $75 and $100, 14 hours between $100 and $125, and 14 hours over $125.

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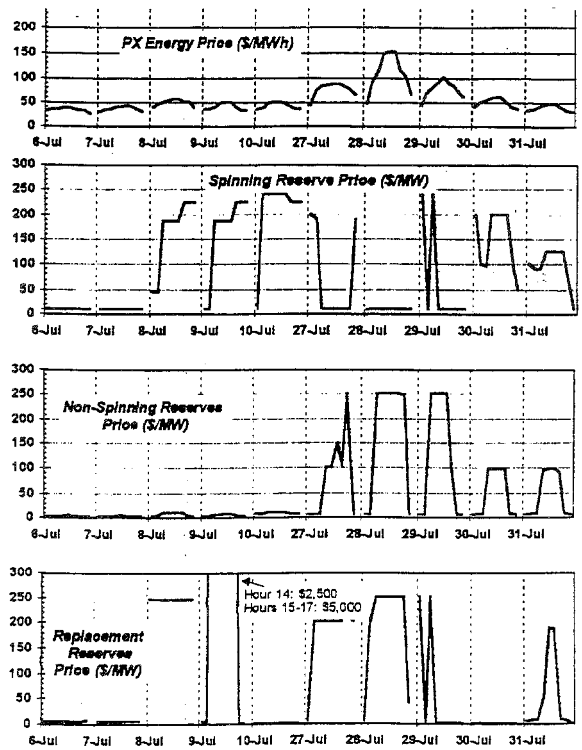

Figure 5 Energy and reserve Prices, selected days, hours 12-20

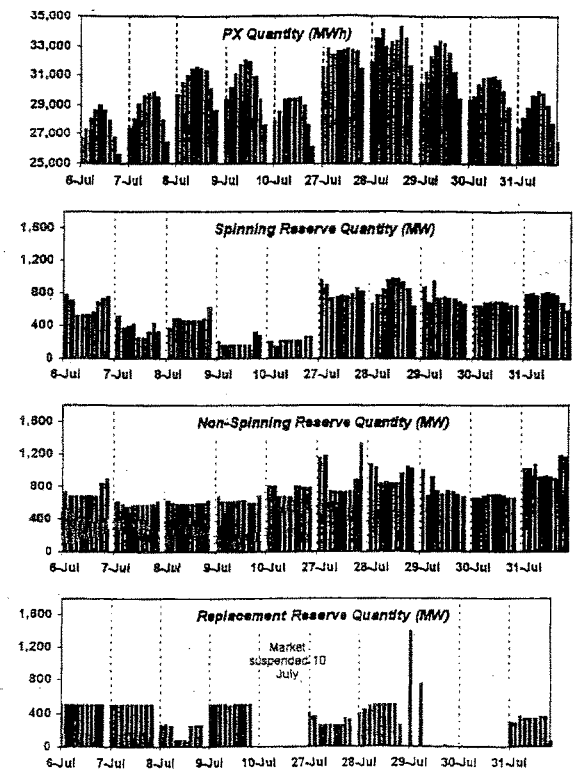

Figure 6 Energy and reserve Quantities, selected days, hours 12-20

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One hypothesis about prices in these markets is that jumps in the Ancillary Services market prices are due to increases in capacity being used to serve the PX markets, leaving little capacity for Ancillary Services..[5] During the second week we examined, the $250/MW caps were binding in many hours. We do not have access to the firms' supply curves in the Ancillary Services markets, but our examination of the data on the PX energy markets does not suggest that the $250/MW caps were hit because of any widespread withdrawal of capacity from the Ancillary Services markets in an effort to provide more to the PX market.

Our examination of individual participants' sales in the PX and ISO markets reveals that some of them adjust their 9:30 a.m. bids in the Ancillary Services markets based on what they sold in the 7:15 a.m. day-ahead market. This is an attempt to make sure that capacity not selected in the day-ahead auction does not sit idle. To the extent this occurs, it helps equilibrate prices in the different markets. In principle such behavior does create a tradeoff between the two markets; more sold in one makes less available to the other. However the effect, if it exists, is weak.

We intend to study this issue further as more data become available. Prices in Ancillary Services and in energy markets have risen recently, and there is no reason to believe that the late-July Ancillary Services prices are stable or representative of their long-term behavior.

Comparing Prices: Reserves as Options

Another way to compare the various markets is to examine the profit-making opportunities in each one. If participants are rational, can sell capacity in any market, and have low transactions costs, we would expect prices to equilibrate across markets. More precisely, in equilibrium the expected profits from allocating the last MW of capacity to all markets should be equal. Participants should move capacity from one market to another until this condition holds; until then there would be opportunities to profit from arbitrage across the markets. Casual observation of Figure 5 suggests that prices are far from this equilibrium. Although energy prices seem to follow a regular pattern, Ancillary Services prices change by an order of magnitude from each other, from day to day, and even from hour to hour.

Spinning, non-spinning and replacement reserves are all theoretically call options that the ISO is purchasing. They give the ISO the right to buy energy on a few minutes notice, if it is needed to respond to a contingency. The payments made by the ISO for reserves are per MW of capacity, and are the cost of buying the options. When these reserves are called upon by the ISO, there is also an energy payment per MWh, at the real-time price.[6]

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[5] Recall that Ancillary Services bids are made after day-ahead energy bids have been resolved. Therefore, the energy sales matter more than the energy market bids.

[6] Suppliers are required to include an energy bid with each capacity bid they submit in the reserves markets, but the energy payments they receive if they are called to provide energy are based on the ISO's real-time imbalance price. They are only called if the real-time price is at or higher than their energy bid. This means that the actual "strike" price is equal to or higher than the energy price submitted by the provider.

When, for example, the price of reserves is at $250/MW, this option character of reserves has two consequences. First, the underlying commodity (energy) has consistently been cheaper than the call option, thereby in principle creating an arbitrage opportunity. Second, when deciding how much to offer in each market, participants will make more profit by selling reserves at $250 per MW than by selling energy, even if the energy price reached $250 per MWh. The value of selling a MW as reserves is the expected reserve price plus the expected value of real time price minus marginal running cost. For example, if the reserves price is $200/MW and there is a 40% chance of being called to deliver at a $100/MWh expected Real Time price, the expected revenue is the same as selling in the energy market at $240/MWh. The reserve contract gives about the same profit as an energy price of $258 (if the marginal generating cost is $30/MWh).

The maximum price in the PX day-ahead energy market has been about $160/MWh while Ancillary Services prices have often reached the ISO cap of $250/MW. The price of reserves has exceeded the energy price in many peak hours. Table 9 shows the percentage of hours that the price for each reserve service was higher than the PX day-ahead energy price in early August. Most of the weekday afternoons had such relative prices. The reserve prices averaged close to $250/MW, because they were usually hitting the ISO's price cap. During such hours, in principle the ISO could have purchased energy and "thrown it away" more cheaply than buying the Ancillary Service.

Table 9 also shows the average day-ahead reserves price (option cost) and the real-time ISO energy price (exercise price for the option) during these high-priced hours. To calculate the total payment made to a Supplier who is called upon for reserves, one has to add the cost of the option (capacity payment) to the cost of energy when it is called during the affected hours. For example the first column shows the relevant prices for spinning reserves.

Table 9 Comparison of Revenues from 1 MW in PX and Reserve Markets

August 1 - 12, 1998	Spinning Reserve	Non-spinning Reserve	Replace-ment Reserve
Percentage of Hours that Reserve Price Exceeded PX Price	28%	20%	23%
Average PX Price During Such Hours ($/MWh)	63	90	91
Average Reserve Price During Such Hours ($/MW)	238	249	238
Average Real-Time Price During Such Hours ($/MWh)	72	108	111
Payment Above PX if Called for Capacity Reserve Only ($/MW)	175	159	147
Payment Above PX When Also Called for Energy for full Hour ($/MWh)	247	266	258

As shown in Table 9, the average payment to spinning reserve suppliers in these hours was $310/MWh ($238 + $72). The PX average energy price during the same hours was only $63/MWh. Thus, suppliers of spinning reserve energy received an average payment that was $247/MWh above the average PX price ($310 - $63). Even suppliers who were not called upon to provide energy received payments that were $175/MW above the average PX price. In a smoothly functioning group of markets, suppliers should have recognized that they could make significantly greater profits providing spinning reserves compared to bidding in the PX market during these on-peak hours.

Arbitrage should have eliminated the differential profit opportunities. It is apparent that the markets for Ancillary Services are not in equilibrium with the energy market. Perhaps because there are too few players in the Ancillary Services markets, the paradoxical price inversion persists.

If the cost of buying reserve services is higher than the cost of energy itself the same hour, the ISO would be better off buying energy in the PX day-ahead market to meet its reserve requirements. The ISO could even sell such energy to outside control areas at zero prices on the condition that it could be called back to meet ISO's reliability requirements – in essence exploiting the arbitrage opportunity between the option and the commodity. This might cause PX prices to increase, but as reserve prices dropped to equilibrium with the PX market, capacity would shift toward the PX market, thereby compensating for the ISO's purchases in the market. An entrepreneurial firm could also take advantage of this arbitrage strategy and keep the profits itself.

VI. Concluding Observations

Based on the information gathered and the study undertaken to date, the Committee has a number of concluding observations to offer. Before we present them, however, it is important to emphasize the Committee's strong belief that competitive and efficient markets can set prices and determine quantities for electricity in California. Although market experience to date indicates the desirability of adjusting some of the current structures and procedures, this does not weaken our belief that properly designed and functioning markets can do the job. The main goal should be to make long-term changes that will remedy the current deficiencies. But we recognize that the market effects of some defects may be so severe that temporary interventions are required. It is important, however, to take all steps possible to ensure that short-term actions do not impede long-term effectiveness of the markets.

We turn now to more specific observations about the PX energy markets and their relation to the ISO's ancillary-services markets. These remarks are based on our time-limited study concentrating on the performance of the PX market, the behaviors of key participants in that market, and the interactions between the PX market and the ISO's markets for ancillary services.

First, the PX Day-Ahead market has functioned smoothly since its inception in April. The Hour-Ahead market is too new to analyze, though we are concerned about how slowly activity is developing there. The Day-Ahead market is large with a number of participants. It has, however, seen some very high prices during July and August. Our review of the data gives us some cause for concern about the ability of a small number of participants to affect prices at times of high demand. This is an area that we have been watching and will continue to follow carefully, particularly since high prices on the PX market have a larger impact on the overall cost of electricity in California than do comparable Ancillary Services prices.

Second, while high prices have been of concern in the PX Day-Ahead market, they have been of even more concern in some of the ISO's Ancillary Services markets. Indeed, the level of those prices gave rise to the ISO's request to the FERC, which in turn led the FERC to call for this report. The very high Ancillary Services prices reflect an insufficiency of supply offers relative to demand at particular times, which can then bestow significant market power on the generators that provide ancillary services. The principal solution to this problem is the entry of new units and new participants into the ancillary services markets. That is, insofar as the supply-side problem is structural in character, it requires a structural solution.

Steps must be taken to encourage entry in the short and long run. Removing restrictions on who is allowed to participate in the various markets, as the ISO has recently done with out-of-control-area generators, is one way to enhance entry in the near term. To the extent that some loads can be reduced as fast as generators can ramp, encouraging demand-side bidding for ancillary services is another means to increase supply, perhaps even in the short term. Furthermore, Regulatory Must-Run contracts should be considered in the overall context of the provision of system reserves. The incentives in those contracts should be structured so that owners of such units are not inefficiently induced to withdraw from the energy market or the ancillary services markets.

While supply-side development is essential to the long-term success of the Ancillary Services markets, it is also important that the ISO's demand for Ancillary Services be rational and responsive to economic incentives, while staying within the bounds of regulatory constraints and reliability objectives. The overall level and composition of ancillary services bought by the ISO should be determined in an integrated and economic way. System security constraints should be met by procuring the least-cost mix of the several ancillary services. For example, the ISO should be able to substitute among types of reserves when a more flexible type is available at a lower price. When energy prices are below reserves prices, energy too should be considered in the mix. Furthermore when some Ancillary Services' prices are very high, the ISO should continue to make the judgment to purchase less of them, as it apparently did for Replacement Reserves when the price would have reached $10,000 per MW.

Third, the current market problems are sufficiently severe that they call for short-term intervention in the market, such as price caps. This will reduce deleterious market outcomes and provide "breathing room" for the development and introduction of long-term improvements. If generators in the Ancillary Services markets have and exercise considerable market power in the short run it will induce inefficient behavior that will spill over to the energy market. Since the Day-ahead energy market clears before Ancillary Services bids are submitted, a firm wishing to bid in the Ancillary Services markets will have to offer less capacity in the Day-ahead market. Although most of the time such a bid might earn little, the prospect of a lottery-type win for a few hours in one or another of the reserve markets could suffice to make the strategy worthwhile. While we expect that prices would eventually equilibrate on average in the different markets, they would do so only with considerable distortion among the various markets. Unit commitments and other decisions would be distorted by the inaccurate price signals. Furthermore, allowing the exercise of unbridled market power could lead to substantial wealth transfers and cause political pressure for re-regulation, thereby undermining the possibility of having successful markets in the long term. In short, the Committee is persuaded of the need for short-term market interventions, perhaps in the form of price caps, to cope with serious, market-impairing structural problems.

It is important, however, to minimize the long-term effects of any short-term intervention that is made to cope with such market power. For example, the introduction of price caps may impede future entry if potential entrants worry about the possible imposition of additional caps. The extenuating circumstances justifying the intervention should be made clear and distinguished from the ordinary course of market events in a well-functioning market, and the temporary character of the intervention should be emphasized. Maintaining the credibility of the market and its institutions is essential.

The price cap level, if that is the intervention chosen, must be carefully selected. The price cap needs to be set at a level that will provide the entry that we seek as the long-term solution to the structural problem. Given the linkages among markets, a price cap imposed on one ancillary service market will have an effect on the others and on the several energy markets as well. A cap that is too high or too low may distort behavior in one of those complementary markets. In particular, in setting the price cap, and comparing it with energy prices, it is important to bear in mind that Ancillary Services give an option to buy energy at the real-time price.

Finally, although the Committee believes that some short-term market interventions, perhaps in the form of price caps, are appropriate, it believes that low, participant-specific price caps consisting of cost-based rates for Ancillary Services are inappropriate. The cost-based -rate rules that are still in effect for some participants set the prices for those suppliers well below the prices that generally clear the energy markets during times of high demand. Thus, if those cost-based rates are imposed on a participant, that agent has an incentive to not offer capacity to Ancillary Services and instead to sell all its capacity in one of the energy markets. Although this restrains prices in the energy markets, it does so at the cost of distorting the signals about the relative value of ancillary services and energy. With cost-based caps imposed on some participants, inefficient quantities are offered to the Ancillary Services markets. This in turn could lead the ISO to resort to mandatory orders to generators to provide such services and further distortions of participant behavior and of prices. We recommend removing the cost-based rate caps that remain in effect.

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Committee on Governmental Affairs
EXHIBIT #A-52

August 17, 1998

The Honorable David P. Boergers
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: AES Redondo Beach L.L.C., et al., Docket Nos. ER98-2843-001, ER98-2844-001, ER98-2883-001 (Not Consolidated), ER98-2971-001, ER98-2972-001 (Not Consolidated), ER98-2977-001, EL98-62-000

Dear Secretary Boergers:

The California Power Exchange Corporation ("PX") respectfully submits this filing containing a copy of the Report on Market Issues in the California Power Exchange Energy Markets prepared by the PX Market Monitoring Committee pursuant to the Commission's order of July 17, 1998 in the above captioned dockets.

The PX Market Monitoring Committee believes that this submittal should comport with the Commission's requirements.

Respectfully submitted,

Reinier Lock/

Reinier Lock
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Power Exchange Corporation

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CERTIFICATE OF SERVICE

I hereby certify I that have this day served the foregoing submittal upon each person designated on the official service list compiled by the Secretary in the above referenced Dockets, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010 (1997).

Dated at Washington, D.C., this 17th day of August, 1998.

Erica Kairis

Report on Market Issues in the California Power Exchange Energy Markets

Prepared for the
Federal Energy Regulatory Commission

by
The Market Monitoring Committee
of the California Power Exchange

Roger E. Bohn
Alvin K. Klevorick, Chair
Charles G. Stalon

August 17, 1998

I. Introduction

On July 17, 1998 the Federal Energy Regulatory Commission (FERC) issued an order accepting the proposal by the California Independent System Operator (ISO) to limit temporarily the prices the ISO will pay to bidders that had been granted authority to set market-based rates for Ancillary Services. In addition to granting that authority to the ISO, FERC directed the ISO Market Surveillance Committee and the California Power Exchange (PX) Market Monitoring Committee to conduct independent studies and to file reports with the Commission within thirty days of the date of the order.

The studies were to examine "the bidding behaviors and structural characteristics of the markets that they [the Committees] each administer and to further clarify the causes of the perceived market concerns in the pleadings." Those concerns, expressed in pleadings by the ISO and Southern California Edison (SoCal Edison), were directed at the performance of the ISO markets for Ancillary Services and especially Replacement Reserves in early July. At issue, in particular, were dramatic price spikes in the price for Replacement Reserve Capacity and insufficient bids in that market and other reserve markets. The FERC expressed special interest in "how the workings of the California market and activity in the generation market affected the prices in the Ancillary Service and Replacement Reserve markets," and its interest presumably extends to the impact of activity in the ISO markets on the PX energy markets. In addition, the FERC directed that the ISO and PX market monitoring committees should address how "phase-in plans implementing new procedures such as the hour-ahead market" will affect PX and ISO markets.

The PX Market Monitoring Committee is engaged in an ongoing analysis of the structure, behavior, and performance of the PX day-ahead energy market, and it is beginning a similar study of the PX hour-ahead market, which commenced operation only on July 30th. In this report, the Committee draws on its ongoing study and the associated work of the PX Compliance Unit staff to respond to the FERC's inquiries. To answer the Commission's specific questions about interdependence of the PX and ISO markets, the Market Monitoring Committee has examined bidding behavior and market performance in the PX energy market especially during July and early August. The Committee emphasizes that the time constraints on the preparation of the report have limited the depth and scope of quantitative analysis that could be undertaken. The members of the Committee regard this report as part of a continuing examination and analysis of the PX markets, directed at the maintenance of competitive and efficient energy markets in California, rather than as a discrete, time-limited study.

In the next section of the report we delineate the boundaries of our analysis and characterize the product we have tried to deliver. Section III provides a review of the structure and performance of the PX day-ahead energy market from its inception to the present. Relevant characteristics of the Ancillary Services markets are also discussed. (In this report, we use

"Ancillary Services" in the generic sense, including Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves.) In Section IV we present our analysis of bidding behavior in the PX market with special attention to July including the period that generated concerns about the ISO Ancillary Services markets. Section V contains our discussion of the interactions between the PX and ISO markets. We conclude, in Section VI, with implications that we draw from our analysis.

II. The Character and Boundaries of Our Analysis

First, our report focuses on the PX market for energy and, due to the very recent introduction of the hour-ahead market, primarily on the day-ahead market. We discuss and comment on the ISO markets only to the degree that there is reason to inquire about how developments in those markets may have an impact on the PX market and vice versa. In particular, it is fundamental to recognize that the capacity available for the ISO markets and for the PX markets comes from the same generating capacity. Capacity sold in one market means less capacity that can be sold in other markets, thereby driving up prices in the latter. Therefore, we would expect a close relationship among the different markets.

Second, we have written a descriptive, analytical report. We are not assessing whether particular participants behaved well or behaved badly. Rather, we attempt to analyze how they have behaved, based on historical data, and how we might expect them to behave, based on the market rules and their incentives as we understand them. Our report is normative only to the extent that our analysis will lead us to recommend one or another policy measure.

Third, it is essential to keep in mind just how new these markets are. They are still developing and evolving in important ways. We expect behavior to change as participants gain experience; as new markets open, such as the hour-ahead market; as supply and demand change due to seasonal forces and market pressures; and as unanticipated events occur. Over time we would expect the sophistication of both the demand and supply participants to increase, and their behaviors to change. This continued evolution should be recognized when considering policy changes. Problems we diagnose now may be inherent in the market or they may be transitional difficulties.

Fourth, the information we have is limited in important ways. We do not have data on some transactions outside the PX markets, especially bilateral sales (made outside the Power Exchange market) and Reliability Must Run transactions. As a consequence, we cannot accurately characterize the degree to which some of the PX market participants are using dedicated capacity as a strategic instrument.

III. Overview of Markets and Operations

This section provides an overview of California's electricity market structure and a summary of PX operations from the opening of the market on April 1, 1998 through August 11, 1998.

PX Market Descriptions

The PX operates two separate energy markets: a day-ahead energy market and an hour-ahead energy market. The PX has been operating its day-ahead energy market throughout the four months since restructuring was implemented, while the hour-ahead energy market commenced operations on July 30, 1998.

PX Day-Ahead Market

In the day-ahead market, PX Participants submit portfolio bids to buy and sell energy for each hour of the succeeding day. These portfolio bids, which must be submitted to the PX by 7:00 a.m. on the day prior to the actual dispatch day, are used by the PX to derive aggregate supply and demand curves from which the PX establishes an unconstrained market clearing price and quantity for each hour. Following the conclusion of the day-ahead auction, successful bidders provide the PX with Initial Preferred Schedules that reflect the quantities awarded in the auction process. These schedules specify the quantity and location of loads and supplies within the grid. The PX provides these schedules, which in aggregate must be balanced with respect to supply and demand in each hour, to the ISO by 10:00 a.m. on the day prior to the dispatch day. Other Scheduling Coordinators, representing bilateral transactions, submit their balanced schedules to the ISO in a similar manner.

These schedules also include Participants' Ancillary Services Bids and Schedule Adjustment Bids (for inter-zonal transmission congestion). Upon receiving the resource schedules from Scheduling Coordinators, the ISO conducts its Ancillary Services auction and performs congestion management, thereby, making any necessary adjustments to the Initial Preferred Schedules based on participants' bids. The ISO then issues Final Day-Ahead Schedules, including the schedules for Ancillary Services, by approximately 1:00 p.m. each day, and publishes final transmission Usage Charge rates if transmission congestion has occurred. The PX then calculates Zonal Market Clearing Prices based on its Participants' Schedule Adjustment Bids and the Usage Charge rates provided by the ISO.

PX Hour-Ahead Market

In the hour-ahead market, buyers and sellers are able to adjust the positions they received in the day-ahead market. This is especially useful to distribution utilities and electric service providers who may need to modify their day-ahead market positions when demand changes due to weather conditions or supply changes due to plant outages or line de-ratings. The PX hour-ahead market also provides benefits to bilateral market participants who may wish to adjust their day-ahead market positions. The PX hour-ahead market involves trading around-the-clock through 24 hourly auctions.

PX Schedule Coordination

In addition to operating the forward energy markets (day-ahead and hour-ahead), the PX also functions as a Scheduling Coordinator with responsibility for submitting balanced resource schedules to the ISO, providing real-time dispatch instructions to its Participants, and performing billing and settlements services for both the day-ahead and hour-ahead markets.

ISO Market Descriptions

The ISO operates the real-time Imbalance Energy market, the Ancillary Services market, and the Transmission Congestion Management market.

Imbalance Energy Market (Real-Time Market)

The ISO is responsible for balancing loads and resources in real-time. The ISO uses bids received in the Imbalance Energy market to increment and decrement resources as needed to maintain a system-wide energy balance. These bids include Supplemental Energy Bids, which Participants provide to the ISO up to one hour prior to the dispatch hour, as well as the energy bids submitted by Participants in conjunction with their Ancillary Services capacity bids, as described below. The Imbalance Energy market price is calculated in 10 minute intervals on an ex-post basis. This price is used to settle deviations between scheduled and actual quantities of supply and demand. A Participant that over-delivers relative to its scheduled quantity is paid the imbalance price, while a Participant that under-delivers relative to its scheduled quantity is charged this price.

Ancillary Services Markets

The ISO conducts four day-ahead and four hour-ahead auctions for Ancillary Services. These four Ancillary Services are: Regulation, Spinning Reserves, Non-Spinning Reserves, and Replacement Reserves. Each is a capacity-only market. Bidders must also include an energy bid with each capacity bid. The Energy Bids in the Regulation market are used for validation only while the Energy Bids for Spinning, Non-Spinning, and Replacement Reserves are used, along with Supplemental Energy bids, in the real-time Imbalance Energy market. In addition to these four Ancillary Service products, which are acquired through an hourly market-clearing auction process, the ISO also is responsible for acquiring Voltage Support/Reactive Supply and Black Start capability, which it procures though a longer term contracting process.

Transmission Congestion Management

The Transmission Congestion Management market operates on the basis of Schedule Adjustment Bids (SABs) provided to the ISO by Scheduling Coordinators. These SABs indicate the willingness of a Scheduling Coordinator to increment a resource if the price increases or decrement a resource if the price decreases (vice versa for demand and exports), and are an expression of the value that the Scheduling Coordinator places on obtaining inter-zonal transmission access. The ISO uses the SABs to adjust individual resource schedules to relieve congestion and calculate transmission congestion Usage Charge rates.

Table 1 shows the detailed operational timelines for the day-ahead and hour-ahead markets.

Table 1 Timeline for Day-Ahead and Hour-Ahead Markets[1]

Day-Ahead Timeline	Day-Ahead Activity
By 7:00 a.m.	Participants submit day-ahead portfolio energy supply bids and demand bids for each hour to the PX.
By 7:15 a.m.	PX conducts day-ahead energy auction and notifies successful bidders of hourly market-clearing prices and quantities.
By 9:20 a.m. (scheduled to move to 9:10 a.m., beginning August 23)	Participants submit Initial Preferred Schedules to the PX that provide details of the specific generating units and loads that fulfill the aggregate awards in the energy auction. In addition, Participants submit Schedule Adjustment Bids for inter-zonal transmission access.
By 9:30 a.m.	Participants submit to the PX bids for Ancillary Services (regulation, spinning reserves, non-spinning reserves, and replacement reserves).
By 10:00 a.m.	PX and other Scheduling Coordinators (SCs) submit their Participants' Initial Preferred Schedules to the ISO, along with their Participants' Schedule Adjustment Bids and Ancillary Services Bids.
By 11:00 a.m.	ISO completes first iteration of inter-zonal congestion management. If there is no inter-zonal congestion, ISO issues Final Day-Ahead Schedules, including the schedules for Ancillary Services selected in the ISO's Ancillary Services auction. If there is congestion, ISO provides the PX and other SCs with the estimated Day-Ahead Usage Charges, a Suggested Adjusted Day-Ahead Schedule, and a preliminary schedule for Ancillary Services.
By 12:00 noon	If there is inter-zonal congestion, PX and other SCs submit to the ISO their Revised Day-Ahead Schedules, in response to the ISO's Suggested Adjusted Day-Ahead Schedules.
By 1:00 p.m.	ISO performs second iteration of congestion management and provides the PX and other SCs with Final Day-Ahead Schedules, including the schedules for Ancillary Services, and issues final Day-Ahead Usage Charge rates.
By 1:15 p.m.	PX and other SCs send their Participants the Final Day-Ahead Schedules, including the schedules for Ancillary Services, and the Final Day-Ahead Usage Charge rates. PX calculates zonal market-clearing prices.
By 1:30 p.m. (approx.)	ISO determines if there are any deficiencies in the results of the ancillary services auctions and evaluates Reliability Must-Run requirements relative to Final Schedules.
By 5:00 p.m. (approx.)	ISO notifies market participants of any changes in Final Day-Ahead Schedules resulting from ancillary services shortfall and Reliability Must-Run generation requirements.
Hour-Ahead Timeline	**Hour-Ahead Activity**
Not later than 3 hours prior to the dispatch hour	Participants submit energy supply and demand bids to the PX (bids are resource specific and are relative to Day-Ahead Final Schedules).
Not later than 2 hours, 50 minutes prior to dispatch	PX calculates market clearing prices and quantities, and determines Preferred Schedules.
Not later than 2 hours prior to the dispatch hour	Participants submit Schedule Adjustment Bids and Ancillary Services Bids to the PX, which in turn, submits the Preferred Schedules, Schedule Adjustment Bids, and Ancillary Services Bids to the ISO.
Not later than 1 hour prior to dispatch hour	ISO performs congestion management and conducts its Ancillary Services auction. ISO provides PX and other SCs with Final Hour-Ahead Schedules, including schedules for Ancillary Services, and final Usage Charge rates. PX, in turn, transmits this information to its Participants.
Prior to dispatch hour	PX calculates and publishes Zonal Market Clearing Prices.
Real-Time Timeline	**Real-Time Activity**
Not later than 60 minutes prior to the start of hour	Participants provide Supplemental Energy Bids to the PX and other SCs.
Not later than 45 minutes prior to the start of hour	PX and other SCs submit Supplemental Energy Bids to the ISO for use in the real-time market.

[1] Target timetable; actual performance varies depending on circumstances.

Bidding in multiple markets

Most participants will be eligible to bid in several of the markets. The exact sequence of bids and responses affects how they will do so. Prior to their 7 a.m. day-ahead bids, generators must make an approximate decision about the split between what they want to offer in the day-ahead and Ancillary Services markets. Bids in the day-ahead energy market are accepted before bids in the AS market need to be placed. If generators want to offer a larger quantity in any AS market, they must offer a smaller quantity in the day-ahead market. They can implement this directly, or they can offer the smaller quantity at "reasonable" prices, and then offer the rest at very high prices. Once the day-ahead market results are revealed at 7:15 a.m., the generators know how much capacity they can offer to the AS markets.

The method the ISO uses for sequencing the four AS markets also is important. Generators can bid simultaneously in all four markets, according to the following hierarchy:

- Regulation
- Spinning reserves
- Non-spinning reserves
- Replacement reserves.

The ISO resolves the four markets in order. Any bid in a lower numbered market that is not accepted is automatically assumed to be a bid in the higher numbered markets. In this way, the generator does not have to enter separate bids in each market, and the same MW of physical capacity can be entered simultaneously into all four markets. If some of the MW are not purchased in the spinning reserves market, for example, they are automatically offered to serve the non-spinning or replacement reserves markets. Thus, unlike the choice between day-ahead and Ancillary Services markets, participants do not need to decide in detail to which AS market they would like to offer, except insofar as their units are physically constrained to one or another market.

This ability to bid well above the predicted market clearing renders problematic the interpretation of the "quantity" a participant bids into the market. For example, the ISO's motion requesting a stay of the FERC's June 30 and July 10 orders states (p 25):

> Moreover, the Ancillary Services markets are already depressed by the bidding rules that govern the Utility Distribution Companies. They must first bid their available generation into the Power Exchange. They are not free to hold it out for the Ancillary Services auctions and can participate in those auctions only if and to the extent that their bids are not accepted by the Power Exchange.

This is technically correct, but irrelevant. By bidding a price of $250/MWh or higher for some of its capacity, any participant including an IOU can be almost assured that the capacity will not be accepted in the day-ahead PX market. The capacity will therefore be available for bidding in later markets, including the Ancillary Services and real-time markets. Of course, if the IOU is limited to cost-based rates for Ancillary Services, it will probably prefer to sell in the energy markets, but the choice is its own. In our analysis, we have generally interpreted offers above $250/MWh as the participant's effectively withdrawing capacity above that price from the day-ahead market.

Market Performance

During the period April 1 through August 11, 1998, the PX has successfully run its day-ahead energy market and published hourly market clearing prices and quantities every day. The hour-ahead market opened recently and is functioning properly as well. The overall trends in the PX markets during this period are summarized below.

Market Overview

The California electricity market is enormous, representing approximately $22 billion in annual revenues and 246,000 GWh of annual energy consumption, roughly 10% of the total U.S. market. The three major investor-owned utilities (Southern California Edison, Pacific Gas & Electric, and San Diego Gas & Electric) account for approximately 70% of the total California electricity market on an energy consumption basis, with the balance of the market served by municipal and governmental entities. Since the market opened, the PX share of the restructured California electricity market has been approximately 88%.

PX Participants include investor-owned utilities, Federal and municipal entities, independent power producers, and power marketers, from both within and outside California. There are approximately 45 Participants certified to trade in the PX markets, with about 35 Participants active in the markets on any given day. In addition, there are about 20 entities currently in the certification process. As a result of generation divestiture, the California IOUs' share of the PX supply market has declined from about 93% in the early months of the market to about 85% in July.[2] On the demand side, the California IOUs are the dominant players within the PX, representing about 95% of the load in the day-ahead energy market.

Demand

While population and economic activity are major underlying factors determining demand for electricity, weather is the primary determinant of seasonal and daily variations in load. Temperature patterns and deviations from the expected seasonal trends throughout the Western System are important for the California market. California and the inland Southwest have desert climates with substantial air conditioning load, whereas the Northwest and Northern Rockies have more moderate summer temperatures, but higher heating loads in the winter.

Temperatures throughout the region during April were mild and continued moderate through May and June. As a result, air conditioning loads in the California market were somewhat lower than average. Temperatures in the Northwest were also below average with more heating degree days in April, May and June than normal, thus increasing nighttime heating requirements. In late June and early July, temperatures began to increase somewhat and

[2] These percentages are for generation bid by the IOUs. Much of this generation is owned by other parties and bid in at a zero price under provisions such as those for qualifying facilities.

finally gave way to high temperatures in mid-July through early August. Electricity demand in late July and early August was up throughout the region, in some cases to record levels. Since this heat wave had an impact on the Southwest and the Northwest as well as on California, demand increased throughout the region.

Table 2 shows monthly information on PX market clearing quantities. As expected, the difference between the maximum hourly and minimum hourly clearing quantities has significantly increased since the Spring, from about 10,000 MW to 18,000 MW, thereby increasing the need for peaking resources.

Table 2 PX Market Clearing Quantities

Month	Maximum Hourly MCQ (Megawatts)	Minimum Hourly MCQ (Megawatts)	Average Hourly MCQ (Megawatts)
April	24,847	14,657	19,914
May	23,007	14,542	19,050
June	28,499	15,683	21,398
July	35,774	16,993	25,393
August*	36,376	18,075	26,784

* As of August 11.

Supply

Generation capacity in the Western region is ample, with total generation in excess of peak demands. The Western configuration is fortuitous with winter heavy load in the Northwest and Northern Rockies counterbalancing heavy summer loads in California and the Southwest. Because of the importance of the seasonal north to south interregional flows, transmission curtailments or de-ratings on the Pacific Interties can have an impact on generation supply to the California market. Similarly, unit outages, either scheduled for maintenance or unplanned, affect supply availability and thus prices in the California market.

Supply conditions were generally robust during the April through mid-July period. Hydro generation conditions in the Northwest have been generally good, with moderate impacts from spill requirements associated with salmon restoration efforts. Northern California hydroelectric generation has been abundant as the result of higher than usual snow pack and moderate temperatures.

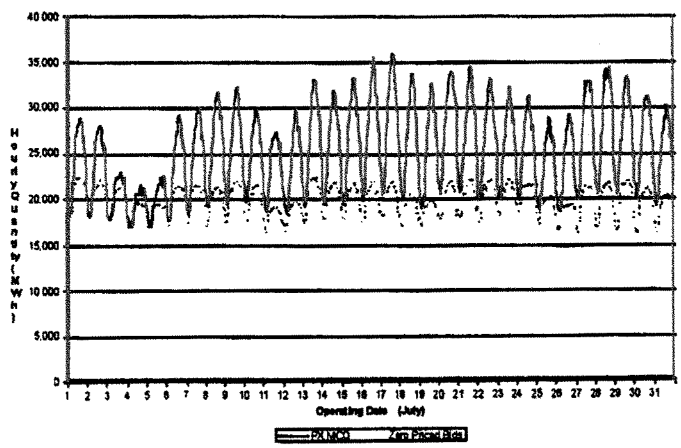
Pacific Intertie curtailments limiting the flow of power to California in July, coupled with hydro generation concerns in the Northwest in late July, contributed to upward price pressures during this period. Since late July, extreme temperatures in the Southwest and Northwest, combined with forced outages at key plants, pushed peak prices upward and led to voluntary load curtailments in several hours.

Power plant divestitures have also had an impact on the supply picture. Since the opening of the market, the California IOUs have divested approximately 12,000 MW of generation resources, mostly natural gas-fired plants. Four separate companies acquired the majority of this capacity and are now actively bidding these resources into the California market and other markets in the western states, as discussed in Section IV.

Regulatory Must-Take (RMT) generation is another important factor in the PX market. RMT resources, which include nuclear units, Qualifying Facilities, and run-of-the-river hydro, are bid into the PX at $0/MWh to ensure their selection in the auction process. Other resources, which may not be classified as RMT but which may for operational reasons want to be assured of being dispatched, may also bid into the PX at $0/MWh. These resources typically account for approximately 20,000 MW of capacity. At lower demand levels, these resources can set the market clearing price at zero, as happened in many hours in May and early June. As demand levels increased in July and August, coal units and natural gas units determined the market clearing price.

For example, in June, average hourly PX demand was 21,400 MWh, while the average hourly quantity of generation bid into the PX at zero price was 19,600 MWh, or 92% of PX market demand. In July, average hourly demand increased to 25,400 MWh, while the quantity of zero price generation bids was 19,800 MWh, or 78% of PX demand. In August, the fraction of zero price generation bids decreased to 73% of PX demand. As expected, the percentage of zero price energy bid into the PX relative to total PX demand is higher in the off-peak periods and lower in the on-peak periods. See Figure 1.

Figure 1 Zero Priced Bids vs Total PX Market Clearing Quantity, July 1998



The implication of the high volumes of zero priced bids is that the energy markets are "thinner" than they first appear. For example, suppose energy demand is 30,000 MW, zero bids are 20,000 MW, and one firm controls 3,000 MW of gas-fired capacity. It is more accurate to view this firm as having capacity equal to 30% of the price setting portion of the supply base, rather than 10% of the overall market.

Prices

The following discussion of PX market prices covers the period April 1 through August 11, 1998, and concerns PX unconstrained market clearing prices. The impact of transmission congestion on the unconstrained market clearing prices is discussed in a subsequent section.

We can roughly divide the period since the market opening into Spring (April, May, June), and July/August. Behavior of prices during the two periods was distinctly different. Table 3 summarizes the prices each month and shows the large rise from June to July.

Table 3 Unconstrained PX Market Clearing Prices ($/MWh)

Month	Minimum	Maximum	Average	Average Hours 7-22 (on peak)	Average Off-Peak hours
April	0.00	36.74	22.64	25.54	17.33
May	0.00	37.37	11.63	16.43	6.18
June	0.00	38.02	12.09	16.94	5.21
July	0.00	151.10	32.42	41.08	21.49
August*	6.79	163.01	43.13	60.93	25.50

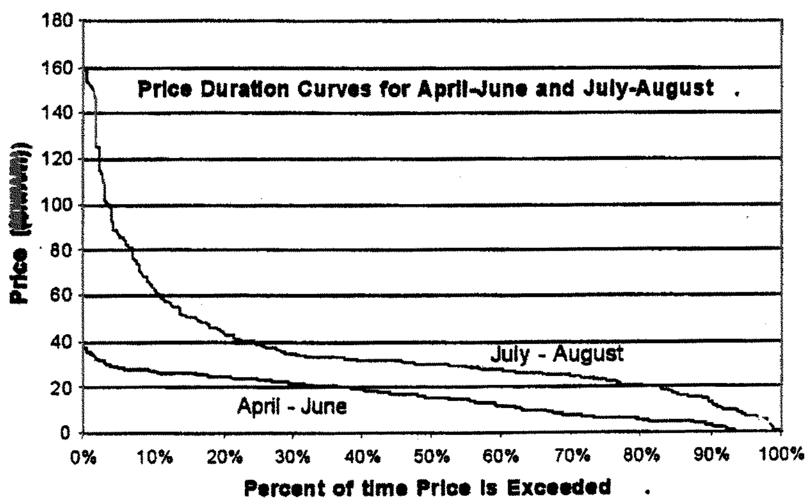
* Through August 11.

In April, the PX average hourly price was about $23/MWh, with hourly prices varying during the month from a low of $0/MWh for three hours, to a high of about $37/MWh, as shown in Table 3. In May and June, average hourly prices fell significantly from the April level, to about $12/MWh, due to moderate demand caused by mild temperatures and substantial hydro availability in Northern California. The market clearing price was $0/MWh for 43 hours in May and 87 hours in June.

Prices began to rise in mid-July as summer temperatures developed and demand levels rose. The PX hourly average price rose to $32/MWh in July and $43/MWh in August, with natural gas units setting the market-clearing price in most hours. Peak prices rose significantly as much of the West went through a severe heat wave with several control areas in California reporting all-time record loads. The maximum hourly price rose to $151/MWh in July and $163/MWh in August. In addition, zero prices virtually disappeared, with only nine hours of zero prices in July and no hours of zero prices in August so far.

Figure 2 is a price duration curve that shows the percentage of time that prices exceeded a particular level. The lower curve is for the period April 1 through June 30 while the upper one is for the higher demand period of July 1 through August 11, and illustrates the dramatic change between the periods. As shown in Figure 2, the maximum price through June did not exceed \$40/MWh and price was zero about 6 percent of the time. In July-August, however, prices were above \$40/MWh about 25% of the time, and price was zero only briefly.

Figure 2 Comparison of Price-Duration Curves



Price volatility

Figure 3 shows the relationship between the PX market clearing price and quantity for the period April 1 through June 30, 1998. As shown, the maximum hourly quantity was less than 30,000 MWh throughout the three month period and the maximum price less than \$40/MWh, and there were significant variations in price for a given quantity. Figure 4 presents equivalent information for the period July 1 through August 11, 1998. It shows that the shape of the price-quantity relationship changed significantly as market clearing quantities (MCQ) exceed 30,000 MWh, as average prices rise steeply with market quantity above 30,000.

Figure 3 Market Clearing Price and Quantity for the Period April 1 – June 30

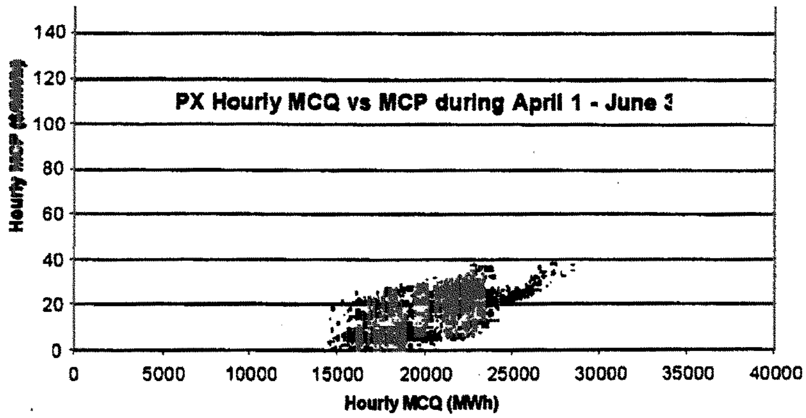
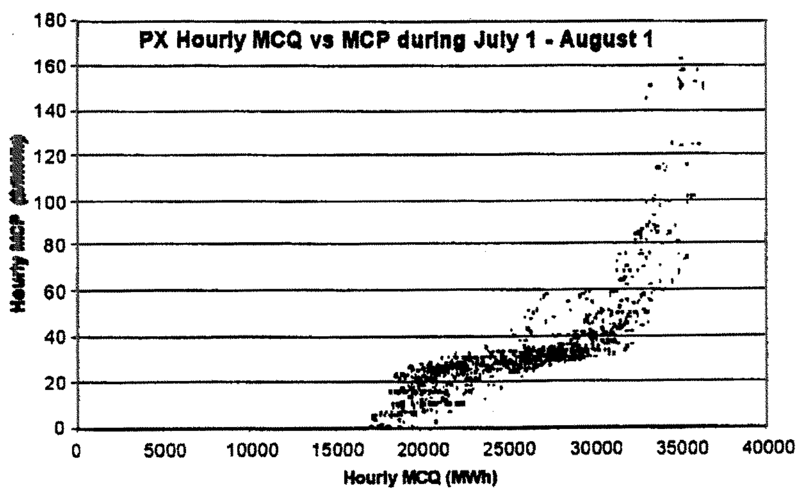


Figure 4 Market Clearing Price and Quantity for the Period July 1 – August 11



Congestion

Congestion on the major transmission paths has increased as electricity demand levels have increased. Table 4 shows the number of hours of congestion on the major transmission paths, while Table 5 shows the resulting impact of such congestion on the PX unconstrained market clearing prices.

Table 4 Congestion charges

Month	Transmission Path	Number of Hours Congested	ISO Transmission Usage Charges ($/MWh)		
			Minimum	Average	Maximum
April	So. Calif – No. Calif	0	0.00	0.00	0.00
	Calif – Oregon	1	4.14	4.14	4.14
	Calif – NOB	3	250.00	250.00	250.00
	Calif – Arizona	0	0.00	0.00	0.00
May	So. Calif – No. Calif	0	0.00	0.00	0.00
	Calif – Oregon	131	0.10	9.34	50.00
	Calif – NOB	127	0.01	40.80	250.00
	Calif – Arizona	0	0.00	0.00	0.00
June	So. Calif – No. Calif	59	0.14	3.65	25.90
	Calif – Oregon	119	0.02	4.71	14.30
	Calif – NOB	82	0.01	2.91	12.51
	Calif – Arizona	0	0.00	0.00	0.00
July	So. Calif – No. Calif	62	0.02	12.45	76.25
	Calif – Oregon	199	1.01	17.78	58.01
	Calif – NOB	95	0.01	11.51	11.51
	Calif – Arizona	0	0.00	0.00	0.00
August*	So. Calif – No. Calif	35	0.70	9.55	23.60
	Calif – Oregon	23	0.63	2.29	3.94
	Calif – NOB	7	1.87	27.91	80.86
	Calif – Arizona	0	0.00	0.00	0.00

* As of August 7.

In April and May, there was no congestion on the main transmission link between northern and southern California (Path 15, linking zones NP15 and SP15). In June and July, congestion on this path occurred in a total of 121 hours, or 8% of the time. On the California-Oregon Intertie (Northwest 1), one of two major transmission links between California and the Northwest, congestion occurred in only one hour during April. In May through July, however, congestion on this path occurred an average of 150 hours per month. On the California-NOB link, the other major transmission link to the Northwest, congestion occurred in only three hours in April, and an average of 100 hours per month during May through July. There was no congestion between California and Arizona.

The vast majority of electricity demand in California occurs in Zones NP15 and SP 15, Northern and Southern California respectively. As a result of congestion, the average PX unconstrained market clearing price in NP 15 increased an average of $1/MWh during the congested hours in the period May through July. During this same period, the average unconstrained price in SP 15 increased approximately $2/MWh during the congested hours.

Table 5 Average Price Impact on NP15 and SP15 Due to Congestion

Month	Price Impact Hours	Unconstrained Market Price ($/MWh)	Average Price Impact in SP15 ($/MWh)	Average Price Impact in NP15 ($/MWh)
April	0	n/a	n/a	n/a
May	162	16.85	1.86	1.86
June	150	21.84	1.20	0.80
July	199	42.28	2.75	0.43
August*	68	48.49	-1.41	2.18

* As of August 7.

Comparison with bilateral markets

The PX regularly compares its day-ahead energy market prices with those occurring in bilateral markets, as shown in Table 6[3]. Such comparisons must be viewed carefully since the PX prices are derived from individual hourly auctions, whereas bilateral market prices represent a relatively small volume of energy traded in aggregate on-peak and off-peak blocks, and are determined based on a survey of market participants. Nonetheless, the comparisons are tracked closely by the PX. The two primary hubs for bilateral trades in the California market are at the California/Oregon border (COB) and at the California/Arizona border (Palo Verde).

[3] Source of bilateral market prices: Energy Market Report.

Table 6 Comparison of PX Unconstrained Prices with Bilateral Market Prices ($/MWh)

	On-Peak				Off-Peak		
Month	PX	COB/ NOB	Palo Verde		PX	COB/ NOB	Palo Verde
April	25.54	25.14	25.22		17.33	16.33	14.96
May	16.43	14.82	19.62		6.18	7.60	7.97
June	16.94	15.65	20.68		5.21	5.97	7.28
July	41.08	31.39	43.81		21.49	17.02	17.48
August*	60.93	55.31	55.44		25.50	27.91	24.80

* As of August 11.

Comparison with real-time prices

As shown in Table 7, PX average hourly prices have been slightly above ISO real-time prices, although real-time prices have been more volatile, as would be expected. During the period April 1 through August 11, the PX average hourly price has been $21.67/MWh with a standard deviation of $18.80/MWh, while the average ISO real-time price has been $18.29/MWh with a standard deviation of $23.62/MWh.

Table 7 Comparison of PX Unconstrained Market and ISO Real-Time Prices ($/MWh)

Month	PX Average Hourly Day-Ahead	ISO Average Hourly Real-Time Price	PX Price Standard Deviation	ISO Price Standard Deviation
April	22.64	20.49	6.56	11.26
May	11.63	9.33	7.68	10.40
June	12.09	8.36	9.36	10.91
July	32.42	27.83	20.71	29.69
August*	43.13	42.61	34.97	48.75

As of August 11.

PX Hour-Ahead Market

The PX hour-ahead market has been in operation only a couple of weeks and has had low volumes during this initial period. Prices have exhibited significant volatility, as expected and as does the real-time market. The transaction volume in the hour-ahead market will likely increase as market participants gain additional experience with its operation.

IV. Behavior of the key participants in the markets

In this section we describe and analyze the behavior of the most relevant generating companies. These companies own or at least control gas-fired generating units. Their units play a crucial role since they provide about 17,000 MW of gas-fired capacity, which comes into play as demand rises above the level that can be met by baseload units. During the afternoon hours in July the zero-bid capacity, mainly from utilities, was greater than 20,000 MW while total demand was between 29,000 and 35,000MW. (See the discussion of regulatory must-take in Section III.) Therefore units of the "key participants" should generally be at or near the margin and always play a role in determining the market-clearing price during these hours. Our analysis, below, of the frequency with which particular participants comprise the marginal supply supports this characterization.

By examining the behavior of these generators we hope to understand better the behavior of prices in individual markets as well as the issue of spillovers from one market to the next.

We have limited our detailed analysis to ten weekdays in July: July 6-10 and July 27-31. During the first of these weeks, Ancillary Services prices were not capped, and Replacement Reserve prices reached $5000 per MW for 3 hours. During the July 27-31 period, Ancillary Services prices were capped at $250 per MW. Three of the four Ancillary Services markets hit this cap during some hours of the week. We examined the hours from 12 to 20 (11 a.m. to 8 p.m.) each day. These are the hours with the highest demands and highest prices in both Ancillary Services and energy markets.

Summary of the key participants

Nameplate capacity of the main gas-fired plant operators is displayed in Table 8. The first four owners are new participants in the California market, who purchased plants from the IOUs. The last two owners are Investor-Owned Utilities (IOUs). This table does not include 280 MW of combustion turbines owned by SDG&E, 280 MW of gas units owned by Thermo Ecotek, and various non-gas units. The table also does not include out-of-state participants, who may at times provide significant energy. Hydro units can also play a role in determining prices, particularly the 1200MW of pumped hydro owned by PG&E.

Table 8 Ownership and size of intermediate gas units

Owner	Abbreviation	Capacity (MW)	Share
AES (Williams)	WESC	3956	23%
Houston Industries	NES	3776	22%
NRG Energy/Destec	ECI	1550	9%
Duke Energy	DETM	2645	16%
Sum of these four	Independents	12,200	70%
PG&E	PGPG	3488	20%
San Diego Gas & Elec.	SDGE	1644	10%
Total		17,100	100%

Source: PX data.

Hypotheses concerning behavior of key participants

If a generator were acting like a perfect price taker, we would expect it to bid each hour with a supply curve approximately equal to the marginal generating cost up to the capacity of its units. For example, with delivered gas prices now about $3 per MMBtu, a generator with a heat rate of 10,000 Btu/kwh would bid slightly above $30 per MWh. Prices would rise above the $30 level whenever total demand, including Ancillary Services demand, exceeded the capacity of baseload (zero bid price) plus gas units. At these times, gas turbines and other special technologies would comprise the marginal supply and, together with demand, jointly determine the price. A unit with a marginal running cost of $30/MWh would then receive contributions to fixed costs whenever prices are above $30 for any reason.

We consider this the "competitive behavior model." Another important attribute of this model is that the quantity offered by each generator should add up to its capacity. But during the two July weeks we examined, the bidding of the key participants did not always fit this competitive behavior model. The firms behaved rather differently from each other, but only a few followed the predictions of the competitive model just sketched.

The behavior of the six key participants in the PX day-ahead market in July departed in two main ways from the competitive model. First, they almost never bid to supply their entire generating capacity in the PX market. Second, they often bid capacity at prices well above $30/MWh. In fact some firms bid some of their capacity at prices above $100/MWh during some hours.

For any given generating company and hour, there are at least five possible explanations why its bid quantity in the PX day-ahead market might total less than its capacity. They are:

- The participant expects one or more units to be unavailable.
- It has a bilateral contract to sell energy.
- It planned to sell capacity in one of the ISO markets. (Recall that the bids for the PX day-ahead market must be placed before bids in the Ancillary Services and other markets.)
- The participant is trying to push prices up.
- The participant hopes that by not bidding a unit, it will be called as a Reliability Must Run unit, and it will receive a higher price than it would have received in a competitive market.

With these explanations in mind, plus the default hypothesis of competitive behavior, we examined the behavior of each key participant during the hours from 12 to 20 in the weeks of July 6-10 and 27-31. Unfortunately we had very little information about the first two explanations: unit availability and bilateral contracts. This limits the inferences we can draw.

Observed behavior of participants

Different participants followed different patterns of bidding during the ten days and 90 hours we examined in detail. Several appeared to be pure price-takers. They bid a flat supply curve at a price approximately equal to the marginal cost of a gas-fired unit. Others used very elaborate bid curves that varied by hour and day. Not surprisingly, the latter were often the marginal price setters.

Some of the more elaborate bidding mechanisms used at different times by different participants included the following:

- Finely differentiated upward sloping supply curve.
- Hour to hour changes in the supply curve, shifting the curve to the left (less energy offered at a given price) at times when prices were likely to be higher.
- Day to day changes in the supply curve.
- Extensive bidding in Ancillary Services markets.
- Apparent adjusting of Ancillary Services and supplemental energy (real time) offers in response to sales in the day-ahead market.

We emphasize that without a full econometric model to explain bidding behavior -- one that accounts appropriately for exogenous factors and individual units -- and more data, we cannot draw firm conclusions from this examination. In particular, we cannot easily tell whether a given participant is "withholding" some of its capacity to force prices up or to induce the ISO to call a unit for Reliability Must Run status. Recall, specifically, the gaps in our data on bilateral contracts. Thus although we often observed PX-market offers and sales significantly below nameplate capacity, at this point no definite inferences can be drawn.

Our limited examination of bidding behavior, however, does provide considerable suggestive evidence that the energy markets are at times thin and not fully competitive. Therefore, any actions taken by the ISO to improve the Ancillary Services markets should be carefully scrutinized to be sure they do not adversely affect the energy markets. This is especially important since the volumes of the energy markets are about ten times larger than the volumes in the Ancillary Services markets.

It is also possible to *over-offer* capacity. That is, a participant can make AS bids by 9AM such that AS bids plus day-ahead sales exceed its capacity. For example, one afternoon a participant sold 80 percent of its capacity in the day-ahead market, and then bid 50 percent of its capacity in the AS markets. Because of its supply curve (bid prices) about half its Ancillary Services bids were purchased. This led to total commitments of 106% of its capacity. There is nothing necessarily wrong with this if the participant is willing to "buy back" its day-ahead energy sales in the hourly, real-time, or bilateral markets.

Who determined prices?

Since we have data on individual supply curves (bids), we can engage in some sensitivity analysis to determine which participants had the most effect on prices. In essence we ask the question, "At the actual price-quantity intersections in the marketplace, which firms were the ones with the most power to alter price by altering their bids?" We estimated this by looking at the incremental supply curve of the marginal firms, recognizing that several firms might be on the margin to different degrees in the same hour. This gave us a measure "percent of incremental energy from participant x." In a perfectly competitive market with six identical participants, we would expect that each participant would provide approximately 17% of the incremental energy. We interpret a disproportionate share of one firm as meaning that it had a larger opportunity to influence prices. Whether such firms used that opportunity is a separate matter.

We examined the incremental firms over the period July 1 to August 10. Only "high priced hours," i.e. those over $75/MWh, were included in the calculation. There were 70 such hours. Of the approximately 30 sellers in the market, only four were important on the margin during these 70 hours. Not surprisingly in light of the differences in bidding behavior discussed above, we found substantial differences in who was on the margin at different prices. At prices from $75 to $100/MWh, incremental supply was divided rather evenly among four firms, with two of the six key participants almost never on the margin. At prices between $100 and $125, one firm was dominant with about three quarters of the incremental energy. When the price was above $125, a different firm was dominant with about three quarters of the incremental energy.[4]

We conclude from these share numbers that at certain levels in the aggregate supply curve, a very small number of firms had the effective ability to determine the prices. In essence they dominate a horizontal slice of the aggregate supply curve, and other firms have vertical supply curves in those price regions, or bid all their capacity at lower prices. At other levels, many firms are bidding with sloped supply curves, and no one firm dominates. The Market Monitoring Committee is concerned about market concentration issues, and will monitor it closely in the future.

V. Interactions between PX and ISO markets

The prices in three ISO Ancillary Services markets and in the PX Day-ahead market are shown in Figure 5, for hours 12 to 20 on the ten weekdays we studied. All prices are shown on the same scale, which illustrates the wide variations among markets and over time. Corresponding quantities are shown in Figure 6. We show Ancillary Services prices and quantities only for the SP15 region, which is the largest demand region and was moderately more subject to high prices than NP15. As the graphs show, different markets had high prices on different days. For example, in the energy market, during these ten days prices exceeded $100/MWh only on Tuesday July 28. That day, non-spinning reserve and replacement reserve hit their caps of $250/MW, while the price for spinning reserve was about $10.

[4]: We took 90% of the original MCPs and calculated the generation from each participant at this price and at the actual MCP. The difference we considered that firm's incremental generation. This number divided by total incremental generation was the share for that participant in that hour. We then took the weighted average share for a participant across all hours in the price range, using the hours' total increments as the weights. There were 42 hours with prices between $75 and $100, 14 hours between $100 and $125, and 14 hours over $125.

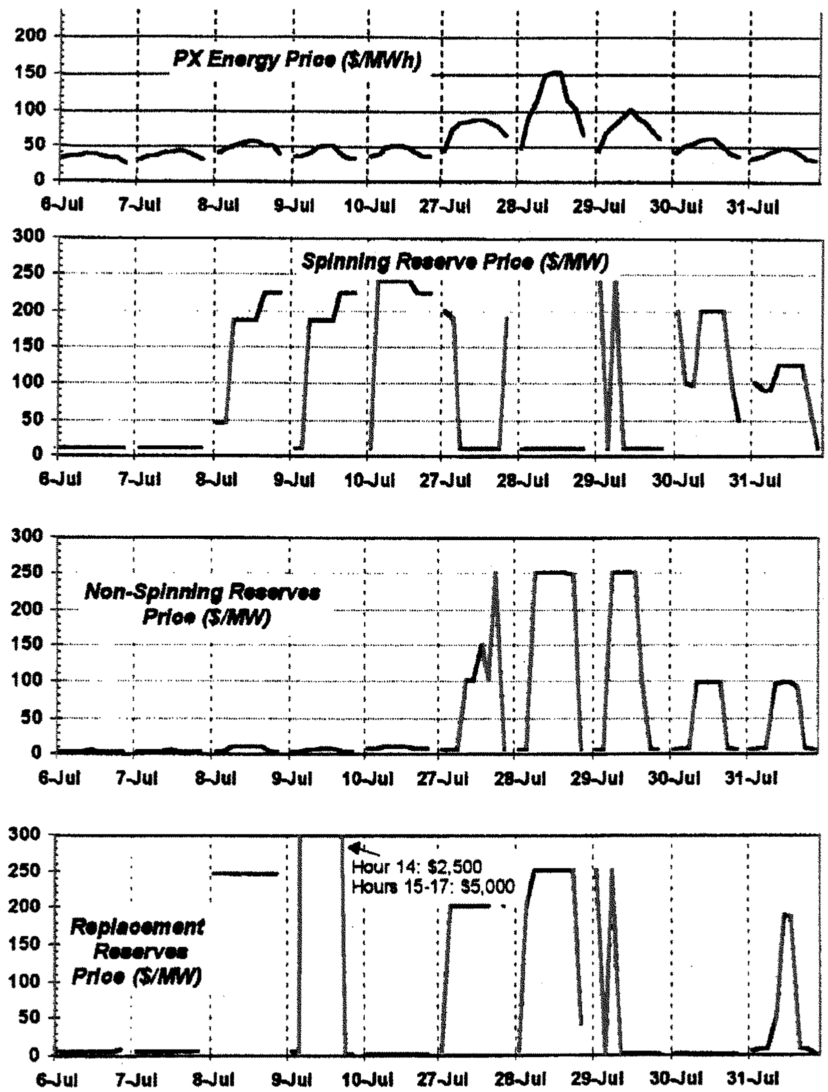


Figure 5 Energy and reserve Prices, selected days, hours 12-20

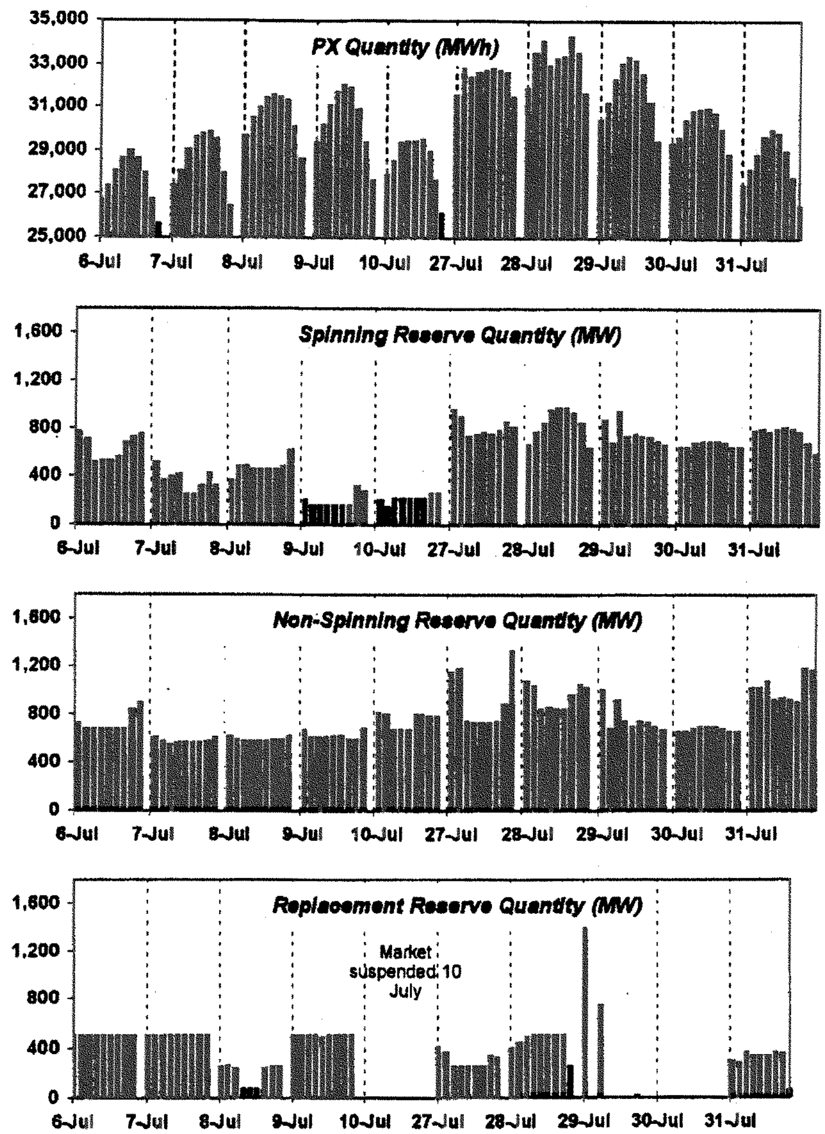


Figure 6 Energy and reserve Quantities, selected days, hours 12-20

One hypothesis about prices in these markets is that jumps in the Ancillary Services market prices are due to increases in capacity being used to serve the PX markets, leaving little capacity for Ancillary Services..[5] During the second week we examined, the $250/MW caps were binding in many hours. We do not have access to the firms' supply curves in the Ancillary Services markets, but our examination of the data on the PX energy markets does not suggest that the $250/MW caps were hit because of any widespread withdrawal of capacity from the Ancillary Services markets in an effort to provide more to the PX market.

Our examination of individual participants' sales in the PX and ISO markets reveals that some of them adjust their 9:30 a.m. bids in the Ancillary Services markets based on what they sold in the 7:15 a.m. day-ahead market. This is an attempt to make sure that capacity not selected in the day-ahead auction does not sit idle. To the extent this occurs, it helps equilibrate prices in the different markets. In principle such behavior does create a tradeoff between the two markets; more sold in one makes less available to the other. However the effect, if it exists, is weak.

We intend to study this issue further as more data become available. Prices in Ancillary Services and in energy markets have risen recently, and there is no reason to believe that the late-July Ancillary Services prices are stable or representative of their long-term behavior.

Comparing Prices: Reserves as Options

Another way to compare the various markets is to examine the profit-making opportunities in each one. If participants are rational, can sell capacity in any market, and have low transactions costs, we would expect prices to equilibrate across markets. More precisely, in equilibrium the expected profits from allocating the last MW of capacity to all markets should be equal. Participants should move capacity from one market to another until this condition holds; until then there would be opportunities to profit from arbitrage across the markets. Casual observation of Figure 5 suggests that prices are far from this equilibrium. Although energy prices seem to follow a regular pattern, Ancillary Services prices change by an order of magnitude from each other, from day to day, and even from hour to hour.

Spinning, non-spinning and replacement reserves are all theoretically call options that the ISO is purchasing. They give the ISO the right to buy energy on a few minutes notice, if it is needed to respond to a contingency. The payments made by the ISO for reserves are per MW of capacity, and are the cost of buying the options. When these reserves are called upon by the ISO, there is also an energy payment per MWh, at the real-time price.[6]

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[5] Recall that Ancillary Services bids are made after day-ahead energy bids have been resolved. Therefore, the energy sales matter more than the energy market bids.

[6] Suppliers are required to include an energy bid with each capacity bid they submit in the reserves markets, but the energy payments they receive if they are called to provide energy are based on the ISO's real-time imbalance price. They are only called if the real-time price is at or higher than their energy bid. This means that the actual "strike" price is equal to or higher than the energy price submitted by the provider.

When, for example, the price of reserves is at $250/MW, this option character of reserves has two consequences. First, the underlying commodity (energy) has consistently been cheaper than the call option, thereby in principle creating an arbitrage opportunity. Second, when deciding how much to offer in each market, participants will make more profit by selling reserves at $250 per MW than by selling energy, even if the energy price reached $250 per MWh. The value of selling a MW as reserves is the expected reserve price plus the expected value of real time price minus marginal running cost. For example, if the reserves price is $200/MW and there is a 40% chance of being called to deliver at a $100/MWh expected Real Time price, the expected revenue is the same as selling in the energy market at $240/MWh. The reserve contract gives about the same profit as an energy price of $258 (if the marginal generating cost is $30/MWh).

The maximum price in the PX day-ahead energy market has been about $160/MWh while Ancillary Services prices have often reached the ISO cap of $250/MW. The price of reserves has exceeded the energy price in many peak hours. Table 9 shows the percentage of hours that the price for each reserve service was higher than the PX day-ahead energy price in early August. Most of the weekday afternoons had such relative prices. The reserve prices averaged close to $250/MW, because they were usually hitting the ISO's price cap. During such hours, in principle the ISO could have purchased energy and "thrown it away" more cheaply than buying the Ancillary Service.

Table 9 also shows the average day-ahead reserves price (option cost) and the real-time ISO energy price (exercise price for the option) during these high-priced hours. To calculate the total payment made to a Supplier who is called upon for reserves, one has to add the cost of the option (capacity payment) to the cost of energy when it is called during the affected hours. For example the first column shows the relevant prices for spinning reserves.

Table 9 Comparison of Revenues from 1 MW in PX and Reserve Markets

August 1 - 12, 1998	Spinning Reserve	Non-spinning Reserve	Replace-ment Reserve
Percentage of Hours that Reserve Price Exceeded PX Price	28%	20%	23%
Average PX Price During Such Hours ($/MWh)	63	90	91
Average Reserve Price During Such Hours ($/MW)	238	249	238
Average Real-Time Price During Such Hours ($/MWh)	72	108	111
Payment Above PX if Called for Capacity Reserve Only ($/MW)	175	159	147
Payment Above PX When Also Called for Energy for full Hour ($/MWh)	247	266	258

As shown in Table 9, the average payment to spinning reserve suppliers in these hours was $310/MWh ($238 + $72). The PX average energy price during the same hours was only $63/MWh. Thus, suppliers of spinning reserve energy received an average payment that was $247/MWh above the average PX price ($310 - $63). Even suppliers who were not called upon to provide energy received payments that were $175/MW above the average PX price. In a smoothly functioning group of markets, suppliers should have recognized that they could make significantly greater profits providing spinning reserves compared to bidding in the PX market during these on-peak hours.

Arbitrage should have eliminated the differential profit opportunities. It is apparent that the markets for Ancillary Services are not in equilibrium with the energy market. Perhaps because there are too few players in the Ancillary Services markets, the paradoxical price inversion persists.

If the cost of buying reserve services is higher than the cost of energy itself the same hour, the ISO would be better off buying energy in the PX day-ahead market to meet its reserve requirements. The ISO could even sell such energy to outside control areas at zero prices on the condition that it could be called back to meet ISO's reliability requirements -- in essence exploiting the arbitrage opportunity between the option and the commodity. This might cause PX prices to increase, but as reserve prices dropped to equilibrium with the PX market, capacity would shift toward the PX market, thereby compensating for the ISO's purchases in the market. An entrepreneurial firm could also take advantage of this arbitrage strategy and keep the profits itself.

VI. Concluding Observations

Based on the information gathered and the study undertaken to date, the Committee has a number of concluding observations to offer. Before we present them, however, it is important to emphasize the Committee's strong belief that competitive and efficient markets can set prices and determine quantities for electricity in California. Although market experience to date indicates the desirability of adjusting some of the current structures and procedures, this does not weaken our belief that properly designed and functioning markets can do the job. The main goal should be to make long-term changes that will remedy the current deficiencies. But we recognize that the market effects of some defects may be so severe that temporary interventions are required. It is important, however, to take all steps possible to ensure that short-term actions do not impede long-term effectiveness of the markets.

We turn now to more specific observations about the PX energy markets and their relation to the ISO's ancillary-services markets. These remarks are based on our time-limited study concentrating on the performance of the PX market, the behaviors of key participants in that market, and the interactions between the PX market and the ISO's markets for ancillary services.

First, the PX Day-Ahead market has functioned smoothly since its inception in April. The Hour-Ahead market is too new to analyze, though we are concerned about how slowly activity is developing there. The Day-Ahead market is large with a number of participants. It has, however, seen some very high prices during July and August. Our review of the data gives us some cause for concern about the ability of a small number of participants to affect prices at times of high demand. This is an area that we have been watching and will continue to follow carefully, particularly since high prices on the PX market have a larger impact on the overall cost of electricity in California than do comparable Ancillary Services prices.

Second, while high prices have been of concern in the PX Day-Ahead market, they have been of even more concern in some of the ISO's Ancillary Services markets. Indeed, the level of those prices gave rise to the ISO's request to the FERC, which in turn led the FERC to call for this report. The very high Ancillary Services prices reflect an insufficiency of supply offers relative to demand at particular times, which can then bestow significant market power on the generators that provide ancillary services. The principal solution to this problem is the entry of new units and new participants into the ancillary services markets. That is, insofar as the supply-side problem is structural in character, it requires a structural solution.

Steps must be taken to encourage entry in the short and long run. Removing restrictions on who is allowed to participate in the various markets, as the ISO has recently done with out-of-control-area generators, is one way to enhance entry in the near term. To the extent that some loads can be reduced as fast as generators can ramp, encouraging demand-side bidding for ancillary services is another means to increase supply, perhaps even in the short term. Furthermore, Regulatory Must-Run contracts should be considered in the overall context of the provision of system reserves. The incentives in those contracts should be structured so that owners of such units are not inefficiently induced to withdraw from the energy market or the ancillary services markets.

While supply-side development is essential to the long-term success of the Ancillary Services markets, it is also important that the ISO's demand for Ancillary Services be rational and responsive to economic incentives, while staying within the bounds of regulatory constraints and reliability objectives. The overall level and composition of ancillary services bought by the ISO should be determined in an integrated and economic way. System security constraints should be met by procuring the least-cost mix of the several ancillary services. For example, the ISO should be able to substitute among types of reserves when a more flexible type is available at a lower price. When energy prices are below reserves prices, energy too should be considered in the mix. Furthermore when some Ancillary Services' prices are very high, the ISO should continue to make the judgment to purchase less of them, as it apparently did for Replacement Reserves when the price would have reached $10,000 per MW.

Third, the current market problems are sufficiently severe that they call for short-term intervention in the market, such as price caps. This will reduce deleterious market outcomes and provide "breathing room" for the development and introduction of long-term improvements. If generators in the Ancillary Services markets have and exercise considerable market power in the short run it will induce inefficient behavior that will spill over to the energy market. Since the Day-ahead energy market clears before Ancillary Services bids are submitted, a firm wishing to bid in the Ancillary Services markets will have to offer less capacity in the Day-ahead market. Although most of the time such a bid might earn little, the prospect of a lottery-type win for a few hours in one or another of the reserve markets could suffice to make the strategy worthwhile. While we expect that prices would eventually equilibrate on average in the different markets, they would do so only with considerable distortion among the various markets. Unit commitments and other decisions would be distorted by the inaccurate price signals. Furthermore, allowing the exercise of unbridled market power could lead to substantial wealth transfers and cause political pressure for re-regulation, thereby undermining the possibility of having successful markets in the long term. In short, the Committee is persuaded of the need for short-term market interventions, perhaps in the form of price caps, to cope with serious, market-impairing structural problems.

It is important, however, to minimize the long-term effects of any short-term intervention that is made to cope with such market power. For example, the introduction of price caps may impede future entry if potential entrants worry about the possible imposition of additional caps. The extenuating circumstances justifying the intervention should be made clear and distinguished from the ordinary course of market events in a well-functioning market, and the temporary character of the intervention should be emphasized. Maintaining the credibility of the market and its institutions is essential.

The price cap level, if that is the intervention chosen, must be carefully selected. The price cap needs to be set at a level that will provide the entry that we seek as the long-term solution to the structural problem. Given the linkages among markets, a price cap imposed on one ancillary service market will have an effect on the others and on the several energy markets as well. A cap that is too high or too low may distort behavior in one of those complementary markets. In particular, in setting the price cap, and comparing it with energy prices, it is important to bear in mind that Ancillary Services give an option to buy energy at the real-time price.

Finally, although the Committee believes that some short-term market interventions, perhaps in the form of priçe caps, are appropriate, it believes that low, participant-specific price caps consisting of cost-based rates for Ancillary Services are inappropriate. The cost-based -rate rules that are still in effect for some participants set the prices for those suppliers well below the prices that generally clear the energy markets during times of high demand. Thus, if those cost-based rates are imposed on a participant, that agent has an incentive to not offer capacity to Ancillary Services and instead to sell all its capacity in one of the energy markets. Although this restrains prices in the energy markets, it does so at the cost of distorting the signals about the relative value of ancillary services and energy. With cost-based caps imposed on some participants, inefficient quantities are offered to the Ancillary Services markets. This in turn could lead the ISO to resort to mandatory orders to generators to provide such services and further distortions of participant behavior and of prices. We recommend removing the cost-based rate caps that remain in effect.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Committee on Governmental Affairs
EXHIBIT #A-53

San Diego Gas & Electric Company

Complainant,

v. Docket No. EL00-95-000

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

Respondents.

Investigation of Practices of the California
Independent System Operator and the
California Power Exchange Docket No. EL00-98-000

Public Meeting in San Diego, California Docket No. EL00-107-000

California Power Exchange Corporation Docket No. ER00-3461-000

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

MARKET ORDER PROPOSING REMEDIES FOR CALIFORNIA
WHOLESALE ELECTRIC S

(Issued November 1, 2000)

TABLE OF CONTENTS

Introduction and Summary

On August 23, 2000, the Commission issued an order in Docket Nos. EL00-95-000 and EL00-98-000, initiating hearing proceedings under section 206 of the Federal Power Act (FPA) to address matters affecting bulk power markets and wholesale energy prices in California.[1] The Commission held the hearing in abeyance, however, pending the results of a separate staff fact-finding investigation, ordered by the Commission on July 26, 2000, of the conditions in electric bulk power markets (including volatile price fluctuations) in various regions of the country.[2] The Commission has now had the opportunity to analyze the staff investigation report (Staff Report) as it pertains to California and the Western region, and has placed that report in the record of this proceeding. Based on that report, as well as other submissions in these dockets[3] and the Commission's experience in dealing with evolving California market issues in over 85 Commission orders since the time the restructured California markets began operation in 1998, and based on the seriousness of market dysfunctions and recent pricing abnormalities in California, in this order the Commission is proposing specific remedies to address dysfunctions in California's wholesale bulk power markets and to ensure just and reasonable wholesale power rates by public utility sellers in California.

The Commission finds in this order that the electric market structure and market rules for wholesale sales of electric energy in California are seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand in California, have caused, and continue to have the potential to cause, unjust and unreasonable rates for short-term energy (Day-Ahead, Day-of, Ancillary Services and real-time energy sales) under certain conditions. While this record does not support findings of specific exercises of market power, and while we are not able to reach definite conclusions about the actions of individual sellers, there is clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates under the FPA. Under such conditions, the Commission is obligated under FPA section 206 to take action to establish market rules, regulations and practices that will ensure just and reasonable rates in the future.[4] Accordingly, we herein propose fundamental

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

[2]See Order Directing Staff Investigation, 92 FERC ¶ 61,160 (2000) (July 26, 2000 Order).

[3]In addition to the Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities - - Part 1, November 1, 2000 (Staff Report), the Commission has placed in the record the transcript of the Commission's September 12, 2000 public meeting in San Diego, California, written submissions in response to that public conference, and all reports prepared by the ISO and PX and their market surveillance committees.

[4]Under section 206(a) of the FPA, if the Commission finds, after hearing, that any rate, charge, (continued...)

modifications to the wholesale market structure and rules currently in place in California; we also propose price mitigation measures to ensure that wholesale rates remain just and reasonable during the period it will take to effectuate the market structure and market rule changes being proposed. Rates charged by public utilities for sales into the ISO's markets and into the PX's day-ahead and hour-ahead markets will remain subject to the refund conditions set forth in the August 23 order, as discussed more fully below.[5]

In developing the proposed remedies in this order, the Commission's goal has been to balance, on the one hand, holding overall rates to levels that approximate competitive market levels for the benefit of consumers, with, on the other hand, inducing sufficient investment in capacity to ensure adequate service for the benefit of consumers. We believe that a well functioning competitive wholesale power market in California, which includes a well functioning regional transmission grid, is a fundamental part of the solution to the supply problems and price volatility in California. The interstate, wholesale nature of electric markets in California and adjoining states makes it incumbent that we take whatever steps we can to make markets in the region work for the ultimate benefit of consumers – assuring a reliable supply of energy at the lowest reasonable rate.

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

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[4](...continued)
or classification for jurisdictional services, or any rule, regulation, practice, or contract affecting such rate, charge or classification "is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order."

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

previously made by the State in its initial restructuring legislation and orders. Unless we take these steps, we believe we will be abdicating our responsibility under the Federal Power Act to ensure just and reasonable rates and service by public utility sellers of wholesale energy in California.

The immediate remedies proposed in this order include:

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

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

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

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

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

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

The Commission has concluded that the hearing we ordered on August 23 does not need to be a trial-type hearing. Rather, the issues raised in this proceeding can be resolved based on written comments and evidence and oral presentation directly to the Commission. The Commission will permit all interested persons that have not already intervened in these dockets to intervene, and allow all interested persons to file comments on the proposed remedies and any additional information or evidence, by November 22, 2000. We also will hold a public conference on November 9, 2000, which will provide interested persons the opportunity to discuss the proposed remedies before the Commission.

Background

A. California Restructuring

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

PG&E, SoCal Edison, and SDG&E submitted filings to this Commission in April 1996 seeking approval for those aspects of the restructuring subject to FERC's jurisdiction, namely, the conveyance

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

[7] See California Commission Decision D.95-12-063 (Dec. 20, 1995), modified by D.96-01-009 (Jan. 10, 1996) and D.96-03-022, 166 P.U.R. 4th 1 (California Commission Restructuring Decision).

[8] AB 1890, signed by Governor Wilson on September 23, 1996, California Statutes 1996, Chapter 854 (Restructuring Legislation or AB 1890).

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

of operational control of transmission facilities to the ISO, [10] the authority to sell energy at market-based rates through the PX, and approval of the overall framework for establishment of the ISO and PX, and for the jurisdictional split between the transmission and local distribution facilities of the utilities. In a series of orders issued that Fall, the Commission largely accepted the filings, and provided a preliminary assessment of the adequacy of the utilities' market power analyses. [11]

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

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

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

[11]See Pacific Gas and Electric Co., et al., 77 FERC ¶ 61,077 (1996) (PG&E I); Pacific Gas and Electric Co., et al., 77 FERC ¶ 61,204 (1996) (PG&E II); Pacific Gas and Electric Co., et al., 77 FERC ¶ 61,265 (1996) (PG&E III). One area of particular concern for the Commission was the scope of the Oversight Board's functions. Specifically, the Commission noted that it could not "accept a permanent role for the Oversight Board in the governance or operation of the ISO, or appellate review of ISO Board decisions, because these matters are within our exclusive jurisdiction." See PG&E II at 61,818.

[12]Pacific Gas and Electric Co. et al., 81 FERC ¶ 61,122 (1997) (October 30, 1997 Order).

[13]Among the four jurisdictional ISOs that are in operation, the Commission has devoted, by far, the most resources to the California ISO, and most of the attention required by the California ISO reflected the difficulties in implementing the requirements of AB 1890 and the impact of those

(continued...)

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

The ISO sought price caps as a solution for the volatility and thinness in its Ancillary Services markets. In the July 17, 1998 Order, we authorized the ISO to reject bids in excess of whatever price levels it believed were appropriate for the ancillary services it procures. On rehearing, we explained that, as the procurer of ancillary services , the ISO had the discretion to reject excessive bids. We also stated that a purchase price cap is not an ideal approach to operating a market and that we did not expect the cap to remain in place on a long-term basis.[17] In order to make the Imbalance Energy market similarly situated to the Ancillary Services markets, we later authorized the ISO to adopt a purchase price cap for its Imbalance Energy market at whatever level it deemed necessary and appropriate.[18]

In our order approving the ISO's Ancillary Services market redesign proposal, we allowed the ISO to retain its authority to specify purchase price caps for Ancillary Services and Imbalance Energy until November 15, 1999.[19] The ISO had proposed to raise and eventually eliminate existing price caps on Ancillary Services and Imbalance Energy upon the implementation of several redesign

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[13](...continued)
requirements on transmission grid operations and market performance.

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

[15]October 28, 1998 Order, 85 FERC at 61,462.

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

[17]85 FERC at 61,463.

[18]California Independent System Operator Corporation, 86 FERC ¶ 61,059 (1999).

[19]87 FERC at 61,817-19.

elements, but in the interim, it planned to maintain the current $250 price caps. The ISO had also proposed a safety net in which it would continue to monitor the markets, and if it identified market failures or supply insufficiencies, it would lower price caps in the affected markets. We directed the ISO to eliminate the price caps by November 15, 1999, with the caveat that the ISO could file for an extension of its price cap authority if its experience with the market reforms over the summer indicated serious market design flaws still existed.

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

B. Events of Summer 2000

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

High temperatures and generation outages led the ISO to declare system emergencies 39 times between May and August. PG&E had to effect rolling black-outs in San Francisco area on June 14. Notably high prices were also experienced at trading hubs throughout the Western Interconnection. During this summer period, costs of electricity inputs began to increase, particularly gas costs at the California border which rose from $2/MMBtu in the spring to about $6/MMBtu this summer. At the

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[20] California Independent System Operator Corporation, 89 FERC ¶ 61,169 (1999), reh'g pending.

[21] Price Movements in California Electricity Markets: Analysis of May - July 2000 Price Activity, PX Compliance Unit, September 29, 2000 at 10.

[22] Report of California Energy Market Issues and Performance: May - June 2000, ISO Department of Market Analysis, August 10, 2000 at 13.

same time, existing gas fired units[23] were operated at unprecedented levels, driving up the price of NOx emission allowances from around $6/lb to over $40/lb at the end of August.[24]

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

These events have created an environment of distress in the State. Probes have been initiated by the California Commission, the Oversight Board, and California's Attorney General, in addition to the investigation by this Commission discussed below. In August, the California Commission put in place a temporary retail rate cap for certain small customers of SDG&E, limiting the amount that they must pay per month. Subsequently, the California legislature enacted AB 265, a retroactive retail cap which expands on the California Commission's action. The legislation limits San Diego residential customers' rates to 6.5 cents per kWh, and requires the California Commission to investigate the purchasing practices of SDG&E. Both retail rate caps defer payment of the total amount due to the utility, requiring customers to pay the balance of costs paid into the wholesale market with interest in the year 2003.

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

The ISO and PX and the ISO's Market Surveillance Committee (MSC) analyzed the pricing anomalies experienced during the summer and came to similar conclusions. A preliminary report prepared by the PX dated September 29, 2000, found that price spikes were caused by flawed market structures and an insufficient supply of power, rather than gaming by market participants. Although

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[23]Natural gas comprises about 55 percent of California's fuel mix.

[24]Staff Report at 3-21.

[25]The two utilities have reported about $4.6 billion in unrecovered wholesale costs of which about $2 billion reflects sales of electricity sold from generation which they still own.

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

[27]See Electric Utility Week, Oct. 9, 2000, pp. 5-6.

market conditions created the potential for abuses of market power, the PX Report indicated that no one group of participants was setting prices. The ISO, similarly, reported that during certain operating conditions, suppliers can have significant market power, although the underlying causes of high prices were structural and operational in nature.

C. Commission Actions in Response

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

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

On August 2, 2000, SDG&E filed a complaint in Docket No. EL00-95-000 against all sellers of energy and ancillary services into the ISO and PX markets requested, among other things, that the Commission impose a $250 price cap. The August 23 Order denied SDG&E's request because the company had not provided sufficient evidence to support an immediate seller's price cap. [30] However, the Commission instituted formal hearing proceedings under section 206 of the Federal Power Act to investigate the justness and reasonableness of the rates of public utility sellers in the California ISO and PX markets, and also to investigate whether the tariffs, contracts, institutional structures and bylaws of the ISO and PX are adversely affecting the efficient operation of competitive wholesale power markets in California and need to be modified.

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[28] See infra, note 2.

[29] Morgan Stanley Capital Group Inc. v. California Independent System Operator Corporation, 92 FERC ¶ 61,112 (2000) (Morgan Stanley).

[30] 92 FERC at 61,606. (Commissioner Massey dissented on this point.)

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

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

Briefly, the Staff Report identifies three factors that contributed to the high prices experienced in California this summer. First, competitive market forces played a major role in the run-up of prices through significantly increased power production costs combined with increased demand due to unusually high temperatures and a scarcity of available generation resources throughout the West and California in particular.

In addition, the Staff Report concludes that existing market rules along with some flawed retail regulatory policies exacerbated the situation. The Staff Report notes that the requirement placed upon the three IOUs by the California Commission to buy and sell all their energy needs through the PX, coupled with the California Commission's restrictions on their ability to forward contract, exposed the three IOUs to the volatility of the spot market without the ability to mitigate this summer's price volatility. The Staff Report also notes that a lack of demand responsiveness on the part of retail load allows prices to rise well above competitive levels when demand is high and supplies are scarce. Finally, the Staff Report finds that the ISO's policies relating to replacement reserves increased the amount of demand and supply that appears in the ISO's real-time market (underscheduling in the PX), which results in operational and reliability problems for the ISO and increased costs. The Staff Report recommends that the Commission eliminate these flawed market rules.

Lastly, the Staff Report notes that there is evidence suggesting that sellers had the potential to exercise market power (where market power is defined as prices above short-run marginal cost) this summer; however, the data analyzed in the Staff Report and the limited time available were not sufficient to make determinations regarding the exercise of market power by individual sellers. [31] One

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

of the Staff Report's proposed changes to the market rules would eliminate the single price auction rule.[32]

D. Docket No. ER00-3461-000

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

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

The California Commission, the Oversight Board, PG&E, and SoCal Edison support the filing and request its approval as an interim measure until additional steps are taken to restore prices to just and reasonable levels. Other intervenors argue that the filing should be rejected because: (1) the PX has provided virtually no justification for its proposed price cap; (2) the proposal would further intrude into the competitive energy markets and should be deferred; and (3) the PX's proposal is inconsistent with the Commission's findings in Morgan Stanley. Power marketers also argue that price caps are unnecessary and harmful to the development of a competitive electric market by jeopardizing investment in generation and creating an atmosphere of extreme uncertainty.

E. Docket No. ER00-3673-000

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

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

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

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

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

Interventions and Other Pleadings

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

[33] August 23 Order at 61,606.

Vernon, California, (Vernon); San Diego; the California Large Energy Consumers Association (CLECA); and Puget Sound Energy, Inc. (Puget Sound).

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

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

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

Procedural Matters

In view of the early stage of the consolidated hearing proceedings and the absence of any undue prejudice or delay, we find good cause to grant the untimely, unopposed motions to intervene of CAC/EPUC, Southern Cities, San Diego, Vernon, CLECA, and Puget Sound. Appendix C lists all parties to this proceeding. In addition, the Commission will permit all interested persons that have not already intervened in these dockets to intervene and file comments by November 22, 2000.

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

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

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

Discussion

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

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

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

The events of this summer provide dramatic evidence of the interstate nature of electric systems and markets in the Western Interconnection. California is not an electrical island. Operationally, the transmission facilities currently controlled by the ISO are part of the much larger Western Interconnection.[35] The reliability of California's electric system depends on access to generating resources located throughout the Western Interconnection.[36] Decades ago, western utilities made large investments in high voltage interstate transmission lines to support the market efficiencies resulting from seasonal diversities between the northern and southern markets. Over time, California utilities have increasingly relied on imports from generation located in neighboring states to meet their load requirements and have constructed significant transmission interties to import electricity for California consumers.[37] This summer, exports from California to others increased. Therefore, the operation of the California electricity market can affect prices throughout the entire Western Interconnection. The Staff Report demonstrates that during the summer of 2000 correlations between PX prices and Western market bilateral prices were quite strong.[38]

We make these observations to provide some context for the actions we are proposing in this order. We commend and continue to support California's efforts at restructuring its electricity markets to try and bring lower prices to consumers in California. Although California's restructuring initiatives directly implicated matters subject to our jurisdiction, in order after order, we have deferred wherever possible to the restructuring decisions made by the State. We have devoted unprecedented resources to try and make the California initiative a success. Ultimately, however, the Commission must ensure that wholesale market rules and institutions -- even those created by state action -- result in just and reasonable wholesale rates for electricity. This summer's events in California and our subsequent investigation have convinced us that we must take decisive action under section 206 of the Federal

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

[36] California's import capability is approximately 8,000 MW.

[37] Two of the first trading hubs for wholesale electricity futures were founded at the California/Oregon Border (COB) and at Palo Verde, in Arizona, because of the significant amounts of interstate market activity that occurs at these points.

[38] See Staff Report at 1-3, 3-15 - 3-17.

Power Act to remedy fundamental problems that have been identified in the California market design. The California experience has highlighted the dangers of hard-wiring a market design that is inflexible and cannot adapt to needed changes.

It is important to get the fundamentals right and to devise a roadmap that takes into account the needs of the market and the regional implications of electricity trade. In many ways, this is the approach that Order No. 2000 has taken with regard to the formation of Regional Transmission Organizations. But Order No. 2000 avoided being overly prescriptive and even went so far as to adopt a requirement of open architecture to ensure that RTOs could adapt and evolve to meet the changing needs of the marketplace. Market rules and institutions need to be flexible so that they support the natural evolution of the marketplace. In California, we are confronted with a situation where market participants have to work around overly prescriptive market institutions and requirements which have become an impediment to the efficient operation of the marketplace and which have harmed consumers. The existing market has not lowered prices to consumers this summer nor stimulated needed investment in new generation and transmission facilities.

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

A. Overview

One of the primary Congressional goals in enacting Part II of the Federal Power Act was to protect electric ratepayers from exercises of market power. Ratepayer interests generally centered on ensuring that rates were not excessive or unduly discriminatory. The need to ensure an adequate supply of generation usually was met through requirements imposed by states on franchise utilities to build or buy adequate power resources to meet demand consistently. Today, however, in states such as California, the adequacy of local power resources depends, not just on state requirements, but also on whether market prices are sufficient to elicit adequate supplies, through construction or otherwise. In

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

other words, when supply is driven by market price instead of regulatory requirements, ratepayer interests may no longer depend solely on whether current prices are deemed too high, but also on whether prices are too low to elicit new supplies over time.

As indicated by the Staff Report and by reports prepared by California State agencies and others, this summer's wholesale markets exhibited certain market fundamentals that would be expected to cause prices to rise. Input costs increased as the cost of fuel, emission credits and O&M expenses increased.[40] Sustained demand increased, requiring increased reliance on generating resources that would have been more expensive to operate even if input prices had not increased.[41] Conditions in the Northwest decreased amounts of hydropower supply usually available to the market which, combined with a failure to bring new generation into service over the last decade, resulted in a true scarcity of generation.[42] In circumstances like this, prices are expected to rise - - and indeed they must rise to induce the investment in new capacity that is needed to serve customers adequately.

The issue raised in this proceeding is whether dysfunctional market rules or the exercise of market power allows prices to rise above just and reasonable levels. We conclude that certain market rules do interfere with the functioning of the market and, taken together, may permit sellers to exercise market power. Accordingly, these market rules must be revised. Many of the market dysfunctions in California and the exposure of California consumers to high prices can be traced directly to an over reliance on spot markets. Industries that are either capital intensive or that have a lack of demand response do not rely solely on spot markets where volatility is to be expected. Because the price risks inherent in spot markets are too great for both suppliers and consumers, these market sectors will prefer to manage their risk profiles through forward contracts. However, in California, certain market rules imposed by AB 1890 and its implementation by the California Commission (e.g., mandatory buy-sell through the PX) prevented the IOUs from engaging in forward contracts to any significant degree. And other retail suppliers who would have been free to implement appropriate risk management strategies could not be induced to participate in California's market because the low retail rate, frozen at 10 percent below historical levels, thwarted competitive opportunities for new participants to enter the market.[43] Even so, until the market was stressed this summer by extreme events, pricing volatility was isolated and short-lived and wholesale prices were so low that stranded costs were paid off more

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[40] Staff Report at 3-20 - 3-22.

[41] Id. at 5-2, 5-3, and 5-6.

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

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

quickly than expected. The significant failings of this market design became apparent only as peak demand outstripped supply.

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

A second critical issue we address is the ability of the ISO and PX to operate and implement wholesale markets and the ability of the ISO to operate a transmission system reliably and efficiently under the governance of its stakeholder board of directors. The functioning of wholesale markets and the reliability and efficiency of the interstate transmission grid cannot be compromised by a decision-making process that is overly complex, mired in controversy, or prone to excessive influence by special interest groups. Boards, whether comprised of stakeholders or non-stakeholders, must be able to respond decisively to conditions necessary to maintain system integrity and operation. Most importantly, because the markets operated by the PX and the ISO are interstate markets and the transmission system operated by the ISO is part of an interstate transmission grid, the ISO's decision-making process must be responsive to the operations and the welfare of the regional marketplace, and not be restricted to the concerns of one geographic location or one segment of the market. Based on past performance, the ISO and PX boards no longer meet these standards. For these reasons, we propose to disband the stakeholder boards and direct the establishment of independent boards.

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

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

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

B. Proposed Immediate Measures

1. Requirement to Sell Into and Buy From the PX

The California Commission Restructuring Decision required that the three IOUs sell all of their generation into and purchase all of the energy requirement for their retail load from the PX.[45] In so doing, the California Commission established a mechanism to ensure that the IOUs could not withhold generation from the market prior to the completion of divestiture and to value in a systematic way the above market generation assets which the IOUs had not divested. Sales at frozen retail rates in conjunction with purchases at lower market prices created a revenue surplus from which to write off stranded costs and to transition to a regime of fully competitive prices. The requirement, in fact, was to end on the earlier of March 31, 2002, or the date when the IOUs had written off all of their stranded costs.[46]

During the first three years of operation, a confluence of favorable temperatures and hydro conditions resulted in such low spot market prices that the IOUs were able to write off substantial amounts of stranded costs. Because of these conditions and the valuation of their divested generation assets, the IOUs have either written off or valued virtually all of their stranded costs. However, this past summer's experience and the Staff Report make clear that these favorable market conditions have evaporated. A robust economy with little investment in capacity additions, high temperatures throughout the West and little supply response have now resulted in power costs above the frozen retail, rate levels.[47] The IOUs' reliance on the PX, and, in particular, the California Commission's requirement that they bid the majority (upwards of 80 percent) of their load into the PX's day-ahead

[45] Initially, the PX administered only a Day-Ahead and an hour-ahead (Day-of) spot Market. Later, it added limited forward marketproducts.

[46] Section 368 of AB 1890.

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

and hour-ahead spot markets [48] created substantial short-term cost exposure and price spikes of such a magnitude that market confidence became virtually nonexistent. The details of the Staff Report paint a bleak picture of an over reliance on a spot market in a circumstance of inadequate supply. Moreover, because the IOUs have now divested substantially all of their thermal generation they are substantial purchasers of energy. [49] Therefore, forced sales into the PX by the IOUs to prevent withholding are no longer necessary.

As a result, we conclude that the requirement for the IOUs to sell all of their generation into and buy all of their requirements from the PX, whether in its spot or forward markets, is a significant factor contributing to rates that are unjust and unreasonable, [50] and we propose to declare it null and void effective 60 days from the date of this order. Under this proposal, the IOUs may elect to be their own Scheduling Coordinator rather than maintaining the current structure where the PX is the Scheduling Coordinator for the three IOUs. Without this buy/sell restriction on wholesale trade, the IOUs are free to pursue a portfolio of long- and short-term resources and access whatever wholesale markets are suited to meeting the 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. [51] As an independent exchange, the PX will be free to design and offer the services needed by market participants.

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

2. Underscheduling of Load and Resources

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[48]While the IOUs have recently been authorized by the California Commission to use either the PX's forward markets or the bilateral market, the overall restrictions on the total amount of forward purchases remain.

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

[50]The Staff Report reached a similar conclusion. Staff Report at 5-9 and 5-11.

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

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

The record indicates that there is a chronic pattern of underscheduling [53] load and generation in the PX's Day-Ahead and Day-of market. [54] As a result, large amounts of load are not being scheduled with the ISO and the ISO is often in the position of procuring a substantial amount of energy to meet these needs in real time. In some hours the ISO has been faced with acquiring upwards of 6,000 MW of system energy needs, in real time. [55] The ISO has reported that underscheduling was 50 percent higher this summer than the previous two summers. The cost of out-of-market purchases needed to balance load at the last minute rose to $100 million this summer compared to about $1 million last summer. Underscheduling has caused the ISO's operating personnel to call upon energy from capacity that had been procured for Operating Reserves. As a result, this reserve capacity has been diverted from its intended purpose - protecting against the loss of a component of the system. In addition, the underscheduling resulted in 39 stage-one and stage-two emergencies between June and August 2000, and 13,500 MWhs of load was curtailed. [56] The combination of these problems places even more pressure on system operators.

As a practical matter, the ISO is often not simply providing the real-time services needed to operate a transmission system and balance the market, but is actually forced to operate an energy market and to become a market participant in order to make last minute purchases as a supplier of last resort. The PX Day-Ahead and Day-of Markets were designed as spot market exchanges; the ISO's real time market was not intended to provide this function. Underscheduling puts system reliability at risk and creates a stronger sellers' market and higher prices as real time approaches. In an attempt to

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

[53]Underscheduling occurs when an entity schedules significantly less energy than its expected actual consumption.

[54] Staff Report at 5-14 and 5-16.

[55]See __ FERC at .

[56]August 25, 2000 Memorandum from Mr. Winter to ISO Board of Governors.

address this problem, we directed the ISO in the August 23 Order to use a more forward approach in procuring these energy needs. [57]

As discussed above, the elimination of the buy/sell requirement in the PX will allow for greater discretion for the IOUs to self supply or to procure resources in bilateral or other markets for their energy requirements as well as necessary ancillary services. We believe that the existing underscheduling problem is addressed in part by this revision to the market. We propose to temporarily correct the current situation by limiting the ISO to only the functions needed to reliably operate the transmission system, i.e., provide a balancing service rather than running an energy market. To address this reliability problem and to ensure that loads do not rely excessively on the ISO as the provider of last resort, we propose to establish a penalty charge for deviations in excess of five (5) percent of an entity's hourly load requirements. [58] Loads in excess of this deviation band that are not scheduled in the Day-Ahead or Day-of Markets will be assessed a penalty charge of two times the ISO's real time energy cost for any purchase of balancing energy during the hour. The penalty will not exceed $100/MWh (i.e. the actual imbalance cost plus $100), which approximates the current charge assessed to underscheduled load for replacement reserves. As to the penalty, we have long set disincentive rates for emergency service at twice the standard rate, and we will apply that policy here. [59] As a further incentive to encourage accurate scheduling in the Day-Ahead or Day-of Markets, we propose to direct the ISO to disburse at the end of the billing period all penalty revenues (revenues above costs) pro rata to the loads that scheduled accurately and that did not exceed the 5 percent deviation band for that hour. In addition, later in this order we propose to remove one of the financial incentives for sellers to favor the real-time market by providing that suppliers in the real-time market receive either a capacity payment for replacement reserves or energy payments, but not both. We also describe later in this order auction modifications that should eliminate the need for the ISO to go out of market to procure energy needed for the balancing market. As a result, loads when properly scheduled will be better able to access required supply. We believe that this more orderly process for system operations in conjunction with the ISO's use of forward contracts will better enable the ISO to reliably operate the transmission system.

Underscheduling is a symptom of many of the other market flaws. [60] Because our order addresses many of these problems we expect the underscheduling problem to subside. The ISO should consider other market design changes that would address underscheduling.

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[57] 92 FERC at 61,608.

[58] We propose 5 percent because this is the maximum amount that the ISO intended to balance in the real-time market for operating the transmission system.

[59] See, e.g., Indiana Michigan Power Company, et al., 44 FERC ¶ 61,313 at 62,078 (1988).

[60] See also Section C3. Balanced Schedules below.

3. Governance of the PX and ISO

The Commission conditionally authorized the establishment of the ISO and PX in November 1996.[61] In that order, the Commission noted the accelerated schedule for commencement of operations and committed to dedicate the necessary resources to accomplish that schedule. The Commission also expressed its intent to give great weight to the views expressed in the California Restructuring Legislation. The Commission's deference is most apparent with respect to the governance of the ISO and PX. The parties had proposed that the ISO and PX would be governed by boards composed of individuals residing in California who were chosen to represent various stakeholder classes (i.e., transmission owners, municipal entities, sellers, end-users, etc.), with each class having a specified number of voting representatives. The Governing Boards would be responsible for broad operating criteria, rather than daily decisions and functions, and members were to vote individually, not as a class. As initially proposed, the Oversight Board was intended to perform two primary functions: (1) establish nominating/qualification procedures for the ISO and PX Governing Boards, determine the composition of Board representation, and select Board members both initially (Start-Up Function) and in the future; and (2) serve as a permanent appeal board for reviewing ISO Governing Board decisions.

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

[61] PG&E II.

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

[63] 77 FERC at 61,816-17; 81 FERC at 61,453.

were – and remain – within our exclusive jurisdiction. [64] Consequently, the Commission stated that the continuing functions of the Oversight Board established by the Restructuring Legislation would conflict with our statutory duties under the Federal Power Act and could not remain a part of the proposal. [65]

The Commission recognized, however, that states have a legitimate oversight role with respect to traditional retail matters such as: protecting the welfare of the state's retail consumers and citizens; protecting the reliability of electric service to California retail consumers; ensuring the adequacy of the generating and transmission resources necessary to achieve designated planning and operating reserve criteria to ensure adequate service to end-use consumers; monitoring whether the California retail electricity market is a well-functioning market and delivers the public benefits for which it was developed; and ensuring that the ISO and PX keep retail consumers adequately informed of matters affecting retail electric consumers. The Commission further stated that this role would not conflict with its jurisdiction and would address state-jurisdictional matters. [66]

The Oversight Board subsequently filed a petition for declaratory order requesting that the Commission declare that a bill pending in the California Senate (SB 96), modifying the Board's duties under the Restructuring Legislation, if enacted, would resolve the Commission's concerns about its role. [67] Rather than giving the Oversight Board confirmation power over all members of the ISO and PX Boards, SB 96 afforded the Oversight Board confirmation rights over a limited number of members representing primarily end-users, and addressed the residency requirement. In addition, the structural composition of the Governing Boards was to be modified as soon as another state were to participate in the ISO and PX. SB 96 provided that California could change the ISO and PX Governing Boards into non-stakeholder boards, subject to filing revised Bylaws with the Commission. SB 96 also limited the function of the Oversight Board as an appeal board to ISO decisions regarding eight distinctly state-retail matters. [68] In the Oversight Board decision, we accepted, as consistent with the FPA, the Oversight Board's limited interim appointment function and limited appellate review rights set forth in SB 96.

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[64] See 77 FERC at 61,818.

[65] 81 FERC at 61,451-53; see also California Power Exchange Corp., et al., 85 FERC ¶ 61,263 (1998).

[66] 85 FERC ¶ 61,264 at 62,068.

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

[68] These state-retail matters included, e.g., state functions assigned to the ISO and PX under state law, matters pertaining to retail electric service or retail sales of electric energy, and open meeting standards and meeting notice requirements.

Events over the past two years increasingly have made clear that the ISO Governing Board has such difficulty reaching decisions on the complex and divisive issues confronting it that it has become ineffective. The Staff Report comments on this deficiency. [69] For example, from this Commission's perspective, ancillary services are a critical part of a competitive market. However, the ISO's redesign of its Ancillary Services markets, which was intended to be a global, comprehensive effort to be implemented within perhaps nine to twelve months, has been approved and implemented in piecemeal fashion over a very long term. Similarly, the ISO's reform of its congestion management program has been embroiled in dissension and postponed beyond a reasonable length of time. [70] Most recently, the ISO's efforts to address this summer's price abnormalities could not be resolved by its Governing Board. The ISO's October 20, 2000 submission in this proceeding was not submitted to the Governing Board for its consideration. A news report quotes the ISO's President and CEO explaining that no consensus regarding market mitigation proposals could be developed "'since everyone had a different concern or a different idea for how to change the market." [71]

In addition, over the course of this summer, it has become apparent that the Governing Boards are not functioning as they were intended to. Members of the ISO Board, in particular, have come under undue pressure from various sources, notably regarding votes to change the purchase price cap level. One member even felt compelled to resign, and her parting words encouraged her colleagues "to find the determination to stand for the principle that the ISO must be independent of manipulation by any market participant." [72] Several other members also noted pressure "from people that are very powerful." [73] The Staff Report found indications that the Boards have been susceptible to influence by market participants, particularly by the interest that they represent. [74] Even California authorities have concerns about the Boards' independence. A joint Report to the Governor authored by the California Commission and the Oversight Board notes that the ISO and PX "are governed by boards whose members can have serious conflicts of interest." [75]

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[69] Staff Report at 6-17.

[70] September 12, 2000 Meeting, transcript at 107, 108 and 127.

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

[72] Letter of resignation of Camden Collins, dated July 3, 2000.

[73] California ISO Board of Governors Meeting minutes, 28 June 2000, p. 89.

[74] Staff Report at 6-17, 6-18.

[75] California's Electricity Options and Challenges: Report to the Governor, Executive Summary (continued...)

On this record, we have no choice but to conclude that the existing California ISO stakeholder board is ineffective and must be modified. The ISO is an institution that is central to the functioning of wholesale power markets in the West and, unless it is able to resolve matters in a timely manner and is independent from market participants, we cannot be assured that rates, terms or conditions of its jurisdictional services will be just, reasonable and not unduly discriminatory or preferential. The transmission assets that the ISO operates are a critical part of the interstate transmission grid located in the Western Interconnection which provide essential support to the electric market. Any failings by the ISO in its obligation to ensure reliable operation of the transmission grid would have grave consequences for the residents and business in the Western states. Operation of this interstate transmission grid must be controlled by an expert board which is free from the influence of any market participant or market segment.[76]

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

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

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

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[75](...continued)
at 3-4 (Joint Report).

[76]As noted in Order No. 2000, which expanded on our Order No. 888 ISO principles and experience with ISOs, independence is the bedrock principle of RTO formation.

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

The ISO and PX have well-established market monitoring units and independent surveillance committees that monitor their respective markets. This monitoring function focuses on trading activities and structural factors. In the October 30, 1997 Order, we accepted the ISO and PX proposal allowing market reports to be filed directly to regulatory agencies. [77] While these entities currently have the discretion to file their reports directly with the Commission, we propose that effective 60 days after the date of this order that all ISO and PX market reports be filed by the ISO and PX with the Commission at the same time that they are released to their respective boards. [78] This requirement will allow the Commission more timely information on market behavior.

4. Interconnection Procedures

While siting issues are not within this Commission's jurisdiction, we note that tariff interconnection policies are. Further, we note that standard procedures to facilitate the interconnection of new generators or existing generators seeking to increase the rated capacity of their facilities are needed in California. In this regard, we find that the ISO tariff lacks any such procedures and we direct the ISO to file generation interconnection procedures no later than sixty (60) days after the Independent Board is seated. This will ensure that the Commission may facilitate the matters under its control in a timely manner.

C. Longer-Term Measures

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

1. Reserve Requirement

Adequate reserves to ensure system reliability is closely related to establishing a price that elicits a supply response. Matters of planning reserve and reliability are ill-

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[77] 81 FERC at 61,552.

[78] This requirement is consistent with the recommendation in the Staff Report at 6-18.

suited to the lag inherent in a market response to short supplies. Attracting sufficient supply to maintain proper reserve requirements may well benefit from the imposition of planning reserve requirements to be met from forward markets. Suppliers would be able to build capacity with the financial assurance of long-term contracts and would be less tempted to wait until spot prices were driven up by low reserve levels. We direct the ISO and the Load Serving Entities in California to consider what market rules are needed to ensure that sufficient supply is available to meet loads and reserve requirements.

2. Alternative Auction Mechanisms

In times of adequate supply the single price auction disciplines prices by encouraging suppliers to bid their marginal costs so that they can be selected for dispatch and be paid the clearing price. However, in times of scarcity the single price auction can exacerbate the effect of supply shortages by allowing sellers who have small market shares to set the clearing price. Not only is the seller transformed into a price setter rather than a price taker, but the resulting price is ascribed to the entire market. We are concerned that given the current market in California, the single price auction may place little or no discipline on sellers during times of shortages by minimizing the risk of strategically bidding a small amount of supply for the purpose of raising the price of the entire market. It is for these reasons that we propose to mitigate prices by eliminating the use of a single price auction at prices above $150. While our proposed market reforms will mitigate some of the effects of the single price auction, we believe that further study of this issue is desirable and direct the PX and the ISO to consider, during the 24 month window, whether alternatives to the single price auction which minimize the ability of sellers to bid for the purpose of setting the clearing price may be appropriate.

3. Balanced Schedules

We are also concerned that some of the underscheduling problems may be a result of the existence of many individual scheduling coordinators that are required to submit balanced schedules to the ISO. We therefore direct the ISO and the PX to pursue establishing an integrated day ahead market in which all demand and supply bids are addressed in one venue.

4. Enhanced Market Mitigation

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

5. Congestion Management Redesign

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

More recently, in the August 23 Order, we stated that we would defer any consideration on the merit of the ISO's congestion management structure until the earlier of the ISO's filing of its reform proposal or the date which the Commission issues a supplemental order in this proceeding. While we consider the ISO's congestion management reform efforts to be crucial, we now believe that this particular aspect of the California market is not a significant source of this summer's high prices and volatility.[79]

We are however concerned about the delay caused by the existing ISO Board on this matter. Therefore we direct the new Independent ISO Board to file its redesign proposal no later than sixty (60) days after the Independent ISO Board is seated with an implementation date as soon as possible. The current congestion management system is fundamentally flawed and needs to be overhauled or replaced. This market redesign is crucial for providing transmission schedules that are based on physical reality and accurate price signals for the siting of new generation. Therefore we will require that the proposal, at a minimum, include a meaningful number of zones that significantly address congestion on the system. In this regard, we also require that the proposal provide a comparison with a nodal energy price proposal (i.e. locational marginal prices for each bus or node on the grid). We also expect the ISO to conduct a periodic (annual) review to evaluate the accuracy of the zones for congestion management. We will take any requisite action on that proposal at the time it is filed in a separate proceeding.

6. Demand Response Program

As the Staff Report observed, the difficulty with current demand response in California is that it is driven by administrative directive, not market prices. (Staff report at 5-21). We direct the ISO and Scheduling Coordinators to consider demand bidding programs in which loads can bid offers of demand reduction directly into the market to compete with offers of supply.

7. Importance of RTO Development and Compliance

As discussed earlier in this order, California is physically integrated into an extensive interstate transmission grid and has therefore been part of a western electricity market for a long time. California's markets will never realize optimal performance until the impediments to efficient utilization of the regional transmission grid are eliminated and the regional interstate transmission system is designed

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[79] In this regard we note that none of the recent reports or analyses of the events of the summer cite to the current congestion management structure as contributing to the high prices.

in such a way that it supports transparent, competitive Western bulk power markets - - markets that support all of the wholesale products that California requires, markets that remove impediments to efficient imports and exports, markets that eliminate rate pancaking and allow California to access more distant markets at a lower cost, markets that undertake regional transmission planning to ensure that the needs of California are considered when transmission expansions in other states are considered, and markets that allow regional market hubs like Palo Verde to develop where new generation can be located to serve multi-state markets. The Commission's RTO initiative is a response to fundamental changes in the electricity industry over the last 20 years. When fully implemented, RTOs will provide for operation and planning that will ensure consumer benefits for Californians and the citizens of other Western states. The problems being confronted in California can, in many ways, be traced to the continued balkanization of the Western grid and the absence of a true RTO with regional scope. The actions we have taken in this order are fully consistent with Order No. 2000, and nothing in this order relieves the ISO, PG&E, SOCal Edison or SDG&E from their obligation to make a filing in compliance with Order No. 2000 on January 17, 2001. We expect that the matters addressed in this order will move the California market toward meeting the significant objectives of Order No. 2000 and that these long-term market reforms will facilitate California's transformation into a properly sized and functioning RTO.

D. Price Mitigation and Refunds

The Commission has found in this proceeding that the existing market structure and market rules, in conjunction with an imbalance of supply and demand in California, have caused and, until remedied, will continue to have the potential to cause, unjust and unreasonable rates for short-term energy during certain time periods. While the Staff Report lists a number of factors that legitimately led to higher prices last summer,[80] it also recites market design problems that contributed to high prices and that may have provided incentives for the exercise of market power or otherwise led to higher than competitive prices.[81] As long as a flawed market design remains in effect, the possibility for non-

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

[81]The Staff Report cites market design problems including lack of forward contracting, inadequate demand response; underscheduling; and use of a single-price auction to establish price. See Staff Report at 5-9 to 5-18. The report shows that design problems may have provided incentives for the exercise of market power. See Staff Report at 5-9 to 5-26. While findings of specific exercises of market power are not in the record, the Staff Report refers at p. 5-20 to the analysis of the Market

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

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

1. Price Mitigation Measures

Between 1996 and 1999 California added about 700 MW of generation while its peak load grew by some 5,500 MW fueled by an annual population growth of 600,000 people and a robust economy. As a result, California's recent peak load and its available installed capacity (i.e., in-state capacity not down for maintenance) are effectively equal at about 45,000 MW; i.e., there is often barely enough supply to meet demand. This leaves California vulnerable to price spikes caused by even small suppliers who, under tight supply conditions, can affect the PX and ISO market clearing prices. These conditions can allow the exercise of market power. [82] These higher spot market prices in turn affect the prices in forward markets. While California has 8,000 MW of import capability, WSCC reserves during peak hours in May and June dropped to about 5 percent, compared to forecasted planning reserves of 17 - 20 percent issued earlier this year, and therefore less energy was

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[81](...continued)
Surveillance Committee (MSC) of the ISO, which estimated a significant degree of market power being exercised in California markets for the period October 1, 1999 to June 30, 2000. The MSC estimated prices for must-take energy over the entire period were 36.3% higher than they would have been under competitive conditions. For the last month of the sample, June 2000, they estimated that prices were 64.6% higher than they would have been under competitive conditions. The highest previous monthly market power index was in June 1998, when prices were estimated to be 39.9% higher than they would have been under competitive conditions. Average prices in August were higher than in June. While costs such as gas and NOx emissions rose, the report states that the numbers suggest that market power may have been exercised in June. With respect to all of the references in this footnote, the standard used to evaluate market power was bids above short-run marginal cost.

[82]Staff Report at 5-19.

available for purchase from out of state. [83] In addition, as virtually all reports on this market conclude, there is at present little demand responsiveness to price. Accordingly, we propose price mitigation in order to allow sufficient time for the implementation of the remedial measures we are proposing to order herein as well as the development of additional supply and demand response measures. As discussed, infra, the price mitigation measures will be in effect for a period of 24 months.

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

We propose to implement a temporary modification to the single price auctions of the PX and the ISO. A significant factor causing high prices in California was the fact that every MW in the market is priced at the market clearing price. We propose that, effective 60 days from the date of this order, for all short-term markets operated by the PX and the ISO (including the Replacement Reserve Market), the single price auctions be used for all sale offers at or below \$150. [84] This auction modification imposes no limits on a seller's bid and only limits which bids can set the clearing price. The single market clearing price will be used for the amount of load which clears at or below this amount in the auctions. To the extent an auction does not clear at or below the \$150 bid level, suppliers who choose to bid above \$150 will be paid their as-bid price. [85] These prices will be averaged and billed to

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

[84] In order to encourage the expansion of Demand Response programs, we will not extend this market reform to bids for load response.

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

all the load which was supplied in the auction.[86] Allowing generators to receive their as-bid price should permit generators whose costs exceed $150 to participate in the market and continue to attract new supply by reflecting in prices the true cost of scarcity.[87] This pricing method takes care to mitigate prices by reflecting a price to sellers at the margin which signals the supply and demand conditions rather than reverting to a traditional cost of service basis (i.e., a regulated price which reflects the cost of all assets without any regard to market conditions). This is crucial in order to induce new supply. Bids using this modified single price auction will continue to be disciplined by low and moderate cost suppliers bidding their marginal costs at times other than shortages to ensure that they are chosen for dispatch and can receive the clearing price. At times of shortage, we will discipline prices through reporting requirements and monitoring as discussed below.

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

In addition, to adequately monitor the competitiveness of markets during the 24-month period and ensure just and reasonable rates during the time it takes to effectuate the longer term structural and market rule remedies, we propose to condition the public utility sellers' market-based rate authority by requiring each seller to file on a weekly basis each transaction in the ISO and PX spot markets that

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

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

exceeds $150 effective sixty (60) days after this order. We propose to require all transactions for the prior week to be filed on a confidential basis to the Commission's Division of Energy Markets in a single report submitted on the Wednesday following the end of the transaction week (ending midnight Sunday). These market data should include the name of the seller, the price and amount of MWs covered by the transaction, the hour(s) covered by the transaction and the incremental generation cost. The filing may also identify legitimate opportunity costs that are known and verifiable that the seller considered in developing its bid, i.e., prior to the transaction. These data will be used to monitor prices on a more current basis, in order to detect potential exercises of market power or otherwise non-competitive market prices and to adjust transaction prices, if necessary, to establish just and reasonable rates.

We recognize that some parties have offered alternative price mitigation measures and our decision here is informed by those alternative proposals. We believe that a comparison of the major attributes of some alternatives that have been proffered shows that the option we have selected is appropriate. For example, some parties propose that bids into the single price auction be capped at a specific level. Recognizing that the single price auction magnifies the impact when the maximum bid does not reflect the competitive outcome, by paying that same price to all sellers in the market, proponents of these measures seek lower and lower ceilings to reduce the economic consequences. However, ceilings set too low can also have severe short-term and long-term consequences on the market. Recognizing these concerns, some alternative proposals would include load-differentiated price caps that are indexed to estimated load and changes in input costs. These proposals, however, introduce significant complexity into a market that is already in dire need of simplification. We believe that our approach addresses the concerns that underlie these alternatives.

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

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

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

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

We also select $150 as a reasonable benchmark for the cost consequences of a tight supply. Existing gas fired units [88] were operated at unprecedented levels, driving up the price of NOx emission allowances from around $6/lb. to over $40/lb. at the end of August. [89] In addition, gas prices have risen from $2/MMBtu in the spring to about $5/MMBtu now. [90] The $150 figure will accommodate these marginal running costs for a combined cycle generating unit and permits some contribution to fixed costs . [91] As a result, existing suppliers and new entrants whose marginal costs allow them to bid within these parameters will not be burdened by reporting requirements. This will minimize our intrusion in these markets and should attract new suppliers. Those suppliers who cannot accommodate their financial needs at or below this breakpoint will be paid the as-bid price, but will be required to report so that we can monitor their bids.

Prices based on traditional cost of service are incompatible with fostering a competitive market because the cost of the assets will not reflect supply or demand conditions. In choosing our price mitigation approach, it is our intent to guide these markets to self-correct, not to reintroduce command and control price regulation. Monitoring bids above the $150 breakpoint will allow the market to

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[88] Natural gas comprises about 55 percent of California's fuel mix.

[89] Staff Report at 3-21.

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

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

respond over the next 24 months by ensuring that prices reflect the cost of scarcity while allowing us to mitigate potential market power.

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

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

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

A. Refund Liability For the Period October 2, 2000 Through December 31, 2002

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

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

We are not now proposing to order any refunds. However, having now reviewed the price volatility that has occurred in California and the flaws in the market design that can lead to unjust and unreasonable rates during certain time periods, we propose that sellers remain subject to potential refund liability during the period it takes to effectuate the longer term remedies proposed herein. We must be vigilant that market manipulation or other anticompetitive behavior does not occur and that the combination of market rules and supply shortage does not otherwise produce unjust and unreasonable rates while the flawed market design remains in effect. Thus, we conclude that not only is the market monitoring through increased reporting, discussed previously, appropriate, but circumscribed refund liability also is appropriate. Therefore, if the Commission finds that the wholesale markets in California are unable to produce competitive, just and reasonable prices, or that market power or other individual seller conduct is exercised to produce an unjust and unreasonable rate, we may require refunds for sales made during the refund effective period. However, should we find it necessary to order refunds, we will limit refund liability to no lower than the seller's marginal costs or legitimate and verifiable opportunity costs. This will achieve an appropriate balance between ratepayer protection and the seller's ability to have an opportunity to recover its costs.

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

B. Refund Liability for Period Prior To October 2, 2000

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

The Staff Report, our own San Diego hearing, and all the facts collected about this summer's market dysfunctions attest to the unanticipated hardship imposed on California ratepayers. The rate shocks were severe and unanticipated by consumers. We understand the distress of San Diegans, the concerns of their public representatives, and the adverse impacts on certain sectors of the local economy, but these factors cannot alter the limitations on the Commission's authority to change rates that were previously approved, even if subsequently found to be unjust and unreasonable. The FPA and the weight of court precedent strongly suggest that retroactive refunds are impermissible in these circumstances. See Appendix E. The Congress has refrained during the 65-year history of the FPA from granting such authority in part because of the uncertainty it would create in regulated wholesale markets for power. The FPA itselfwas created, not to redress traumatic and inequitable circumstances like this, but to provide rate certainty in a relatively static monopoly environment. It may be argued that the dynamic power markets of today may warrant changes in the Commission's refund authority, at least for extreme circumstances, but that does not help the Commission today as it considers rate relief to the citizens of San Diego for the summer just past.[92]

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

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

Consistent with the above discussion, we will reject the price cap proposed by the PX and the purchase cap amendment filed by the ISO. While the ISO purchase price cap has served to mitigate price volatility in both the ISO and PX markets, nonetheless it has served to disrupt the market by encouraging sellers to stay out of the PX's auction and wait for the ISO to make the needed purchases on an out-of-market basis at the last minute. As we noted in the August 23 Order,[93] all the PX and ISO markets are interrelated such that any significant modification to one market will affect the other markets. Our proposed modification to the single price auctions is intended to establish uniform pricing and remove incentives for the load and resources to participate in one market over another. For this reason we will not allow, at this time, either the PX or ISO to implement changes that will disrupt this uniformity or to introduce new incentives in the markets. Moreover, we are attempting to provide a period of stability in the market in order to encourage supply to enter the market. Therefore we will reject the PX and ISO proposals. In the interest of maintaining stability in the markets during the transition prior to imposing the instant market reforms, we hereby order that the current $250 ISO purchase cap remain in place at that level until sixty (60) days after the date of this order.[94]

We will sunset all price mitigation on December 31, 2002. We conclude that 24 months is sufficient to restore order to these markets. We discuss below several critical market corrections which

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[92] However, given the new and dynamic environment, the Commission is willing to explore any proposal for equitable relief, provided that it would ensure that California's electric markets remain capable of attracting investment while also mitigating the severe financial consequences of last summer's high prices.

[93] 92 FERC at 61,606.

[94] We leave undisturbed the ISO's $100 purchase price cap for Replacement Reserves during this time period.

must be addressed during the 24-month window and we discuss further the removal of the auction reform after this 24-month window.

F. Actions Others Should Take

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

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

1. Offering a Full Menu of Forward Products

As noted, many of the remedies we are proposing are intended to move loads into forward markets. Success in this objective is, of course, contingent on the availability of supply in forward markets. While we understand that the pricing offered for each type of forward product may vary to reflect the terms offered (e.g., length of contract, risk apportionment, peak vs off-peak), we fully expect that California suppliers will welcome the opportunity to offer a full range of forward products to meet the needs of their customers. To the extent that a full range of forward products (e.g., short-term, intermediate term and long-term products) do not become available in California, we expect that load-serving entities will bring that to our attention. Whether the Commission should require sellers to provide a certain percentage of product offerings in the forward market is one issue that the Commission will consider in this proceeding.

2. Additions of Generation and Transmission Capacity

There is little doubt that the most crucial task ahead is to ensure that a robust supply enters this market, both now and in response to any future price signals. The Staff Report underscores inadequate siting of generation and transmission as a key structural defect in California. We have made every effort in this order to eliminate market design flaws in a manner that promotes efficient markets in order to reduce consumers prices to the extent possible given the current inadequate supply. However, prompt access to new generation is needed to ensure full consumer benefits are realized. For that reason, we have also carefully crafted our proposed remedies so as to avoid circumstances that may deter new entry, e.g., prices set too low can prevent new entry, indecisiveness about the specifics of market reforms and price mitigation can deter new entry, and market rules that place restrictions on the operation of efficient markets can deter new entry. [95]

However, the Commission's authority does not extend to siting, and without appropriate siting support, consumers in California will continue to pay higher prices due to inadequate generation supply. The 24-month price mitigation we have ordered herein will afford the state and local agencies a window to streamline, facilitate and accelerate the siting of needed generation and transmission, including the specific projects identified in the Staff Report as furthest along in the planning and siting process and, therefore, most likely to be completed in the shortest time. [96]

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

3. Demand Response

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

4. Elimination of Impediments to Forward Contracting

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

[96] See Staff Report at 5-7 - 5-8, citing California Energy Commission's reports on their website which has a listing of the proposed generation. The website is www.energy.ca.gov/sitingcases/projects_since_1979.html .

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

Hearing Based on Written Submissions and Oral Presentations to the Commission

In our August 23 Order, we did not determine the type of hearing that would be needed in this proceeding. Based on the information provided in the Staff Report and the submissions in the record thus far, and the nature of the issues presented, we conclude that a trial-type hearing is not necessary to resolve the matters before us. [97] Further, the need for expeditious resolution of the problems inherent in California markets call for as expeditious a hearing as possible, consistent with due process and the development of an adequate record. Accordingly, the Commission will provide the parties an opportunity to file comments, containing all arguments and all supporting evidence that they wish to present. All such comments must be filed by November 22, 2000, which is three weeks from the date of this order. Reply comments will not be entertained. In addition, the Commission will convene a public conference on November 9, 2000 for interested persons to discuss the proposed remedies. A transcript of this conference will be placed in the public record of this proceeding.

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

The Commission orders:

(A) The parties may submit to the Commission additional arguments and evidence as outlined in the body of this order, by November 22, 2000. A party's presentation should separately state the facts and arguments advanced by the party and include any and all exhibits, affidavits, and/or

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

prepared testimony upon which the party relies. The statement of facts must include citations to the supporting exhibits, affidavits and/or prepared testimony. All materials must be verified and subscribed as set forth in 18 C.F.R. § 385.2005 (2000).

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

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

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

By the Commission. Commissioners Massey and Hébert concurred with separate statements attached.

(S E A L)

David P. Boergers,
Secretary.

Appendix A - Timely Intervenors in ER00-3461-000

California Department of Water Resources
California Electricity Oversight Board
Duke Energy North America L.L.C., Duke Energy Trading and Marketing, L.L.C., and Duke Energy Merchants, L.L.C. (jointly)
Dynegy Power Marketing, Inc.
El Paso Merchant Energy, L.P.
Enron Power Marketing, Inc. and Enron Energy Services, Inc. (jointly)
Independent Energy Producers Association
Morgan Stanley Capital Group, Inc.
Pacific Gas and Electric Company
Public Utilities Commission of the State of California
Reliant Energy Power Generation, Inc.
Southern California Edison Company
Southern Energy California, L.L.C., Southern Energy Potrero, L.L.C. and Southern Energy Delta, L.L.C. (jointly)
Western Power Trading Forum
Williams Energy Marketing & Trading Company

Appendix B - Timely Intervenors in ER00-3673-000

California Department of Water Resources
California Electricity Oversight Board
California Power Exchange
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)
City of San Diego, California
Duke Energy North America L.L.C., Duke Energy Trading and Marketing, L.L.C., and Duke Energy Merchants, L.L.C.(jointly)
Dynegy Power Marketing, Inc.
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly)
Independent Energy Producers Association
Merrill Lynch Capital Services, Inc.
Metropolitan Water District of Southern California
Modesto Irrigation District
Morgan Stanley Capital Group, Inc.
Northern California Power Agency
Pacific Gas and Electric Company
PPL EnergyPlus, LLC and PPL Montana, LLC (jointly)
Reliant Energy Power Generation, Inc.
Sacramento Municipal Utility District
Southern California Edison Company
Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly)
Transmission Agency of Northern California
Turlock Irrigation District
Western Power Trading Forum
Williams Energy Marketing & Trading Company

Appendix C - Parties to the Consolidated Hearing Proceeding

AES Pacific, Inc.
Arizona Districts
Automated Power Exchange, Inc.
California Department of Water Resources
California Electricity Oversight Board
California Independent System Operator Corporation
California Large Energy Consumers Association
California Manufacturers and Technology Association
California Power Exchange
Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (jointly)
Cities of Redding, Santa Clara, and Palo Alto, California, and the M-S-R Public Power Agency (jointly)
City of Dana Point, California
City of Escondido, California
City of Poway, California
City of San Diego, California
City of Vernon, California
City of Vista, California
Cogeneration Association of California and Energy Producers and Users Coalition (jointly)
Duke Energy North America LLC (together with Duke Energy Trading and Marketing, LLC and Duke Energy Merchants, LLC)
Dynegy Power Marketing, Inc.; El Segundo Power, LLC; Long Beach Generation, LLC; Cabrillo Power I LLC; and Cabrillo Power II LLC (jointly)
El Paso Merchant Energy, L.P.
Electric Power Supply Association
Enron Power Marketing, Inc., and Enron Energy Services, Inc. (jointly)
Independent Energy Producers Association
Merrill Lynch Capital Services, Inc.
Metropolitan Water District of Southern California
Modesto Irrigation District
Morgan Stanley Capital Group, Inc.
New York Mercantile Exchange
Northern California Power Agency
Public Utilities Commission of California (California Commission)
Pacific Gas and Electric Company
Pinnacle West Companies
Portland General Electric Company
PPL EnergyPlus, LLC and PPL Montana, LLC (jointly)
Reliant Energy Power Generation, Inc.
Sacramento Municipal Utility District
Southern California Edison Company
Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly)
The Utility Reform Network
Transmission Agency of Northern California
Western Power Trading Forum
Williams Energy Marketing & Trading Company

Appendix D

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

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

Section 2 of the report finds tight supply and demand conditions existed throughout the west during most of this summer, with emergency conditions concentrated in California. Broadly speaking,

- Overall demand across the WSCC increased significantly driven by hot weather and load increases that were heat sensitive and that were also driven by increased economic activity. Average summer loads were 11 percent higher in May and 13 percent higher in June from the previous year. Energy consumption also increased across the WSCC by 5 percent in May and approximately 10 percent in June from the previous year. Off-peak demands in the ISO increased significantly during the summer, in large part to meet increased pumping demands for hydro power facilities, needed for peaking purposes both inside and outside of California. However, peak demand in the ISO area fell slightly, partially reflecting response to emergency declarations and actions.

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

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

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

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

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

- Prices in the ISO spiked in May and June and average June prices reached record high levels. While an ISO price cap of $750 existed during the early part of the Summer, prices became highly volatile and the hourly price hit the cap of 3 days in June. Average June prices reached record levels of $120 in the PX.

- Average prices were lower in July and June, but total costs paid by purchasers in August were higher than June. Caps of $500 in July and $250 in August had a dampening effect on high hourly prices, but average prices in August rose to $166 in the PX after falling below June levels to $106 in July. The lower caps may have played a role in increasing exports in July and August.

- Prices at other trading hubs in the West generally correlated with California prices suggesting that opportunities to sell at high prices existed in these regions when California prices were high. However, it is not yet clear how scarce supplies were in these regions or to what extent prices outside California were from California imports rather then consumption in other regions. While information for certain weeks in the West indicated supply was scarce, it was not possible to make an overall assessment on scarcity throughout the West without additional information.

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

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

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

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

Section 5 discusses the issues that were raised as possibly causing the high prices of this summer. These fall into three general categories: (a) competitive market forces, (b) market design problems and (c) market power. The data clearly show that a general scarcity of power in the West and increased costs to produce power were factors causing these high prices. It is also clear that existing market rules exacerbated the situation and contributed to the high prices. The data also indicate some attempted exercise of market power, if the standard of bidding above marginal cost is used, and some actual market power effects, to the extent that prices, at least in June, were significantly above competitive levels. The prices, at least in June, were significantly above competitive levels. However, the data do not isolate specific exercises of market power or suggest that the exercise of market power was more important than other primary explanatory factors.

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

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

Appendix E

Analysis of the Commission's Retroactive Refund Authority Under the Federal Power Act

I. Executive Summary

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

The issue of retroactive refunds was expressly considered by Congress in 1935 and again in 1988. In 1935, Congress rejected a provision that would have given the Commission authority to order refunds for any amounts found to be unreasonable or excessive. Instead, the 1935 Act authorized the Commission to change existing rates (as distinct from section 205 authority to suspend proposed rate increases) prospectively only – i.e., refund relief was available only after the Commission found that existing rates were unjust or unreasonable. The amendment to section 206 enacted in the 1988 Regulatory Fairness Act permitted limited retroactive refund authority – i.e., from the refund effective date forward.

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

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

II. Legal Analysis of Refund Authority

A. Statutory Provisions

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

1. Section 205

Section 205(a) provides that all rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is declared to be unlawful.[98] Section 205 also requires that, absent waiver, a public utility filing any changes in its rates, charges, classifications, or services must provide at least 60 days' prior notice, and permits the Commission to suspend the effectiveness of any such change for a period no longer than five months. Section 205(e) provides that the Commission "upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified." Thus, refunds under section 205 are limited to the period beginning with the allowed effective date of the proposed rate change and are also limited to the difference between the proposed increased rate and the pre-existing rate.

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

2. Section 206

Section 206 provides that if, upon complaint or upon its own motion, the Commission finds that existing rates, charges or classifications are unjust, unreasonable, or unduly discriminatory or preferential, it must determine, and order implementation of, a just and reasonable rate. In 1988, in the

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[98] Section 205(b) provides that:

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

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

Regulatory Fairness Act (RFA),[99] Congress substantially revised section 206 to permit limited authority to order retroactive refunds of rates found to be unjust and unreasonable. Under section 206, as amended by the RFA, upon instituting a proceeding under section 206, the Commission must establish a refund effective date. In the case of a proceeding instituted upon complaint, the refund effective date cannot be earlier than the date 60 days after the filing of such complaint nor later than 5 months after expiration of such 60-day period. In the case of a proceeding instituted upon the Commission's own motion, the refund effective date cannot be earlier than the date 60 days after publication by the Commission of notice of its intention to initiate such proceeding, nor later than 5 months after the expiration of such 60-day period. At the end of any such proceeding, the Commission may, in its discretion, order refunds if it finds that the existing rate is unjust, unreasonable or unduly discriminatory or preferential. Possible refunds are limited to the period from the refund effective date through a date 15 months after such refund effective date and are also limited to the difference between the rate charged and the rate determined to be just and reasonable.

On its face, section 206 does not provide the Commission authority to establish a refund effective date that is earlier than 60 days after the date that a complaint is filed or the Commission investigates an investigation. Further, section 206 does not contain any provision authorizing the Commission to order refunds for periods prior to the refund effective date. Therefore, section 206 does not expressly afford retroactive refund relief for rates covering periods prior to the filing of a complaint or the initiation of a Commission investigation even if the Commission determines that such past rates were unjust and unreasonable.[100]

B. The Legislative History of Section 206

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

1. The 1935 Act

The originally proposed bill that led to the 1935 FPA had contained a provision (section 213) which would have allowed the Commission, upon complaint, to "order that the public utility make due

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[99] 102 Stat. 2299 (1988). The RFA amendments to section 206 are discussed infra.

[100] As discussed in Section C.2., infra, under the Commission's and the courts' interpretations of section 206, there are limited circumstances in which the Commission can order refunds for past periods.

reparation . . . with interest, for amounts charged by an electric utility which were thereafter found to be unreasonable or excessive." S. 1725, 74th Cong., 1st Sess. at 43 (1935).[101] This provision was eliminated from the final bill while in committee, as it was considered appropriate for a state utility law, but not "applicable to one governing merely wholesale transactions." S. Rep. No. 621, 74th Cong. 1st Sess. 20 (1935) (emphasis added). Based upon the foregoing, it is apparent that Congress drew a distinction between retail and wholesale electric rate regulation as to the authority required by a regulatory agency to adequately protect consumers of electric energy. The reason underlying this distinction was not explicitly stated when the legislation was reported out of committee. Nonetheless, certain testimony from the hearings held in connection with the legislation sheds some light on this subject, as set forth below.

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

> The next amendment, we ask that section 213, beginning on page 118, be stricken out.
>
> That is the reparation provision brought in from the Interstate Commerce Act. It provides that if service taken has been charged for at an unreasonable or excessive rate, and if within 2 years an application is made to the Commission, it may disapprove the rate charged and fix a reasonable rate, and require the selling utility to make due reparation to the complainant.

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[101] Proposed section 213 read as follows:

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

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

Id.

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

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

Id. at 420 (emphasis added).

Based upon the foregoing, it appears that section 213 was included in the proposed legislation submitted to Congress by the Federal Power Commission as a standard utility law provision borrowed from the Interstate Commerce Act. It further appears that Congress accepted the argument set forth by the General Solicitor of NARUC that wholesale customers of electric utilities should not be permitted to accept service for up to two years without complaint and thereafter be permitted reparations covering that period. However, Congress did not explicitly accept the General Solicitor's alternative suggestion that the time period for recovery of reparations should commence with the filing of the complaint, and instead eliminated section 213 entirely. As discussed infra, this resulted in the courts later concluding that Congress intended that the Commission have authority to only grant relief ir a section 206 proceeding prospectively from the date of its order, [102] and it also led to Congress providing limited retroactive refund authority in the RFA of 1988.

2. The Regulatory Fairness Act of 1988

The Senate Report on the RFA [103] contrasted the Commission's refund authority under sections 205 and 206. It noted that section 205 proceedings on average required one year for resolution and that final decisions by the Commission are retroactive to the effective date of the rate increase. With respect to section 206, the Senate Report stated:

> Section 206 of the FPA allows the Commission, on its own motion or pursuant to complaint, to set a "just and reasonable rate" if it finds the rate in effect to be unlawful. Under existing law, a rate reduction under section 206 differs from a rate increase under section 205 in two important ways. First, a motion or complaint for rate reduction does not take effect automatically after a given period of time as does a request for rate increase. Second, under section 206 a rate reduction is prospective only.
>
> Resolution of section 206 proceedings requires two years on average. One probable reason for the longer period needed to resolve such proceedings is that public utilities have no incentive to settle meritorious section 206 complaints since any relief is prospective. Under present law, public utilities keep revenues collected during the pendency of a section 206 proceeding, even if those revenues are subsequently determined to be excessive. H.R. 2858 would correct this problem by

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[102] See, e.g., City of Bethany v. FERC, 727 F.2d 1131 (D.C. Cir. 1984), cert.denied, 469 U.S. 917 (1984).

[103] The House passed H.R. 2858, a Senate Committee amended the House-passed bill, and the Senate passed H.R. 2858, as amended.

> giving FERC the authority to order refunds, subject to certain limitations. [[104]]

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

The Senate Report also explains that the burden of proof was unchanged by the RFA, i.e., the Commission or a complainant has the burden of proof to show that an existing rate, charge or related provision is unlawful and that the proposed rate is just and reasonable. [105]

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

> As passed by the House of Representatives, H.R. 2858 required refunds to be paid subject only to a narrowly drawn public interest exception. The Committee amended the House-passed bill to make the granting of refunds under section 206 discretionary so as to parallel the refund provision of section 205 of the Federal Power Act. The Committee recognizes that it may not be appropriate in all instances to order refunds in the event that it is determined in a proceeding under section 206 of the Act that rates or charges are not just and reasonable.
>
> The Committee intends the Commission to exercise its refund authority under section 206 in a manner that furthers the long-term objective of achieving the lowest cost for consumers consistent with the maintenance of safe and reliable service.
>
> * * *
>
> The Committee is aware that there may be challenges to power pooling and system integration agreements brought under section 206 of the Federal Power Act in which refunds might not be appropriate, for example, where the issue relates to cost allocation among utilities, and the bill as reported by the Committee is intended to provide the

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[104] S. Rep. No. 491, 100th Cong., 2d Sess. 3-4 (1988), reprinted in 1988 U.S.C.C.A.N. 2685.

[105] S. Rep. No. 491 at 5, reprinted in 1988 U.S.C.C.A.N. 2687.

> Commission with the discretion needed to deal with individual instances in which refunds would not be in the public interest.
>
> In determining if a refund may adversely affect the public interest in the case of power pool agreements, the Committee expects the Commission to consider whether, and the extent to which, a refund would adversely affect decisions made on the basis of energy pricing provisions of such pooling agreements or will impose a substantial burden on the pool in comparison with the benefits of refunds to consumers.
>
> In addition to certain situations involving power pooling, there may be others in which the public interest would not be served by requiring refunds under section 206. Because the potential range of these situations cannot be fully anticipated, no attempt has been made to enumerate them here. In any case, the Committee generally expects the Commission to grant refunds under section 206 with comparable frequency to its granting of refunds under section 205. [[106]]

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

C. Court Precedent

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

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

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

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[106] S. Rep. No. 491 at 5-6, reprinted in 1988 U.S.C.C.A.N. 2687-88.

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

> [v]arious reasons have been offered in support of the filed rate doctrine, and its corollary prohibiting the regulatory agency from altering a rate retroactively. Most recently, the Court justified the doctrine as necessary to enforcement of the underlying statute (Maislin, 110 S. Ct. at 2769), in that case the Interstate Commerce Act. The Court has also described the considerations underlying the doctrine as "'preservation of the agency's primary jurisdiction over reasonableness of rates and the need to insure that regulated companies charge only those rates of which the agency has been made cognizant.'" Opinions of this court have cited "necessary predictability" as "the whole purpose of the well-established 'filed rate' doctrine . . . ." In the context of the Interstate Commerce Act, the Supreme Court has indicated that the doctrine fulfills "the paramount purpose of Congress" of preventing "unjust discrimination." Other courts of appeals have described the doctrine as intending "to prevent discriminatory rate payments" and as "reflecting a statutory bias in favor of retroactive rate reductions but not retroactive rate increases."
>
> Whatever the justification, it is generally agreed that with respect to the Federal Power Act, the filed rate doctrine rests on two provisions: section 205(c), which requires utilities to file rate schedules with the Commission, and section 206(a), which allows the Commission to fix rates and charges, but only prospectively [emphasis added]. [[107]]

The D.C. Circuit further explained that as the filed rate doctrine and rule against retroactive ratemaking "relate to purchasers, their guiding concern is '[p]roviding the necessary predictability,' allowing 'purchasers of gas to know in advance the consequences of the purchasing decisions they make.'" [108]

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[107] Towns of Concord, Norwood and Wellesley v. FERC, 955 F.2d 67, 71-72 (D.C. Cir. 1992) (citations and footnotes omitted) (Towns of Concord v. FERC). See also Natural Gas Clearinghouse v. FERC, 965 F.2d 1066, 1075 (D.C. Cir. 1992).

[108] Towns of Concord v. FERC, 955 F.2d at 75. See also Texas Eastern Transmission Corp. v. FERC, 102 F.3d 174, 188-89 (D.C. Cir. 1996) (filed rate doctrine "seeks to prevent customers from relying on certain rates, only to find later that their purchasing decisions have been upset and their costs increased."); Public Utilities Comm'n of California v. FERC, 988 F.2d 154, 164 (D.C. Cir. 1993) ("when determining whether a FERC order violates either the filed rate doctrine or the rule against retroactive ratemaking, this court inquires whether, as a practical matter, the purchasers of the [energy] had sufficient notice that the approved rate was subject to change.").

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

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

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

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

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

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

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

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

There are, however, some limited circumstances under which the Commission can order refunds for past periods. For example, where the Commission has conditionally accepted for filing a formula rate (such acceptance is subject to the condition that the Commission may, at a later date, retroactively order refunds with respect to certain costs impermissibly charged through the formula) and the utility has charged impermissible costs through the formula, or where the rates charged were contrary to the filed rate, the Commission may order refunds. See, e.g., Appalachian Power Co., 23 FERC ¶ 61,032 at 61,088 (1987). The Commission may also be able to order refunds as a remedy to correct legal errors found by an appellate court upon judicial review of a Commission order on a requested rate change. United Gas v. Callery Properties, 382 U.S. 223, 229 (1965) (while the Commission has no power to make reparation orders, its power to fix rates being prospective only, it is not so restricted where its order, which never became final, has been overturned by a reviewing court); Reynolds Metals Co. v. FERC, 777 F.2d 760, 763 (D.C. Cir. 1985); see Public Utilities Commission of the State of California v. FERC, et al., 988 F.2d 154, 161-162 (1993) (allowing pipeline to seek retroactive recovery of costs based on court reversal of FERC order, citing "general principle of agency authority to implement judicial reversal"). In Office of Consumers Counsel v. FERC, 826 F.2d 1136 (D.C. Cir. 1987), the court held that where the Commission had committed legal error in failing to order rate relief to consumers, [109] rate relief dating back to the date of the Commission's error would not violate section 5 of the NGA [110] since this would place consumers in the same position they would have occupied had the error not been made. [111] See also Tennessee Valley Mun. Gas Assn. v. FPC, 470 F.2d 446, 453 (D.C. Cir. 1972) (granting of refunds did not violate anti-reparations language in the statute which was designed to protect established expectations under legally established rate schedules; one "cannot claim justifiable reliance or protectable expectations based on [Commission] action which was illegal").

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

No distinction between cost-based and market-based rates is made in the FPA. Indeed, the statute itself does not dictate or even indicate how the Commission is to establish rates. Nor have courts found the Commission to be "bound to the use of any single formula or combination of formulae in determining rates." FPC v. Hope Gas Co., 320 U.S. 591, 602 (1944); see Duquesne Light Co. v.

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[109] The court determined that the Commission had committed legal error.

[110] 15 U.S.C. § 717d (1994). Section 5 of the Natural Gas Act is analogous to section 206 of the FPA.

[111] In Exxon Co., U.S.A. v. FERC, 182 F.3d 30, 49 (D.C. Cir. 1999), the court held:

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

Barasch, 488 U.S. 299, 310 (1988) (same). Section 205(c) of the FPA is clear, however, that all rates and charges for jurisdictional transactions must be on file with the Commission. Further, a Commission-approved rate, whether cost-based or market-based, may not be changed, except as provided by sections 205 and 206 of the FPA. The refund provisions of sections 205 and 206 of the FPA thus would appear to apply equally to both cost-based rates and market-based rates. Similarly, the filed rate and retroactive ratemaking doctrines, which derive from the requirements of sections 205 and 206, would appear to apply equally to cost-based and market-based rates. There is no court or Commission precedent that addresses the question directly, however.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,

Complainant,

v. — Docket No. EL00-95-000

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

Respondents.

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

(Issued November 1, 2000)

MASSEY, Commissioner, concurring:

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

First, our order finds that the California wholesale market has produced wholesale prices for electricity that are unjust and unreasonable, and that remedies are necessary. On August 23d, in voting on the complaint filed by San Diego Gas & Electric, I reached this conclusion and set forth my opinion in a separate written statement. Although I have

001101-0497-1

maintained an open mind on all issues during the course of our subsequent investigation, I am convinced that any reasonable interpretation of the record now before us today leads to this same conclusion.

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

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

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

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

Should we, for example, require sellers during the two-year mitigation window to forward contract with California load serving entities a certain percentage of their supply? In a recent pleading styled an Offer of Settlement, the California ISO suggests a forward contracting requirement of 70%. Should the Commission require a certain amount of forward contracting as a temporary measure to mitigate market power in spot markets? Should such an obligation be placed on sellers or buyers, or both? Should the Commission specify a certain level, or does this unnecessarily intrude into business arrangements? During our recent hearing in San Diego, Professor Frank Wolak, Chairman of the ISO's Market Surveillance Committee, suggested that the Commission define a forward contract of 18-24 months duration, set a just and reasonable price for such a contract, and attempt to reach agreement with the California PUC that purchasing such a contract would be deemed prudent. I would appreciate comments on the viability of this concept as well.

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

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

Our order deals with other important issues. With respect to the issue of retroactive refunds for last summer when prices were very high, our Office of General Counsel has prepared a legal memorandum that concludes that the Commission has no authority to order refunds for any period of time before October 2, 2000. I realize that this is an issue of utmost importance to the residents of California. This agency must act within the authority delegated by law, and the Congress has not given us this authority, according to our legal staff. Today's order concludes, however, that the Commission would consider any equitable remedies that parties wish to propose in this area. I interpret this language among other things to invite comment on the extent of the Commission's authority in the area of refunds. Has our legal staff reached the correct conclusion? Are there legal precedents or arguments that we have overlooked or misconstrued? This is such an important issue that we should use the comment period to ensure that we reach the correct conclusion with respect to the scope of our refund authority.

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

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

William L. Massey

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company

v. Docket No. EL00-95-000

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 November 1, 2000)

HÉBERT, Commissioner, *concurring:*

Introduction

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

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

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

Nevertheless, on balance, today's order appears to be a step in the right direction. For this reason, I hesitantly concur. However, there remains much uncertainty as to the

001101-0498-1

practical effect of various remedial measures adopted in today's order. I can support the order only because it does not represent the last word; it is merely a "proposed" order. A technical conference and a round of comments from the public will follow. If, after listening to comment on the subject, I am convinced that the Commission has moved in the wrong direction – and I am perilously close to that conviction right now – I will not be hesitant to upset the basket of remedial measures adopted today.

I write separately to present for comment the basket of remedial measures I would adopt, if given the chance. I agree with today's order to the extent it explains that California electricity markets suffer from serious structural defects that inhibit the operation of a competitive market. I also agree that the current situation requires "decisive" action; otherwise, California markets will not move toward the goal we all agree on. The Commission needs to act now to ensure that energy suppliers have an incentive to enter capacity-starved California markets, that local utilities have strong reason to hedge against price risk, that entrepreneurs have a motivation to develop new products and technologies, and that consumers share a motivation to conserve.

I simply disagree with today's order with respect to its selection of corrective measures. Some will help; others will hurt. Others not selected would have helped more. The Commission should have stopped with corrective measures designed to remove impediments from the operation of a competitive market. Instead, unfortunately, it decided to go farther and adopted additional measures that prescribe with tremendous specificity how market institutions and market participants should act during the transition period to a fully competitive market. The majority of the Commission believes that various prescriptive measures will ease the pain felt by market participants during what it believes will be a two-year transitional period.

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

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

Remedial Measures I Would Adopt

1. Eliminate All Price Controls

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

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

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

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

Unfortunately, the Commission does not stop here. Instead, it proceeds to take additional "mitigation" action that belies its stated intention to allow competitive markets to send price signals to suppliers and customers.

2. Abolish the Single Price Auction

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

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

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

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

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

3. <u>Terminate the Mandatory Buy-Sell Requirement in the PX</u>

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

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

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

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

Today's order expends many pages addressing numerous other flaws in the California market design. Specifically, the order discusses reserve requirements, congestion management redesign, reliability and operational measures, governance structures, demand response, balance scheduling, generation interconnection, and market monitoring and mitigation. The Commission requires specific responses to certain of its concerns. It directs market institutions and participants to consider and report back on other concerns.

I am greatly concerned that the Commission, in its desire to appear active and engaged, is greatly undermining the ability of the ISO and PX to make its regional transmission organization (RTO) filing. That filing is due to be filed no later than January 16, 2001 – only 2 ½ months from now. I have no problem with the Commission identifying its concerns in this order. However, I would ask the ISO and PX to take these concerns into accounts when they make their RTO filing. By asking the ISO and PX to act immediately on some measures, relatively soon (short-term) on other measures, and somewhat more leisurely (long-term) on still other measures, the Commission is greatly inhibiting the ability of the PX and ISO to respond effectively to their RTO filing obligation. The Commission is also hindering, and in some cases pre-judging, its ability to act on that filing once received.

Remedial Measures I Would Not Adopt

1. Modify the Single Price Auction

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

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

If the Commission is insistent that it must have a single price auction dollar figure in place, I would not leave it at that figure for the entire period of the transitional period. Rather, I would escalate that figure upward by specific amounts (say, $250 or $500 amounts) at specific intervals (say, every six months). In this manner, California market participants and institutions, in conjunction with California regulators and legislators, will have the incentive to respond immediately to the market design flaws identified in today's order. For example, the Commission has no authority to direct the state of California to expedite its siting and permitting procedures, or to drop remaining impediments to forward contracting. A price cap escalator, however, would act to spur all market players to adopt new and badly-needed remedial measures

2. Disband Stakeholder Boards at This Time

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

Despite all of my misgivings, I would not proceed, as the Commission does today, to dictate right now how the Governing Boards should be restructured. Governance and independence are topics, I presume, that the ISO and PX are vigorously debating as they prepare their RTO filing. They very well may decide to adopt the independent, non-stakeholder governance structure preferred by the Commission in today's order. But, then again, they may not. This is ultimately a matter to be addressed by the ISO and PX, after consultation with various market participants, in the first instance and for the Commission to consider only after receiving the California RTO filing.

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

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

Finally, the Commission is needlessly provoking a constitutional show-down. The Governing Boards are the product of legislative decisionmaking. As a practical matter, I doubt they can be replaced in the time frame contemplated in today's order. Moreover, left unexplained is what the Commission intends to do if the ISO and PX balk at the requirement to adopt immediately a non-stakeholder governance structure. This is precisely the reason why the governance structure should be negotiated and worked out in the context of the collegial RTO process – not determined immediately by regulatory fiat.

3. Dictate to Market Participants How Best to Manage Risk

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

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

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

Refunds

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

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

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

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

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

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

As for refunds for future periods, today's order informs power suppliers that their sales into California ISO and PX markets are now "subject to refund." I addressed the practical effect of "subject to" language in my concurrence to the August 23 order initiating the Commission's investigation into California markets. 92 FERC at 61,611. I believe that the inclusion of "subject to" language will act to exacerbate supply deficiencies in California. This is because power suppliers, uncertain whether the Commission later may decide to alter the rate they have charged, justifiably will decide to sell their capacity in markets outside California. This will only accelerate the exodus of power outside California, a factor recognized by the Staff Report as contributing to the summer increase in the wholesale price of electricity.

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

To address credible claims of anticompetitive behavior, I would employ the Federal Power Act as it was drafted and promulgated, not as it arguably should be revised to recognize modern-day power sales. I continue to believe that the Commission should act vigorously to detect and remedy real abuses of market power. If a complaint or Commission staff-initiated investigation can establish, to the Commission's satisfaction, such an abuse, the Commission should order refunds prospective from the date of that complaint or investigation. By directing the imposition of a "subject to refund" condition on California sellers of power, the Commission now goes beyond the limitations of the FPA by allowing for the potential award of refunds for conduct prior to the filing of a complaint or the initiation of an investigation.

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

Conclusion

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

For all of these reasons, I respectfully concur.

Curt L. Hébert, Jr.
Commissioner

Committee on Governmental Affairs
EXHIBIT #A-54

Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities

Part I of Staff Report on U.S. Bulk Power Markets

November 1, 2000

The analyses and conclusions are those of the study team and do not necessarily reflect the views of other staff members of the Federal Energy Regulatory Commission, any individual Commissioner, or the Commission itself.

Contents

Tables

Figures

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1. Overview

This investigation of the western bulk power market began at the direction of the Commission in an undocketed order issued July 26, 2000. The Commission directed staff to undertake a fact finding mission of the conditions in the electric bulk power markets in all regions of the country, including volatile price fluctuations in some regions. Specifically, staff was to (a) determine any technical or operational factors, regulatory prohibitions or rules (federal or state), market rules, or other factors affecting competitive pricing of the electric energy or the reliability of service and (b) report its findings to the Commission by November 1, 2000.

Wholesale prices increased significantly over the summer in the West and residential and other retail consumers in the San Diego area saw these prices passed directly to them. In response to a complaint filed by San Diego Gas & Electric, on August 23, 2000, the Commission initiated a parallel investigation under Section 206 of the Federal Power Act.[1] The Commission directed staff to accelerate its fact-finding investigation of the markets in California and the Western region and report to the Commission as soon as possible. This is staff's report of its findings.

The focus here is primarily directed toward answering the questions, why prices behaved the way they did and what should be done about it. In terms of general methodology, we reviewed public data maintained at the Commission and used other public sources to establish the general framework of the markets in California and the rest of the Western Systems Coordinating Council (WSCC). We conducted interviews with market participants, state regulators, outside economists, entities representing retail customers, the Independent System Operator (ISO) and the Power Exchange (PX) to obtain further input.[2] The staff then attempted to substantiate issues raised during the interviews regarding the market from the sources available to it and obtained data from market participants, the ISO, the PX and the WSCC.

This was an informal investigation. As such, staff did not depose market participants or others as it might as part of a formal investigation. Given the purpose, to find the general cause of the unusual prices and market activity, this was not necessary.

Finally, from a methodological standpoint, staff studied the issues from the perspective of both California and the entire WSCC, as events in one relate to the other. California, as a consistent net importer of electricity during peak periods, relies on sources

[1] San Diego Gas & Electric Co., 92 FERC ¶ 61,172 (2000) rehearing pending.

[2] A list of groups interviewed is attached in Appendix A.

and markets outside of its boundaries. Consequently, the surrounding markets in the rest of the WSCC are greatly influenced by events and market rules in California.

Brief Overview of Conclusions

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

Section 2 of the report finds tight supply and demand conditions existed throughout the West during most of this summer, with emergency conditions concentrated in California. Broadly speaking,

- *Overall demand across the WSCC increased significantly driven by hot weather and load increases that were heat sensitive and that were also driven by increased economic activity.* Average summer loads were 11 percent higher in May and 13 percent higher in June from the previous year. Energy consumption also increased across the WSCC by 5 percent in May and approximately 10 percent in June from the previous year. Offpeak demands in the Cal-ISO increased significantly during the summer, in large part to meet increased pumping demands for hydro power facilities, needed for peaking purposes both inside and outside of California. However, peak demand in the ISO area fell slightly, partially reflecting response to emergency declarations and actions.

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

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

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

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

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

- *Prices in the ISO spiked in May and June and average June prices reached record high levels.* While an ISO price cap of $750 existed during the early part of the summer, prices became highly volatile and the hourly price hit the cap on 3 days in June. Average June prices reached record levels of $120 in the PX.

- *Average prices were lower in July than in June, but total costs paid by purchasers in August were higher than in June.* Caps of $500 in July and $250 in August had a dampening effect on high hourly prices, but average prices in August rose to $166 in the PX after falling below June levels to $106 in July. The lower caps may have played a role in increasing exports in July and August.

- *Prices at other trading hubs in the West generally correlated with California prices, suggesting that opportunities to sell at high prices existed in these regions when California prices were high.* However, it is not yet clear how scarce supplies were in these regions or to what extent prices outside California were for California imports rather than consumption in other regions. While information for certain weeks in the West indicated supply was scarce, it was not possible to make an overall assessment on scarcity throughout the West without additional information.

- *Cost for fuel and environmental compliance (NOx credits) increased significantly in July and August.* Gas prices rose from approximately $2 per MMBtu early in the year to approximately $5 per MMBtu in August. Credits to comply with NOx standards rose from $6 per pound in May to $35 in August and $45 in September. Lowered caps in July and August reduced the ceiling for market prices while these fuel and environmental costs raised the "floor." As a result, prices traded over a narrow range.

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

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

Section 4 outlines the statutory and regulatory framework related to energy markets in the West. The report describes the roles and policies of the federal and state economic and environmental agencies in regulating electric utilities in California and the western states. It also discusses the restructuring efforts in California and the establishment of the California ISO and PX, as well as the creation of the California Electricity Oversight Board. Additionally, this section outlines requirements imposed on the California utilities by the California Public Utilities Commission (CPUC).

Section 5 discusses the issues that were raised as possibly causing the high prices of this summer. These fall into three general categories: (a) competitive market forces, (b) market design problems and (c) market power. The data clearly show that a general scarcity of power in the West and increased costs to produce power were factors causing these high prices. It is also clear that existing market rules exacerbated the situation and contributed to the high prices. The data also indicate some attempted exercise of market power, if the standard of bidding above marginal cost is used, and some actual market power effects, to the extent that prices, at least in June, were significantly above competitive levels. However, the data do not isolate specific exercises of market power or suggest that the exercise of market power was more important than other primary explanatory factors.

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

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

2. Supply and Demand Conditions

Supply and demand conditions throughout the West were tight much of the summer, with emergency conditions concentrated in California. The broad factors were hot weather, in some cases extreme hot weather, coupled with continued demand increases without corresponding increases in power production capability. The main findings of the report on demand and supply conditions are:

- *Overall demand increased significantly.* Driven by hot weather, load increases over previous years were most pronounced in May and June. Average summer demand in the California Independent System Operator (Cal-ISO) area increased 8 to 9 percent over the previous 2 years. Peak hour demand forecasts increased slightly over 1999, but actual hourly peaks fell slightly, reflecting in part the response to emergency declarations and actions. Offpeak demands increased significantly in July and August, in part to meet increased pumping demands and to conserve water stored at hydropower facilities, needed for peaking purposes both inside and outside the Cal-ISO area.

- *Exports from California increased significantly, with little overall change in the level of imports.* As a result, net import decreases averaging up to 3,000 megawatts (MW) needed to be offset by increases in generation internal to the ISO control area. The ability to increase imports was limited by hydro conditions in the Northwest, which actually declined in July and August, and tight load conditions in other western subregions. Weather conditions in the desert southwest were among the hottest on record. These conditions led to increased exports in July and August, corresponding to the decreases in the ISO price cap from $750 to $500 in July and to $250 in August.

- *Outages increased significantly.* Compared with 1999, outages in the Cal-ISO area increased as much as 2,900 MW. Planned outages in January through April were significantly lower in 2000 than in 1999. However, unplanned outages in May through August, particularly in July and August, were much higher in 2000 than in 1999.

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

- *Non-hydro generation resources throughout the West were more heavily utilized in 2000 than in 1999.* In 2000, non-hydro resources generated 15.1 percent more power in May and 24.9 percent more power in June, compared with 1999. Based on an analysis of WSCC capacity during the week of July 31 to August 4, little additional capacity appears to have been available at such peak times.

Section 2.A. provides background on supply and demand: the bulk power system in the West, distribution of resources and expectations for the summer of 2000 in the spring. Each of the main findings summarized above is discussed in Section 2.B.

A. Supply and Demand Background

1. Brief Description of Bulk Power System in the West

The Western Grid encompasses 1.8 million square miles within 14 western states, two Canadian Provinces, and a portion of Baja California Norte Mexico. Figure 2-1 illustrates the configuration of the Western Grid. The Western Interconnection transfer capability with other regions is limited to around 1,000 megawatts.

The Western Grid operates under the North American Electric Reliability Council (NERC) guidelines as administered by the regional reliability council: the Western Systems Coordinating Council (WSCC). The WSCC is divided into four reporting subregions and 30 load control areas. The subregions are shown in Table 2-1.

Table 2-1. Subregions in the WSCC

Subregion	States Comprised
AZ/NM/SNV (Arizona)	Arizona, most of New Mexico, the western part of Texas, southern Nevada, and a portion of southeastern California
CA/MX (California)	Most of California and the northern portion of Baja California, Mexico
NWPP (Northwest)	Washington, Oregon, Idaho and Utah, British Columbia and Alberta, and portions of Montana, Wyoming Nevada and California
RMPA (Rockies)	Colorado, eastern Wyoming, and portions of Western Nebraska and South Dakota

Within the California-Mexico subregion (California) of the WSCC is the California power grid, which carries bulk electricity to local utilities for distribution to their 27 million customers and transports significant amounts of power for other generation or local distribution entities in the region. The Cal-ISO assumed control of 75 percent of the California power grid (Cal-ISO grid) in 1998, consolidating the transmission systems of the three investor-owned utilities into one large system. The network comprises 21,000 circuit miles of power lines that deliver about 165 billion kilowatt-hours of electricity each year. Power plants connected to the Cal-ISO grid have a total capacity of approximately 45,000 megawatts.

2. Historical Load Growth and Resource Mix

Peak load in the WSCC has been steady over the last 17 years, as shown in Figure 2-2. Over this period, growth in peak summer demand was highest in the Arizona/New Mexico/Southern Nevada (Arizona) region, at an overall annual average of 7.9 percent, followed by California at 3.2 percent, the Rockies at 2.8 percent and the Northwest at 2.4 percent. Table 2-2 shows load growth for two recent 3-year periods. California and Northwest show large differences in growth rates between the two 3-year periods, while growth rate differences in the Rockies and Arizona are small. These variations can be driven by many factors, but two major ones include changes in weather patterns and increases in economic activity.

The WSCC region has approximately 160 gigawatts (GW) of generation capacity. From 1991 to 1998, an average of 1,197 megawatts (MW) were added per year, a growth rate of under 1 percent.[1] Current and planned (as of January 1, 2000) capacities by subregions are shown in Table 2-3. Planned capacities in this table represent all active plans and are adjusted for planned deratings and retirements of current capacity. Only small amounts of capacity were planned for 1999 and 2000 (only around 1 percent in each year.) Significant capacity additions have been planned for 2001 and 2002, but may be subject to cancellation depending on investors' perceptions of market and regulatory stability.

Figure 2-3 shows the wide variation in the types of generation resources across the WSCC region. The Northwest is dominated by hydropower (65% of capacity). The output of the many federally owned and operated hydropower facilities is marketed by the Bonneville Power Administration. The Rockies have largely coal generated resources (68%). Arizona has a large amount of coal capacity (41%); these coal resources are more expensive to produce than the coal resources in the Rockies, but still well below the cost of producing power from oil or natural gas sources. Many of the resources in California are oil and/or natural gas generation.

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1 Resource Data International, RDI Powerdat Information System, September 2000.

Figure 2-1. Western Power Grid

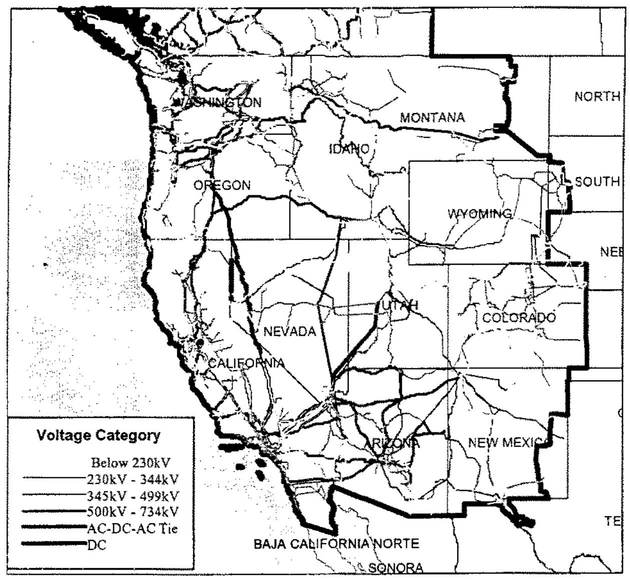


Table 2-2. Comparison of 3-Year Average Growth in Summer Peak, in the WSCC, 1998 and 1995

Subregions	Average Growth Percentage 1996 to 1998	Average Growth Percentage 1993 to 1995
Arizona	4.3	4.3
California	3.9	0.6
Northwest	3.4	0.8
Rockies	3.0	4.3

The pattern of imports and exports of power among the four subregions and Canada is to a large extent determined by the distribution and cost of generating resources. The Northwest and the Rockies subregions are significant exporting areas at peak times: the former based on the availability of hydropower capacity and the latter based primarily on coal-fired generation. California is the major importing subregion, both because its capacity is below its peak load, but also because this capacity is more expensive. The import and export patterns are generally seasonally based, with California importing in the summer and exporting to the Northwest in the winter. Table 2-4 shows annual trends in generation, imports and exports from 1990 to 1998. Steady increases in imports are shown into the California and Arizona subregions, with the increased exports coming largely from the Northwest. A particularly large increase in exports from the Northwest (and corresponding imports into California and Arizona) is shown for 1997 and 1998.

Table 2-3. Current and Planned Generation Capacity in the WSCC, as of January 1, 2000
(Megawatts)

		Planned Plants by Planned Online Year					
Subregion	**Current**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**
Arizona	24,562	132	1,919	4,885	4,055	0	500
California	52,709	620	2,505	3,110	1,594	0	255
Northwest	72,443	1,426	1,115	1,391	836	51	-67
Rockies	9,381	358	251	799	672	339	85
Total WSCC	159,095	2,536	5,790	10,185	7,157	390	743

Source: WSCC-Existing Generation and Significant Additions and Changes to System Facilities, 1999-2009, issued May 2000.

Notes: Planned capacity includes all active plans, with reductions for retirements. Northwest includes Canada.

Figure 2-2. Peak Summer Demand in WSCC

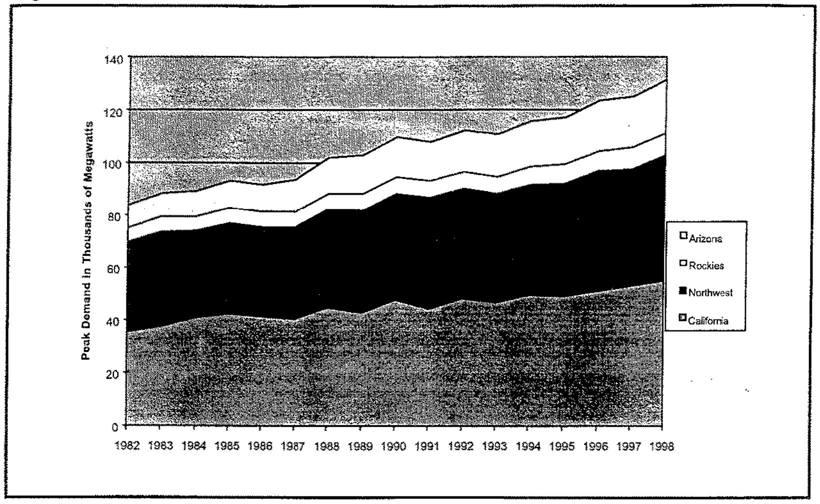


Figure 2-3. Capacity Resource Percentages by WSCC Subregions

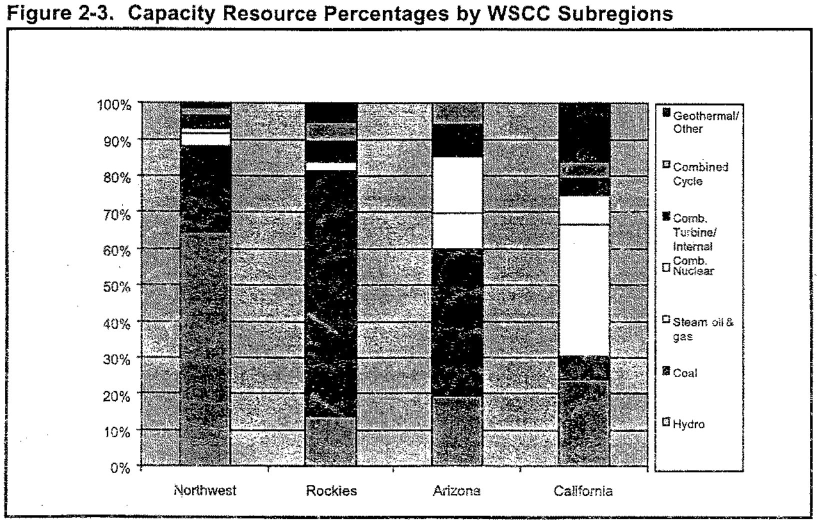


Table 2-4. Generation, Imports and Exports in WSCC, 1990 to 1998
(Thousand Megawatthours)

	1990	1991	1992	1993	1994	1995	1996	1997	1998
Internal Generation									
Arizona	66,852	72,811	72,998	77,373	76,091	79,271	76,035	77,467	94,155
California	208,350	199,435	195,099	215,474	221,911	230,660	225,384	218,720	205,246
Northwest	214,623	235,047	235,190	217,682	219,935	221,970	239,155	265,852	278,699
Rockies	43,315	42,141	42,603	42,997	43,505	44,166	45,844	48,187	52,431
Total WSCC	533,140	549,434	545,890	553,526	561,442	576,067	586,418	610,226	630,531
Imports									
Arizona	7,222	5,526	4,649	4,355	5,826	5,641	7,117	14,142	15,374
California	30,814	46,665	45,336	33,187	31,011	30,814	30,738	45,730	51,125
Northwest	11,278	8,115	9,465	17,204	21,274	19,009	11,069	17,098	12,711
Rockies	2,999	3,723	2,856	3,355	4,230	5,278	4,342	3,929	3,676
Exports									
Arizona	12,882	14,594	13,548	15,432	13,585	12,613	9,406	12,362	10,998
California	4,011	2,799	2,409	4,980	10,183	9,207	7,191	6,477	6,236
Northwest	19,769	30,445	29,729	19,104	23,510	21,406	30,156	52,442	66,526
Rockies	8,293	7,377	7,021	6,366	7,186	7,391	6,764	8,194	9,028

Source: NERC Electricity Supply and Demand 2000 Database (ES&D)

3. Spring Expectations for the Summer of 2000

The WSCC forecasts include a separate forecast for each of the four subregions and for the WSCC region as a whole. The subregion forecasts are required due to differences in demand, installed generation, and limitations in the western transmission grid. In its updated May forecast for the summer of 2000, the WSCC concluded that if normal temperatures were to prevail during the summer period, projected regional capacity margins and reliability should be adequate. It also stated that if higher than normal unplanned generator outages occur, an area experiences significantly higher than normal temperatures, or the loads in multiple areas peak simultaneously, portions of the region may need to issue public appeals for customers to reduce their electrical consumption or other measures may be necessary.

WSCC concluded that the southwest portion of WSCC (New Mexico, Arizona, southern Nevada, California, and Baja California, Mexico) might not have adequate resources to accommodate a widespread severe heat wave or higher than normal generating outages. Table 2-5 shows the WSCC projected total demand, resources and anticipated margins for the summer months for those portions of the WSCC region located wholly within the United States.

Table 2-5. WSCC-U.S. Forecasted Demand and Supply, Summer 2000
(Megawatts)

	May	June	July	August	September
Total Load	96,908	108,635	116,440	114,899	107,616
Total Resources	136,023	136,868	136,771	136,586	137,166
Unavailable	10,959	3,780	2,830	2,927	5,944
Net Resources	125,064	133,088	133,941	133,659	131,222
Net Imports and Exports	533	483	483	283	283
Margin MW	29,034	28,228	21,281	22,697	27,645
Margin %	30.4	27.0	19.0	20.5	26.8

The forecast for the summer from the California subregion is summarized in Table 2-6. The Cal-ISO also prepared a forecast containing two different weather assumptions, and consequently two different peak and net import forecasts (see Table 2-7). The WSCC and ISO forecasts agreed that exceptionally high temperatures could lead to a capacity shortage.

Table 2-6. WSCC-California Forecasted Demand and Supply, Summer 2000
(Megawatts)

	May	June	July	August	September
Total Load	38,906	47,457	52,057	51,487	47,978
Total Resources	54,516	54,497	54,497	54,497	54,497
Unavailable	1,718	118	0	0	1,656
Net Resources	52,578	54,379	54,497	54,497	52,841
Net Imports and Exports	-4,960	-5,605	-5,605	-5,602	-5,634
Margin MW	15,193	11,738	8,728	8,489	9,628
Margin %	39.1	26.3	17.7	17.4	21.3

Table 2-7. Projected Cal-ISO Peak Loads and Resources
(Megawatts)

Load Condition	Peak In-Area Load	Generation	Net Imports	Excess (+) or Deficiency (-)
Normal	46,250	38,000	8,400	150
High	48,940	38,000	7,000	-3,940

B. Summer 2000

This section presents the results of staff's examination of the performance of western markets during the summer of 2000, concentrating on the key findings from the study relating to supply and demand conditions. Much discussion and attention have been focused on the problems in California and its market, but review of the events of the summer needs to start with the overall western pattern of load and supply. Accordingly, this section starts with a review of western demand and its underlying determinants.

1. Demand Growth

Demand has been steadily growing in the West, particularly in areas driven by technology such as California and the Northwest. In addition, summer demand in 2000 was driven by extreme weather conditions throughout the West. Figure 2-4 summarizes the May through August 2000 temperature patterns in western regions. California is shown separately from the California/Nevada region. The figure shows the rank of the regional temperature over the last 106 years. It is clear from the figure that the Southwest, including Arizona, New Mexico, Utah and Colorado, was very hot for the entire summer. It is also clear that all areas were hot early in the summer, in May and June, when signs of high prices and price spikes first surfaced in California.

While May and June were extremely hot throughout the West, July and August show a mixed pattern, with moderate to below normal temperatures outside the Southwest in July and hotter than normal temperatures throughout the region in August, but falling short of the extreme hot weather of June. The weather pattern in June over the last 3 years is shown in Figure 2-5. Regardless of the absolute rank of the summer of 2000, it is easily seen that the summer marked a departure from the mild summers since 1998 when California began to implement restructuring. The wide geographic distribution of hot weather in June 2000 placed new stresses on the generation and transmission system throughout the West, taxing the ability of exporting areas to keep up with both internal and external demands.

Figure 2.4. Rank of Regional Temperatures: May to August 2000

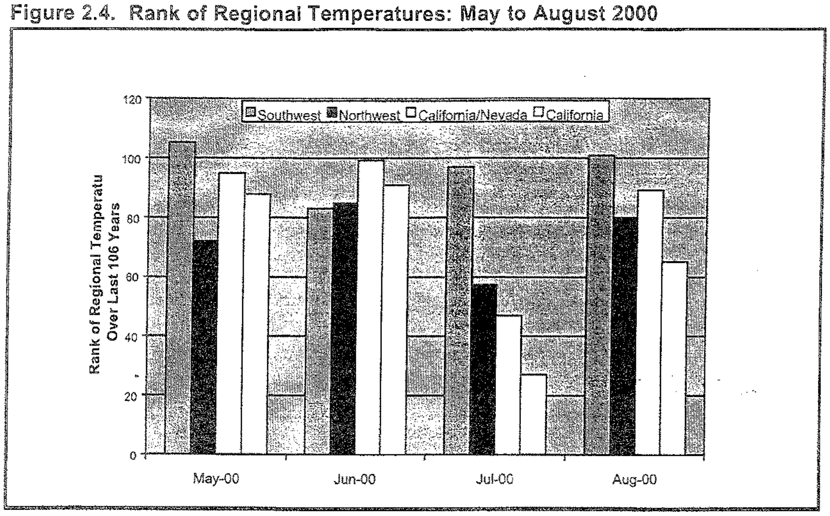
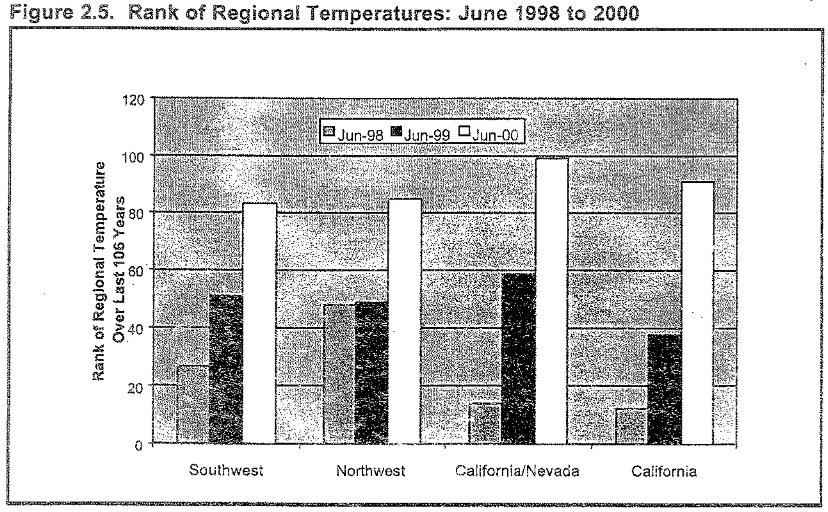


Figure 2.5. Rank of Regional Temperatures: June 1998 to 2000



Source: NOAA web site: @http://www.ncdc.noaa.gov/ol/climate/climateresearch.html

These weather patterns are reflected in the load growth statistics for western states in May and June, shown in Table 2-8, which compares loads in 2000 for May and June with corresponding loads in 1999. In June, overall load is estimated by EIA to have grown 13.7 percent in California and 7.3 percent in the West outside California. Heat-sensitive residential load grew even more: 23.8 percent in California and 9.0 percent outside California. States bordering California, Nevada and Arizona, experienced comparable or higher changes from 1999 to 2000: Arizona residential load grew 22.3 percent in June, and Nevada grew 27.2 percent.

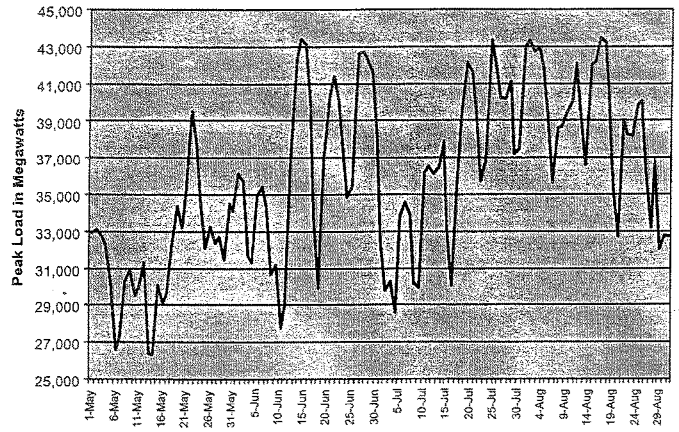
Table 2-8. Load Growth in the West, May and June 1999 to May and June 2000

(Thousand Megawatthours)

	All Sectors			Residential		
State	1999	2000	% Change 1999 to 2000	1999	2000	% Change 1999 to 2000
			May			
Arizona	4,421	5,247	18.7	1,415	1,928	36.3
Colorado	3,096	3,580	15.6	972	974	0.2
Idaho	1,730	1,787	3.3	483	431	-10.8
Montana	906	787	-13.1	298	241	-19.1
Nevada	2,125	2,518	18.5	583	786	34.8
New Mexico	1,549	1,542	-0.5	341	358	5.0
Utah	1,670	1,849	10.7	434	446	2.8
Wyoming	994	1,041	4.7	169	148	-12.4
Oregon	3,897	4,064	4.3	1,339	1,224	-8.6
Washington	7,768	7,061	-9.1	2,595	2,456	-5.4
West Outside California	28,156	29,476	4.7	8,629	8,992	4.2
California	17,626	18,649	5.8	5,194	5,625	8.3
			June			
Arizona	5,248	5,827	11.0	2,058	2,517	22.3
Colorado	3,130	3,823	22.1	949	1,060	11.7
Idaho	1,898	2,249	18.5	460	446	-3.0
Montana	626	825	31.8	262	247	-5.7
Nevada	2,475	2,730	10.3	850	1,081	27.2
New Mexico	1,554	1,601	3.0	373	414	11.0
Utah	1,952	1,979	1.4	528	533	0.9
Wyoming	1,037	1,039	0.2	139	145	4.3
Oregon	3,859	4,312	11.7	1,139	1,185	4.0
Washington	7,462	6,978	-6.5	2,233	2,171	-2.8
West Outside California	29,241	31,363	7.3	8,991	9,799	9.0
California	19,225	21,867	13.7	5,720	7,084	23.8

Source: Energy Information Administration, *Electric Power Monthly*, August and September 2000.

Figure 2-6. Cal-ISO Load Curve, May to August 2000



Turning to the Cal-ISO area, Figure 2-6 shows daily peak-hour load from May to August 2000. As the figure shows, peak load is volatile over a fairly wide range, sometimes swinging rapidly from under 30,000 MW to over 40,000 MW. Managing these fluctuations is a complex task under any circumstance, but it becomes even more difficult in a complex market environment in transition. Forecasting load then becomes particularly important for maintaining the reliability of the system.

Table 2-9 shows the average, day-ahead forecast and actual loads for the Cal-ISO area over the last three summers. These data confirm the main conclusions from the temperature and the state-level load data in Table 2-8. The Cal-ISO experienced much higher loads in May and June compared with previous years. July was much more moderate and August loads were higher but not as high relative to previous years as June loads. The percentage differences in actual average loads from previous years, shown in Figure 2-7, bear these conclusions out.

Figure 2-7 also shows that, on average, day-ahead forecasts and actual loads are close as one would expect. While examining average loads is instructive, peak load forecasting is central to reliable system operation. Accurate forecasting of peak loads is

Table 2-9. Cal-ISO Day-Ahead Forecast and Actual Average Loads, 1998 to 2000

	May	June	July	August	May-August
Forecasts					
1998	22,963	24,847	29,423	30,996	27,075
1999	24,276	26,736	29,022	29,113	27,291
2000	26,906	30,075	29,926	31,505	29,599
Actuals					
1998	22,960	24,852	29,122	30,691	26,923
1999	24,171	26,609	28,878	29,016	27,173
2000	26,883	29,981	29,461	31,104	29,352

essential for estimating peak supply requirements. The peak forecast and actual loads shown in Figure 2-8 indicate how difficult peak conditions and forecasting became in 2000. While May forecasts and actuals both tracked 1999 and 1998, the forecasts in 2000 began to deviate as the summer progressed. Forecasts consistently exceeded actual loads. In August, for example, forecasted loads increased over previous years (e.g., by 7.5 percent over 1999), but actual loads decreased (e.g., by 0.9 percent over 1999) .

Figure 2-7. Average Loads in the Cal-ISO, Day Ahead Forecast and Actual

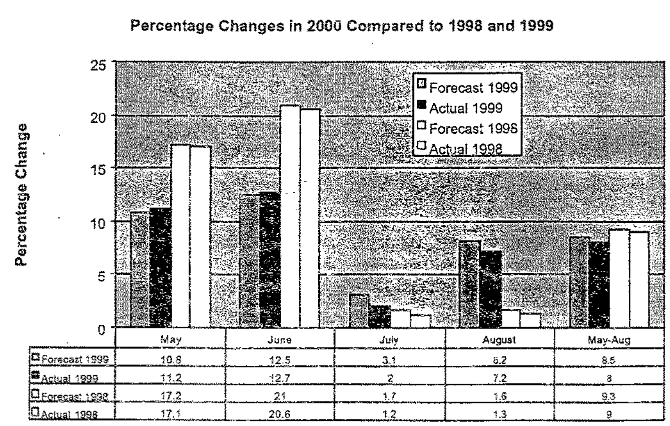
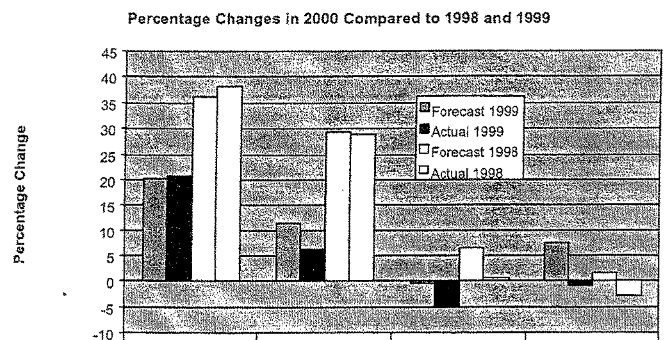


Figure 2-8. Peak Loads in the Cal-ISO, Day-Ahead Forecast and Actual



	May	June	July	August
Forecast 1999	20.3	11.4	-0.5	7.5
Actual 1999	20.8	6.2	-4.9	-0.9
Forecast 1998	36.2	29.3	6.4	1.6
Actual 1998	38.1	28.9	0.5	-2.8

Part of this deviation between forecast and actual loads can be attributed to the number of system emergencies that the Cal-ISO experienced in 2000, since during these emergencies interruptible customers must reduce loads and public appeals are made for voluntary load reduction. Cal-ISO issued 38 emergency notices over the summer, far more than in prior years. These actions are summarized in Table 2-10.

The discussion thus far has concerned overall average or peak loads, but the offpeak period (from 11:00 p.m. to 6:00 a.m.) also can be critical during the summer. This time is used to pump water at pumped storage hydropower facilities, so these facilities can be used to meet peak demands. These requirements create additional demand for energy to pump the water and can be important in years with high temperature and low water such as 2000. Other shifts in demand to offpeak can occur if customers can shift loads to avoid high onpeak energy costs. Table 2-11 shows how the average offpeak loads increased in 2000 compared with 1999.

Table 2-10. Electrical Emergencies Declared by the Cal-ISO (May-August)

Emergency Type	Action Taken	1998	1999	2000
Stage One: May be declared when operating reserves of less than 7 percent are unavoidable or exist in real time.	Utility customers are urged to reduce their use of electricity voluntarily to avoid more severe conditions	3	3	24
Stage Two: May be declared when operating reserves of less than 5 percent are unavoidable or exist in real time.	Voluntary interruption of services to select customers is required to avoid more severe conditions. These customers receive a reduced rate electrical service as compensation for their willingness to be curtailed	3	0	14
Stage Three: May be declared when it is clear that operating reserves of less than one-and-a-half percent are unavoidable or exist in real time.	Utility customers are advised that involuntary interruptions of service have begun and will continue until the emergency has passed.	0	0	0
Total		6	3	38

Table 2-11. Offpeak Loads in the Cal-ISO Area
(Megawatts)

	Average Hourly Loads		Maximum Hourly Loads	
	1999	2000	1999	2000
May	20,036	21,609	25,475	29,043
June	21,245	23,567	30,096	32,439
July	23,007	23,318	33,702	31,848
August	23,035	24,268	31,132	32,946
May-August	21,835	23,187	33,702	32,946

2. Increased Exports from California

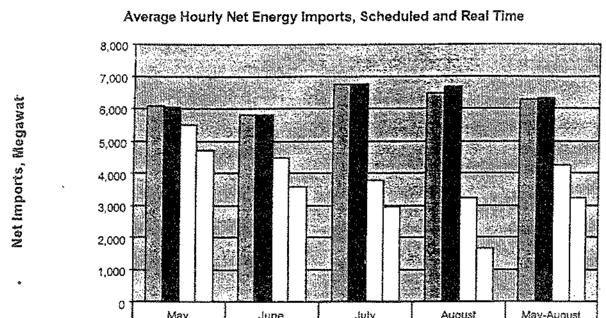
Increased exports from California are a key factor in understanding western supply in the summer of 2000. These increases require offsetting imports to meet any given level of load within the Cal-ISO area. Net imports, the total imports reduced by the amount of exports, were significantly lower in 2000 compared with 1999. Figure 2-9 shows both scheduled (through the hour ahead) and actual imports in real time in 1999 and 2000. Net imports fell dramatically throughout the summer, in both scheduled and real-time categories. The biggest differences between 1999 and 2000 occurred in the scheduled net imports in August, when scheduled net imports were 6,502 megawatts per hour in 1999 and 1,673 in

2000. An additional 1,542 megawatts of imports appeared in real time, reducing the difference from last year.

The decrease in net imports is generally attributable to increases in exports, not decreases in imports, as Figure 2-10 clearly shows. In 2000, imports remained virtually unchanged throughout the summer. In 1999, some increases in imports occurred, but the leading fact shown in Figure 2-10 is the increase in exports for each month from May to August 2000, from an hourly average of 1,831 megawatts in May to 4,851 megawatts in August, an increase of 3,020 megawatts. Comparable export increases in 1999 occurred, but they were small. Compared with August of 1999, August 2000 exports averaged 3,136 megawatts above the August 1999 level. This period of increased exports corresponds to the periods in July and August when the price cap in the ISO was reduced from \$750 to \$500 and then to \$250. This correspondence does not necessarily show price caps caused increased exports; however, other things being equal, lower price caps may provide for greater profits from exports if conditions outside California lead to high prices and create greater opportunity costs.

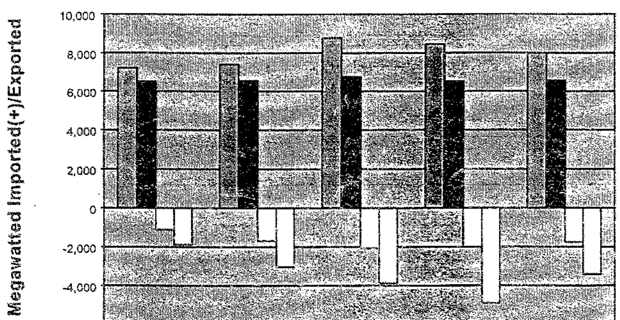
Although most exports are from the SP15 zone in southern California, increases were not limited to SP15 (see Table 2-12). SP15 experienced an increase in offpeak exports from May to August of 1,385 megawatts over a May quantity of 1,038; the NP15 zone in northern California had an increase of 766 megawatts over the much smaller base of 223 megawatts in May. Exports from the NP15 zone are typically offpeak and may be related to pumping at hydropower facilities or maintaining storage levels at conventional hydro facilities to conserve water, particularly later in the summer. Offpeak exports followed the same pattern as overall exports, as the daily graph of offpeak exports in Figure 2-11 shows, when compared to the overall pattern of increases from May through August.

Figure 2-9. Net Summer Imports into Cal-ISO, 1999 and 2000



	May	June	July	August	May-August
Scheduled 1999	6107	5804	6748	6502	6294
Real Time 1999	6050	5812	6740	6664	6321
Real Time 2000	5489	4501	3770	3215	4241
Scheduled 2000	4704	3598	2960	1673	3231

Figure 2-10. Imports and Exports, Average Hourly, 1999 and 2000

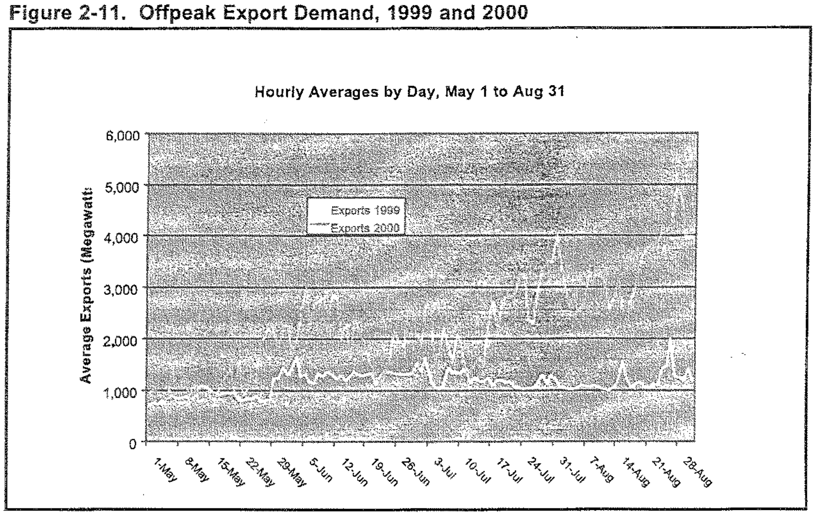


	May	June	July	August	May-August
Imports 1999	7214	7471	8784	8489	7994
Imports 2000	6534	6595	6807	6524	6615
Exports 1999	-1107	-1667	-2036	-1987	-1700
Exports 2000	-1831	-2995	-3846	-4851	-3384

Table 2-12. Summary of California Exports and Imports by Zone

	May	June	July	August	May-August
SP15 Zone					
Imports 1999	4,441	4,222	5,426	5,645	4,939
Imports 2000	4,590	4,841	4,547	4,790	4,691
Exports 1999	-859	-1,310	-1,171	-1,088	-1,105
Exports 2000	-1,038	-1,758	-1,828	-2,423	-1,762
Net Imports 1999	3,582	2,912	4,255	4,557	3,834
Net Imports 2000	3,552	3,083	2,719	2,368	2,929
Real Time 1999	3,554	2,811	4,132	4,533	3,765
Real Time 2000	3,784	3,169	2,846	2,447	3,061
NP15 Zone					
Imports 1999	1,561	2,147	2,408	2,090	2,051
Imports 2000	1,074	1,210	1,113	1,182	1,144
Exports 1999	-61	-7	-34	-91	-49
Exports 2000	-223	-385	-580	-989	-546
Net Imports 1999	1,500	2,140	2,374	1,999	2,002
Net Imports 2000	851	825	533	193	598
Real Time 1999	1,444	2,123	2,335	2,029	1,981
Real Time 2000	1,187	1,177	770	717	961

Figure 2-11. Offpeak Export Demand, 1999 and 2000

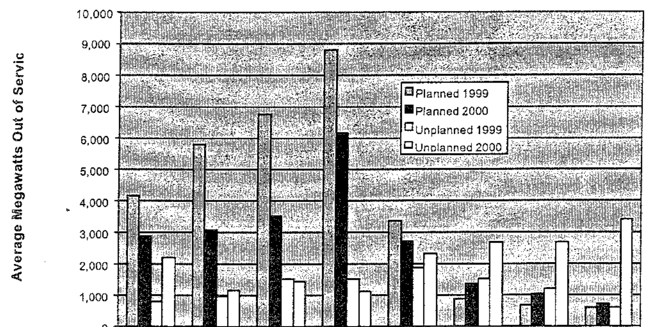


3. Increased Plant Outages

An increased level of unplanned outages at generating plants is another key factor limiting available generation supply in 2000. California has a large number of natural gas fired plants. Natural gas steam plants make up most of this capacity and constitute 36 percent of the total generating capacity in the state. These steam plants are old and hence prone to outages; 82 percent of these plants are over 30 years old, and 37 percent are over 40 years old.[2] Outages in 1999 and 2000 are shown in Figure 2-12 for January through August. The level of unplanned outages increased through August compared with last year; there were 3,391 megawatts out of service (hourly average megawatts out during the month) in August 2000 compared with 604 megawatts in August 1999. This difference of 2,787 megawatts has a clear effect on supply at peak times, even though the level as a percentage of the 45,000 megawatts of installed capacity may not be out of the normal range for comparable plants. It is not clear exactly why these plants went out of service. Detailed analysis of specific causes was not possible for this investigation. Review of cited reasons by plant operators in available records showed the normal pattern of explanations for a peak summer period, such as tube leaks at steam facilities and other

[2] RDI Powerdat, September 2000.

Figure 2-12. Comparison of Average Megawatts Out of Service in the Cal-ISO Planned and Unplanned, 1999 and 2000



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
Planned 1999	4145	5791	6735	8774	3361	882	660	586
Planned 2000	2886	3083	3531	6140	2702	1349	1039	724
Unplanned 1999	801	957	1506	1508	1877	1516	1204	604
Unplanned 2000	2187	1158	1420	1124	2331	2688	2666	3391

Month

similar causes, but it was not possible to confirm the accuracy of such judgments. Most outages were for short durations (see Table 2-13), with 59 percent occurring for one day or less, so a detailed analysis would be very time consuming.

There are several potential explanations for the increased level of outages. Figure 2-12 indicates a much lower level of planned maintenance in January through April 2000 compared with January through April 1999, so one possibility is that fewer resources are being devoted to planned maintenance. Lack of planned maintenance could be particularly important for older facilities. Given the short duration of outages, the increased number could reflect attempts to fix small problems in preparation for high load conditions. New owners, for example, could be attempting to maximize the availability of their facilities at peak times when the price is high. A final possibility is just the opposite: owners could be withholding by taking plants out of service at critical times to drive up prices. The difficulty here is twofold. First, the same general pattern of events permits completely contrary explanations in terms of efficient behavior. Second, specific instances alone may not serve to prove a general pattern, will be hard to substantiate, and cannot be fairly attributed to individual participants without further investigation of these specific cases.

Table 2-13. Percent of Unplanned Outages by Duration, Cal-ISO Units, 1999 and 2000

Duration	1999	2000
1 day or less	65.0	59.0
1 to 2 days	69.9	67.6
Less than 2 weeks	85.7	91.7

Some information can be gained by examining the level of outages and their timing. By examining the correlation between outage levels and price increases in the PX, one can roughly measure the association of the two series. These correlations are presented in Table 2-14, which shows the correlation of outage levels and PX prices, as a function of when the outage occurs. For example, the correlations in the category "Day of price increase" is measured between the outages on a particular day and the PX price on that day for deliveries on the following day. The category "1 Day before price increase" measures the correlation based on the level of outages on the day before the price is determined in the PX, and so on.

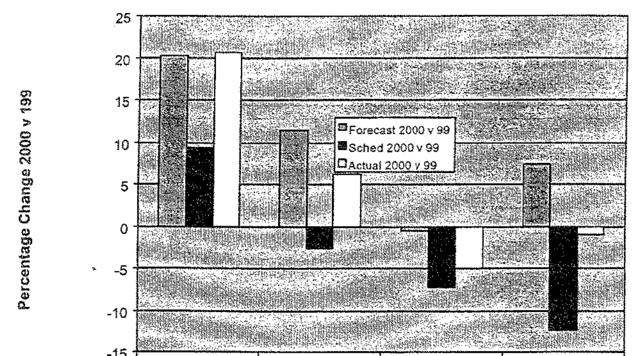
Table 2-14. Correlation of Outages with the PX UMCP, May to August 2000

Outage Occurs	Correlation
2 days before price increase	0.38
1 day before price increase	0.50
Day of price increase	0.46
1 day after price increase	0.40

The correlations show an association between outage levels and price increases, which is not surprising in itself. Outage levels would be expected to increase when prices are high, simply because loads increase and less reliable facilities are pressed into service under conditions of stress. The data also indicate, however, that the correlation is highest when the outages occur one day before the price increase. As noted above, facts such as these can be explained in a number of ways, but they do suggest that there may be more to the explanation than a simple physical response to running generating plants at higher levels under high load and price conditions.

4. Scheduling of Supply and Demand in California

Figure 2-13. Percentage Change from 1999 in Year 2000 Peak Forecast Scheduled and Actual Loads



	May	June	July	August
Forecast 2000 v 99	20.3	11.4	-0.5	7.5
Sched 2000 v 99	9.4	-2.5	-7.2	-12.3
Actual 2000 v 99	20.8	6.2	-4.9	-0.9

California day-ahead and hour-ahead markets saw a marked migration of supply and demand to real time markets and exports. Many of the imports were not scheduled and arrived in real time. A similar pattern for loads is shown in Figure 2-13, which shows the degree of underscheduling relative to day-ahead markets faced by the Cal-ISO. Figure 2-13 shows the change in underscheduling from 1999, as well as the amounts forecast and the actual results. As seen from the figure, in June and August, forecasts of load were much higher than in 1999, but scheduled load was much lower. The result is that the Cal-ISO is forced to purchase supplies in order to be able to meet load in real time. It can do this either by buying more replacement reserve or going out of market for real-time energy when insufficient generation is scheduled to meet final hourly forecast quantities. The Cal-ISO pursued both of these approaches in 2000.

The problem of underscheduling is not new in 2000, as can be seen in Figure 2-14, which examines day-ahead underscheduling. What has changed, however, is the level of load at which underscheduling occurs. In Figure 2-14, which shows the detailed pattern of

Figure 2-14. Scatter Diagram of Underscheduling, PX Day-Ahead Market

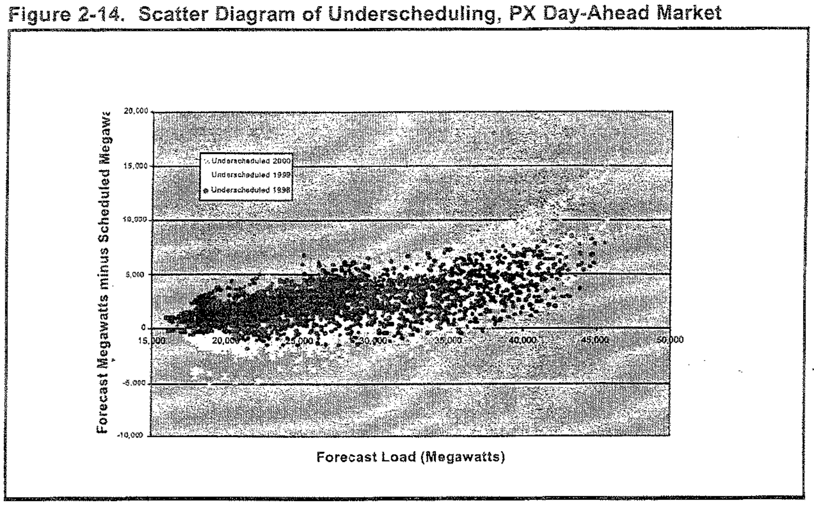
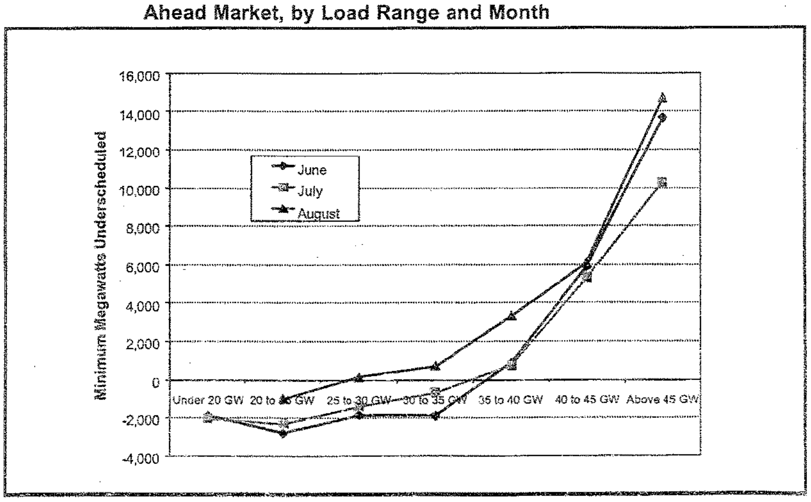


Figure 2-15. Underscheduling: Minimum Megawatts Underscheduled in PX Day-Ahead Market, by Load Range and Month



underscheduling as a function of load levels in 1998, 1999 and 2000, the observations for 2000 stretch out above the observations for 1998 and 1999 whenever the load grows above 35,000 megawatts. It also appears as if the load levels where underscheduling begins were lower in August than in June or July. Figure 2-15 shows the minimum underscheduling within load ranges. The minimum is the smallest difference between the forecasted load (day ahead) and the amount of load scheduled day ahead, for all hours when load fell within the range. This number will be negative if more supply/load is scheduled than forecast (overscheduling), and positive if less load/supply is scheduled (underscheduled.) Underscheduling normally increases as load increases, so that when load reaches a certain level, underscheduling always occurs and the minimum underscheduling will be positive. In August, the graph shows that underscheduling always occurred when the load was above 25,000 to 30,000 megawatts. The graph shows that underscheduling began to occur at lower and lower load levels from June through August, indicating that the problem of underscheduling became greater through the summer.

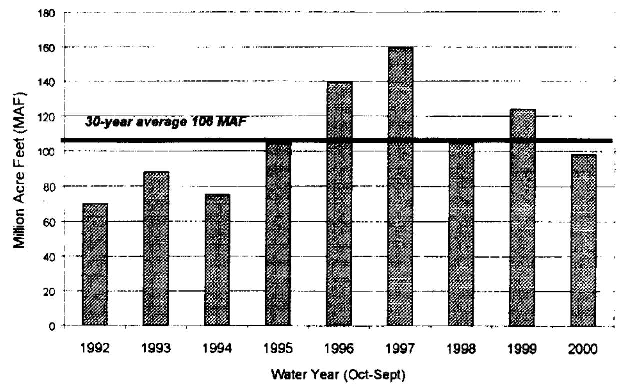
5. Generation Capacity Availability and Utilization

Previous sections have discussed factors contributing to limiting supplies of generation capacity in California and the western states generally. These factors bear on the reasons for any scarcity of available generation capacity. In this section, we review the evidence available to this investigation to assess the degree of that scarcity. We first review the role of hydropower in the supply of power in the West, and note the impact of hydropower availability on generation in May and June. Next we describe the availability of generation in the WSCC for a key summer week when California experienced several emergency periods and made a number of out of market calls for emergency imports of energy. Finally we look in greater detail at the availability of generation within the Cal-ISO during one hour of that week.

Hydropower Availability

Hydropower resources are central to the western resource mix. Although most regions depend on hydropower to some degree, the presence of such a large proportion of hydropower resources in the West introduces operational complexities not present in power systems in other regions. The capacity to produce power from hydro facilities depends on the availability of water, which in turn is heavily dependent on the amount of water run-off in the spring. Adding to these limitations are environmental restrictions that determine the amount of water that must be "spilled," that is, the amount required to pass

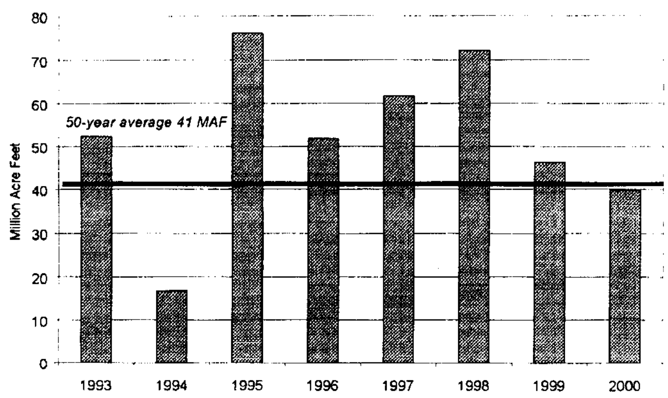
Figure 2-16 Volumes of Run-Off at the Dalles, January to July



Source: Bonneville Power Administration, web page http:\www bpa gov

over a dam or through a generating facility without going through the turbines and generating electricity. Because these types of restrictions vary with time, and in order to put the water to its highest-valued use, the dispatch of hydropower needs to carefully balance current and future values to optimize the use of the underlying resources. As a result of these factors, the actual physical capability of a generating unit is often not the element limiting the ability of a hydropower facility to provide power to the grid.

Figure 2-17. Volumes of Run-Off, California Statewide Total, October to July



Source: California Department of Water Resources, web page: http:\cdec.water.ca.gov

These limitations played a large role in the availability of hydropower in the summer of 2000. The volume of spring run-off was the lowest in several years in the Northwest, as shown in Figure 2-16. In California, the run-off fell below the 50-year average after 5 years of higher than normal flows (see Figure 2-17.) The impact of low water levels was seen in dramatically reduced generation from hydropower in May and June 2000 compared with 1999. Table 2-15 shows how extensive the shortfall in generation was: outside California, June 2000 generation from hydropower was 23.2 percent below June 1999 levels.

With reduced hydropower generation and increased load, the West needed much more generation from thermal and other non-hydropower resources. Generation from non-hydro resources increased by 15.1 percent in May and 24.9 percent in June (Figure 2-18).

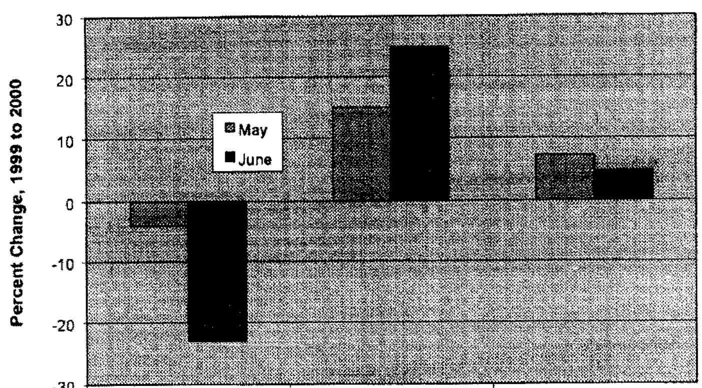
Table 2-15. Hydroelectric Generation in the West, 1999 to 2000
(Thousand Megawatthours)

	May			June		
State	1999	2000	% Change 1999 to 2000	1999	2000	% Change 1999 to 2000
Arizona	1,005	1,051	4.6	937	654	-30.2
Colorado	166	163	-1.8	161	178	10.6
Idaho	1,262	814	-35.5	1,201	939	-21.8
Montana	1,057	564	-46.6	1,328	757	-43.0
Nevada	279	294	5.4	254	208	-18.1
New Mexico	27	21	-22.2	31	24	-22.6
Utah	156	105	-32.7	160	80	-50.0
Wyoming	173	96	-44.5	205	127	-38.0
Oregon	3,999	3,576	-10.6	4,277	2,853	-33.3
Washington	8,087	8,131	0.5	8,131	6,988	-14.1
West Outside California	16,211	14,815	-8.6	16,685	12,808	-23.2

WSCC Capacity and Generation, July 31 to August 4, 2000

Aggregate monthly totals suggest that power supplies were often tight during the summer, but they do not provide very specific evidence about whether overall western supplies were scarce when California experienced emergency conditions and required emergency imports to prevent the loss of firm load. The week of July 31 to August 4 was such a period in California. The Cal-ISO had emergency conditions each day during that week and had a high number of out of market calls for power from external sources. To determine what other supplies were available in the West, each control area in the WSCC was asked to provide information on loads, generating capacities and generation for hour 16 on each day. From this information, it was possible to determine the percentage of capacity in the West available and used for generating electricity. The results are shown in Table 2-16.

Figure 2-18. Percent Change in MWh Generated in WSCC, 1999 to 2000



	Hydro	Non-hydro	All Sources
May	-4	15.1	7.3
June	-22.9	24.9	4.8

The first line in Table 2-16 shows the percent of projected capacity that was unavailable. This percentage is approximately equal to the forced outage rate, because the projected August capacity included reductions for any planned outages.[3] These percentages range from 4.4 to 5.4. Given the way hydropower resources are used, some hydropower capacity that was not forced out may have been available, but not placed online for generating power due to environment and other limitations on its use for power generation, discussed above. For this reason, a separate category was used for resources available but not on line. As shown in Table 2-16, this percentage varied from 3.6 to 6.2 during the week.

[3]The forced outage rate depends on how the category, "capacity online but not generating" was treated in the projected August capacity, and could be higher if these capacities were not included in the projected amounts.

Table 2-16. Summary of WSCC Capacity Availability During the Week July 31 to August 4, 2000

	31-Jul	1-Aug	2-Aug	3-Aug	4-Aug
	Percentages				
Projected August Capacity Unavailable	4.8	5.0	5.0	4.4	4.7
Capacity Available but Not Online	4.3	4.7	3.6	4.7	6.2
Available Capacity Online but Not Generating	11.0	9.5	12.0	11.0	10.1
Online Hydro not Generating	17.6	16.0	20.1	17.2	17.6
Online Non-Hydro Not Generating	6.6	5.0	6.4	6.8	4.8
Projected August Generating Capability=155,283 MW.					

Finally, the remaining capacity after the reductions discussed in the last paragraph will be online for use either to generate electricity or to provide reserves. The percentages of total online capacity not generating output vary from 9.5 to 12.0 percent. For non-hydropower resources, these percentages are much lower than for hydropower resources: from 4.8 to 6.8 percent of online capacity. Hydropower resource percentages are higher, from 16.0 to 20.1 percent, but these resources may not be available for export outside the local control area, or may be available only for short periods.

These data show that online supplies of non-hydropower resources were very limited during the week of July 31 to August 4, not more than 6.8 percent, and do not suggest that additional online hydropower was likely to be available for export to California.

Capacity Utilization at the Cal-ISO on August 4

Further specific information on the use of resources in California is provided in Table 2-17, which shows the use of resources by category of resource at hour 16 on August 4. The table shows high utilization of all resources except hydro and must take resources. The percentage of hydro resources not generating was 26.0 percent, the percentage of non-nuclear must take resources not generating was 30.9 percent. The hydropower resources may be subject to the types of limitations discussed above, and the percentages shown are only slightly higher than those in the overall statistics for the West discussed above. Thermal must-take resources include a large number of qualifying facilities, which includes capacity used for other purposes, such as internal uses or steam generation, so these resources may be used for alternate purposes. Discussions with Cal-ISO staff confirmed that these resources are generally limited by the quantity of energy available for bid, rather than by the total physically installed capacity. For all remaining resources combined (coal, nuclear, and other thermal categories,) only 2.7 percent were not scheduled or bid. One category where the owner of the facility has the discretion to bid or schedule the unit without bidding, the "Other Thermal (excluding RMR)" category, shows a higher percentage unscheduled or not bid than others, 8.6 percent. This quantity may represent owners holding back capacity to use if other scheduled units have outages, but it is not clear whether this is the reason or not. In any case, this quantity is a small amount of the total capacity neither scheduled nor bid, and does not suggest a large amount of withholding, regardless of the intent underlying the failure to schedule the capacity.

Table 2-17. Summary of Capacity Available and Energy Supplied in the Cal-ISO at Hour 16 on August 4, 2000

	Resource Category						
	Coal	Hydro	Nuclear	Other Thermal (Excluding RMR)	Reliability Must Run (RMR)	Must Take	All Categories
Total Capacity	1,540	12,117	4,414	5,533	14,175	8,579	46,358
Capacity Unavailable for Scheduling	790	26		572	1,889		3,277
Net Available	750	12,091	4,414	4,962	12,286	8,579	43,081
Capacity Scheduled/Bid	680	8,952	4,347	4,533	12,241	5,927	36,680
Capacity Not Scheduled or Bid	70	3,138	67	429	45	2,652	6,401
Percent Not Scheduled or Bid vs. Net Available	9.3	26.0	1.5	8.6	0.4	30.9	14.9

For the peak hour shown in Table 2-17, there does not appear to be a significant concern about resources not used. It is possible that resources are fully used at peak times when prices are high, but resources that are economic at other times are held off the market in an attempt to drive up prices. Further work would be necessary to study other hours to examine whether patterns vary at other times. This work could not be conducted within the time frame of the present investigation.

6. Transmission Congestion

Transmission patterns on California paths during May through August shifted from 1999 to 2000. Table 2-18 shows the percent of hours when transmission congestion occurred on major California paths in 1999 and 2000. In 1999 during peak hours, there was a lot of congestion on paths into California from the Northwest. The California Oregon intertie (COI) and the DC tie (NOB) were both congested a substantial portion of the time, as seen in Table 2-18. In 2000, much of this congestion was not present, due in part to the reductions in net imports, but a greater amount of congestion occurred on the major paths within California, Path 15 and Path 16.

Offpeak periods saw shifts as well. Congestion arising from imports from the Northwest and the Southwest virtually disappeared, but export congestion, mainly on paths from south to north, began to be important. These flows from south to north became more prominent in July and August. For example, NOB was congested for exports (south to north) for 40 percent of the offpeak hours and Path 15 south to north was congested 88 percent of the time during offpeak hours.

Table 2-18. Percentage of Time Major California Transmission Paths Congested, May through August, 1999 and 2000

Transmission Path	1999	2000	Difference (2000 minus 1999)
Onpeak Congestion			
Imports over Cal-Oregon Intertie (COI)	36.1%	0.3%	-35.8%
Imports from Oregon over DC Tie (NOB)	17.6%	8.0%	-9.6%
North to South on Path 15	1.0%	7.9%	6.9%
North to South on Path 26	0.0%	29.2%	29.2%
Offpeak Congestion			
Imports over Cal-Oregon Intertie (COI)	21.9%	0.0%	-21.9%
Imports from Southwest over Eldorado Path	21.0%	3.0%	-18.0%
Exports Oregon over DC Tie (NOB)	0.2%	13.5%	13.3%
South to North on Path 15	28.1%	49.6%	21.5%

3. Prices and Costs

Wholesale power prices were high throughout the West in the summer of 2000, but their implications for consumers were felt most acutely in the San Diego area of California. Because supplies were tight and prices were high throughout the West, recourse to imports could not relieve pressure on California prices when loads rose. The principal findings of the report on western prices and costs during the summer of 2000 are:

- *Prices in the Cal-ISO spiked in May and June and average June prices reached record high levels.* With an ISO price cap of $750 for the first time during the summer, prices became highly volatile and the hourly price hit the $750 cap on 3 days in June. Average June prices reached record levels of $120 in the PX in June.

- *Average hourly prices were lower in July than in June, but August prices were higher than June prices.* Caps of $500 in July and $250 in August had a dampening effect on high hourly prices, but average prices in August rose to $166 in the PX after falling below June levels to $106 in July. The lower price caps may have played a role in increasing exports in July and August.

- *Prices at other hubs in the West were highly correlated with California prices,* suggesting that opportunities to sell at high prices existed in these regions when California prices were high. However, it is not yet clear how scarce supplies were in these regions. Nor is it clear to what extent prices outside California were based on importing power into California rather than consuming it in other regions. Information from other regions in the West for the week of July 31 to August 4 suggests that supplies were in fact scarce, but it is not possible to assess the overall level of scarcity in the West throughout the summer without additional information.

- *Costs for fuel and environmental (NOx) compliance increased significantly in July and August.* Gas prices rose from around $2 per MMBtu early in the year to around $5 in August and the cost of credits for complying with the NOx standards rose from around $6 per pound in May to $35 in August and $45 in September. Lowered price caps in July and August reduced the ceiling on market prices while, at the same time, these fuel and environmental costs raised the floor. As a result, prices traded over a narrower range. Offpeak prices tracked upward with increases in offpeak demand while exports reduced available supply and outages increased during these months.

- *Prices in some hours appear to be above those that would have prevailed in a competitive short-term (hourly) market, if the competitive prices were determined from short-term marginal costs.* A Market Surveillance Committee (MSC) analysis indicates June prices were significantly above competitive levels using a simulation approach to defining the competitive price, but results are not available for July or August.[1]

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

These results are discussed in three subsections. The first subsection discusses prices in western markets and California, addressing the first three points above. The next subsection discusses the relationships between costs and prices, including input costs such as natural gas prices and environmental compliance, and relates these to the prices observed in western markets and markets at the California PX and ISO. The final section discusses bidding in PX and selected ISO markets.

A. Prices

During the summer of 2000, most of the Western Interconnection experienced unusually hot temperatures which triggered several price increases throughout the region. The volatile wholesale prices that plagued the Pacific Northwest caused some aluminum plants, pulp mills, cold storage facilities and mines to layoff workers and curtail production. With respect to California, the price increases that occurred in May and June were largely caused by unusually high temperatures coupled with robust economic growth that led to record high growth in electric loads. Prices in July were slightly lower than the previous month partly due to the California ISO (Cal-ISO) lowering its price cap from $750/MWh to $500/MWh effective July 1, 2000. However, in August, prices increased significantly higher than July even though the price cap was lowered again from $500 to $250 per megawatthour.

[1] "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," Market Surveillance Committee of the California ISO, September 6, 2000.

Major California Market Players

IOUs. The three major investor-owned utilities (also known as Utility Distribution Companies) in California are PG&E, SDG&E and SoCal Edison. The IOUs must buy from and sell all of their generation through the California PX until the end of the transition period in March 2002, or until they have recovered their competitive transition charges.

Non-Utility Generators. Generators provide energy and ancillary services either through the CalPX market or by contracting directly with buyers for ancillary services. Generation owned by the three IOUs comprised more than 90 percent of the market share during the CalPX's first months of operation. Between the first and second years of operation the IOUs divested generation units totaling 17,863MW, resulting in a share of 71 percent for the IOUs and 11 percent for the non-utility generators.

Federal Owners. Much of the hydropower is federally owned, with a large portion held by the Bonneville Power Authority (BPA.) Since California is so dependent on the availability of external resources, these owners can have a large impact on the California market as well as the rest of WSCC.

Municipal and other Public Owners. Municipals, cooperatives and other public entities control a significant portion of transmission and load in addition to generation. This ownership means that a significant portion of the transmission system in California is not under the direct control of the Cal-ISO.

Power Marketers. Market participants buy and sell energy in the Cal PX and Cal-ISO and also transact in bilateral markets. Many power marketers operating in California markets also own

The following discussion provides an overview of the market, including: market participants, ownership and market structure, trading patterns, pricing points, risk management and recent price trends in western markets.

1. Market Players and Ownership

The Western Interconnection has an active wholesale market, comprised of a diverse group of market participants. Market players in the West fall into the general categories found in other regions, with some key differences, particularly the large role played by publicly owned hydropower resources.

The shares of capacity by class of ownership for each subregion are shown in Table 3-1. In the Rocky Mountain and Arizona-New Mexico-S. Nevada regions, generation capacity is dominated by utilities. In the Northwest, federal entities are the largest generation owners. The largest share of generation capacity in California is held by non-utility owners, as a result of the state's generation divestiture.

Table 3-1. Ownership of Plants in the WSCC by Class of Owner
(Megawatts)

			WSCC Subregion			
Owner Class	Arizona	California	Northwest-US	Northwest-Can	Rockies	Grand Total
IOU	12,292	10,088	16,019	13	4,699	43,110
NON-UTILITY	2,154	25,439	4,698	951	1,004	35,084
FEDERAL	4,278	2,083	22,050		1,026	29,437
CANADIAN				20,062		20,062
PUBLIC AUTH	4,473	4,346	6,553		831	16,203
MUNI	1,271	7,304	4,986		1,234	14,796
COOP-GEN	795		564		1,863	3,221
MEXICAN		1,506				1,506
All Other	383	1,915	236	543	19	3,192
Total All Classes	25,646	52,682	55,106	21,569	10,674	166,611

Source: RDI Powerdat, August 2000.

As shown in Table 3-1, ownership of generation in the WSCC is divided among IOUs, non-utilities, and federal, public and municipal utilities. IOUs are the largest class of owner in the WSCC (26%) with non-utilities holding the second largest share (21%). In California, however, non-utilities hold more than 50 percent of the generation assets. This is a significant change from the period before the enactment of California restructuring legislation, and is a direct consequence of the forced divestiture of most of the IOU generating capacity. Municipals also hold a larger share (14%) of the generation capacity in California than in the WSCC as a whole (9%). Prior to the divestiture by the IOUs, generation capacity in California was more highly concentrated. In 1994, PG&E owned 49 percent of the state's generation, SCE owned 44 percent and SDG&E owned 7 percent. After divestiture, in 1999, the total owned by the three IOUs was 43 percent of the generation capacity in the state, with the other 57 percent divided among several new generation owners.

2. Trading Patterns and Hubs

While energy is traded at many locations, prices are reported at hubs where significant wholesale or bilateral activity occurs either for ultimate delivery to load in that area or as a convenient selling/delivery point for resale elsewhere.

Trading patterns and prices in western markets are driven to a large degree by the geographic placement of resources. With a heavy reliance on hydroelectric power as its dominant generation resource, the Pacific Northwest has typically provided the cheapest power in the West. Because of the importance of hydroelectric power to the region, the amount of rainfall and snowmelt in the area tends to have a significant impact on the market.

Inexpensive power also originates in the Rocky Mountains and the Southwest, where coal-fired generation is a large contributor to the generation mix. Because many of the generation resources in California are oil- and gas-fired, power generated there tends to be more expensive.

Western Market Trading Hubs

Palo Verde (PV) is the nuclear plant switchyard in southwestern Arizona of that name. This hub is a key selling point for wholesale sales into the Desert Southwest and southern California. It is accessible through several 500 kV lines. NYMEX has a futures contract for this hub.

COB (California Oregon Border) is the location for deliveries at the Captain Jack and Malin substations in southern Oregon, immediately north of the California border. Several 500 kV lines have interties there. This is often a proxy for sales into northern California in addition to sales into the Pacific Northwest. NYMEX has a futures contract for this hub.

Mid-Columbia (Mid-C) is a delivery hub at ties for a number of dams on the Columbia River. A NYMEX futures contract at Mid-C began trading on September 15, 2000.

Mead is the delivery point for a number of transmission lines outside of Las Vegas.

Four Corners is the hub at Shiprock and San Juan substations in northwestern New Mexico.

North Path 15 (NP15) is a delivery point north of transmission path 15 in California on selected ties between Los Banos and Gates.

The import and export patterns of the West help to explain prices in the region at any given time. California and Arizona are typically net importers. The Rocky Mountain Power Area is a net exporter. The Pacific Northwest exports a large volume of power, although it is seasonal in nature and varies from year to year.

With the deregulation of wholesale power markets, risk management has become a necessary part of trading in energy markets. Prior to Order 888, utilities traded to balance loads, buying power mostly from their neighbors with spare capacity. In that cooperative environment, risk management was not a priority. In the competitive market environment, risk management is an essential component of doing business.

Traders can hedge their contracts to reduce exposure to adverse price movements. A hedge is the purchase of a financial instrument to establish a position to offset the purchase or sale of energy. A hedge provides a form of insurance that the buyer or seller of power can obtain or pay a certain price for that power. Only a small percentage of hedge transactions actually result in the delivery of the energy. A number of hedging instruments are available to traders in western power markets.

A commonly used hedging instrument is the option contract. Options grant the right, but not the obligation, to buy or sell power for an agreed upon price over a specific period of time. An option allows a trader to exercise a "call" (the right to buy power) or a "put" (the right to sell power) at a given "strike" price before it expires. Options can take the form of futures contracts, swaps or the commodity itself.

Futures contracts are used by market participants to offset the price risk associated with buying and selling power. NYMEX also offers options contracts which give the holder the right to purchase or sell the underlying futures contract at a specified price within a specified period of time in exchange for a one-time premium payment.[2] There are three electricity futures contracts in the West—one based at the California-Oregon border (COB), one at Palo Verde, and one at Mid-Columbia. All of the contracts are offered by the New York Mercantile Exchange (NYMEX). The COB and Palo Verde contracts began trading on March 29, 1996. The Mid-Columbia contract, a recent addition, was launched on September 15, 2000. The standard trading unit for all of the contracts is 432 MWh onpeak power delivered over a monthly period.

Western market participants also rely heavily on forward contracts to protect themselves from price risk. A forward contract is a supply contract for future delivery of a fixed quantity of power at a predetermined price, time and location. Forward contracts are tailored transactions resulting from direct negotiation between a buyer and seller. They differ from futures contracts in that they are non standardized and non transferable. Forward contracts provide price certainty to both the buyer and seller, obligating them to accept the agreed-upon price, regardless of the market price when delivery takes place.

California has two specialized institutions that came into being during restructuring and alter the character of the California market when compared with the rest of the West: the Power Exchange (PX) and the Independent System Operator (Cal-ISO). The PX conducts day-ahead, day-of and block-forwards markets. The day-ahead market is

[2]Based on information from NYMEX web site: http://www.nymex.com.

essentially an auction system of 24 one-hourly markets, bid simultaneously and cleared all at once. The day-of market also consists of 24 auctions, although they are conducted in three batches over the course of the day. The block-forward market commenced on July 31, 1999, allowing market participants to hedge price risks. The original block-forward contracts were for the delivery of one MW for 16 hours per day, Monday through Saturday for a month. Contracts can be made in block multiples of 25 or singly in any quantity. The contracts were originally specified for delivery in either NP15 or SP15, through either the CalPX or the bilateral markets. Quarterly block- forward contracts became available on December 31, 1999. Super-peak and shoulder-peak contracts became available on March 1, 2000. In addition, the CalPX instituted a block-forward market for ancillary services on May 1, 2000.[3]

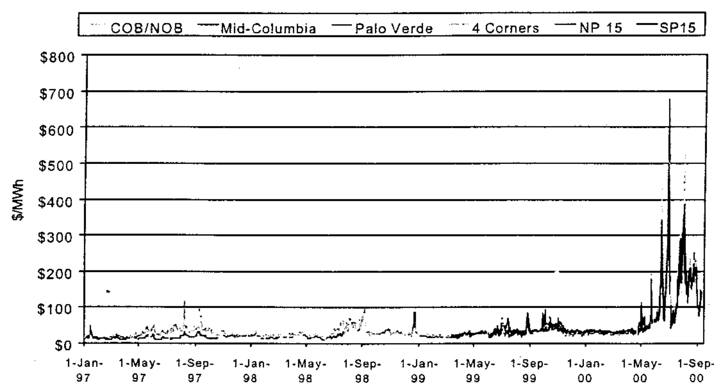
The ISO does not run a day-ahead energy market, but does conduct auctions for seven separate products: incremental and decremental energy; spinning, non-spinning and replacement reserves; and upward and downward regulation. These auctions are used to construct hour-ahead schedules for energy and ancillary services. Energy bids for ancillary services and supplemental energy are combined to create a real-time supply curve for energy. These bids are capped by the Cal-ISO price limits, which were $750 at the start of the summer, but were reduced to $500 in July and $250 in August. In extreme conditions, the Cal-ISO also engages in out-of-market (OOM) purchases for emergency supplies of energy. These emergency supplies are not subject to the price cap.

3. Recent Price Trends in Western Markets

Western price spikes during the summer of 2000 far exceeded prices seen in previous summers. Figure 3-1 shows index prices for all the western market hubs dating back to 1997. Previous price spikes exceeded $100 per MWh only once prior to the summer of 2000. Beginning in May 2000, prices spiked over $100 per MWh and the spikes increased continued through the summer.

[3]The Cal-ISO Department of Market Analysis reports "..only a nominal amount of ancillary service capacity traded in the Cal PX BFM," as of July 28, 2000. Cal-ISO Department of Market Analysis, Request to Extend Price Caps, filed with FERC August 14, 2000, ER00-3673, Attachment C, p. 8.

Figure 3-1. Daily Price Indices for Western Market Hubs, 1997-2000



May price spikes. The first spike of the season was in early May. Prices at Palo Verde prices rose well over $100 per MWh in response to hot weather and diminished supplies, with several generation units down for maintenance. The Northwest could not send supplies south because of its own demands and a large number of coal units were offline with unplanned outages. Daily index prices at Mid-Columbia reached over $65/MWh, but did not exceed prices at the typically higher-priced COB and Palo Verde.

In late May, a heat wave caused western prices to spike again, almost doubling the spike that occurred two weeks earlier. Hot weather, combined with 6,000 MW of off-line generation drove day ahead prices at all the western hubs over $200 per MWh. The Cal-ISO implemented State 2 emergency measures as reserves fell below 5 percent. Some non-firm loads were cut and the ISO bought supplemental power to prevent rolling blackouts. Real-time prices in the California PX rose to the ISO's $750 cap on ancillary services for several hours. The California PX average, onpeak day-ahead price topped $316/MWh, an all-time high.

June price spikes. In mid-June, western markets experienced another price spike, with prices reaching an unprecedented level for western markets. Daily index prices at

Palo Verde reached $450, with prices at COB reaching $430 and prices at Mid-Columbia reaching $400. Real-time prices in California hit the ISO's $750/MWh cap on ancillary services for three days straight. Hot weather, the shortage of hydro generation, and plant outages were cited in trade press reports of the spikes. Temperatures in San Francisco reached 105 degrees, breaking a 34-year record. The Cal-ISO ordered rolling blackouts, curtailed interruptible loads, and cut a small amount of firm power to customers in the San Francisco Bay area.

In the final week of June, bilateral prices rose to their highest levels to date as Bonneville Power Administration and the Northwest utilities outbid California and the Southwest, reportedly paying as much as $1,400/MWh to buy power in hourly bilateral markets.[4] Market players noted that, with caps in place in California markets, adjacent regions were able to outbid California, buying power out of the state. Hot weather, unit outages and hydro shortages were again cited by market participants as reasons for the spike. Daily index prices rose to $677 per MWh at Mid-Columbia, $648 per MWh at COB, $497 at NP-15 and $513 at Palo Verde.

July price spikes. Daily prices reached over $100 per MWh several times in July, mostly at the southwestern hubs. Prices showed a large spike near the end of the month, during a period of hot weather in the Southwest, with index prices at Four Corners and Palo Verde reaching over $320 per MWh, with prices $246 at COB and $233 at Mid-Columbia. Loads in Arizona set record highs, with the two utilities in Phoenix setting new highs on five days in July.[5] High loads in the Southwest left little power to import to California. Hot weather, combined with supply shortages sent up prices throughout the West.

August price spikes. Western hub prices remained at a significantly higher level for the month of August. Starting around mid-July, prices at the western hubs never fell below $110. The average index price for August was $211.33 at SP15, and $188.73 at NP15.

In early August, prices at Palo Verde reached $1,500 per MWh in hourly markets, with Palo Verde index prices escalating to $523 per MWh. Index prices at COB and Mid-Columbia reached almost $500 per MWh, hitting $481 and $472, respectively. High temperatures in the Southwest and in parts of California were partially responsible, but wildfires threatened transmission facilities and increased the pressure on prices.

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[4] "Traders See Northwest More Easily Outbidding California Under New ISO Cap," *Power Markets Week*, July 3, 2000, pp. 1, 12.

[5] "West Prepares for High Temps, Loads; Traders Brace for Vote on Price Caps," *Power Markets Week*, July 31, 2000.

Prices generally remained over $200 per MWh at the southwestern hubs for the duration of August. For the remaining hubs, prices fell below $200 for several days. But in late August, prices surged in the Northwest when hydro generation was restricted. Hydro supplies came to an abrupt halt as dam operators were forced to fill reservoirs so they could continue to provide power through the rest of the year.[6] Day-ahead prices at Mid-Columbia and COB increased to $260 per MWh.

Increase in overall price levels. The summer 2000 price levels greatly surpassed the price levels of prior years. Figures 3-2 to 3-4 compare prices at COB, Palo Verde and Mid-Columbia for the past three summers. The summer 2000 prices show a dramatically different pattern from the previous 2 years, with large spikes in May and June. In mid-July through August 2000, lower price caps limited the prices in hourly markets, but the general level of prices was significantly higher, hovering around $200. A similar trend can be seen at Palo Verde and Mid-Columbia, with extreme price spikes or high overall prices occurring throughout the summer in 2000, compared with much lower price levels for the previous two summers.

Prices in western markets show a close relationship to the prices in the California PX from which 80 percent of load, served by IOUs in California, must purchase energy. The California PX noted this relationship on an average basis for the May and June period.[7]

Figure 3-5 shows daily onpeak prices for NP15 and SP15 for bilateral markets and the California PX. While the prices track very closely, the PX prices show much larger spikes than the bilateral prices. The California PX products are not identical to the bilateral market products. The bilateral market prices are index prices for 16-hour blocks

[6]"N.W. Prices Escalate as Hydro Dwindles; Dams Store Water, Runoff Disappears," *Power Markets Week*, August 28, 2000.

[7]California PX Report on June 29, 2000, "Price Behavior in the CalPX Markets, May-June 2000."

Figure 3-2. Bilateral Index Prices at Palo Verde

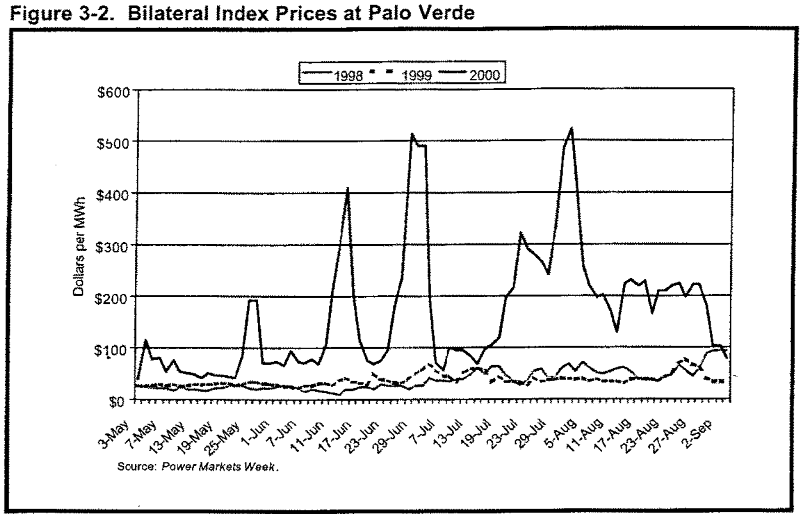


Figure 3-3. Bilateral Index Prices at COB

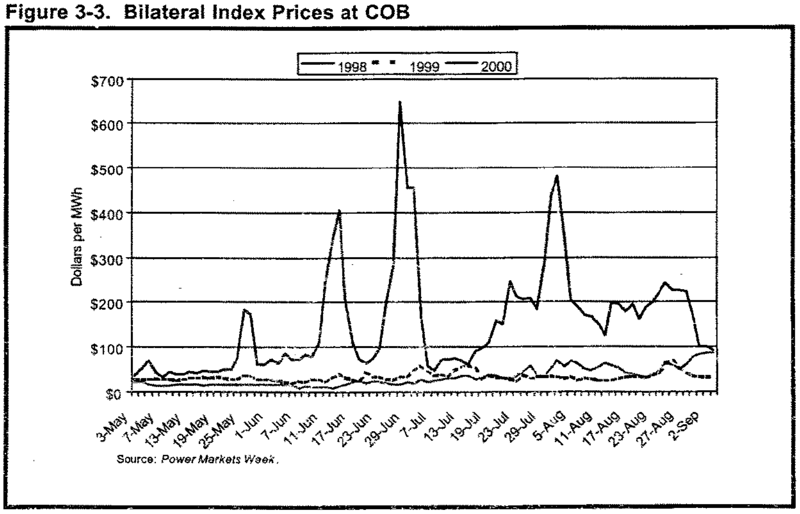
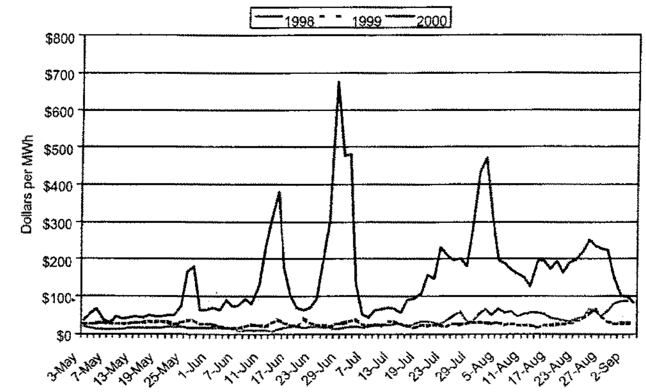
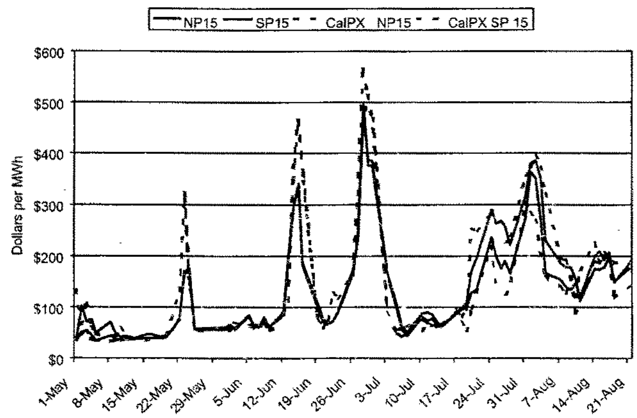


Figure 3-4. Bilateral Index Prices at Mid-Columbia



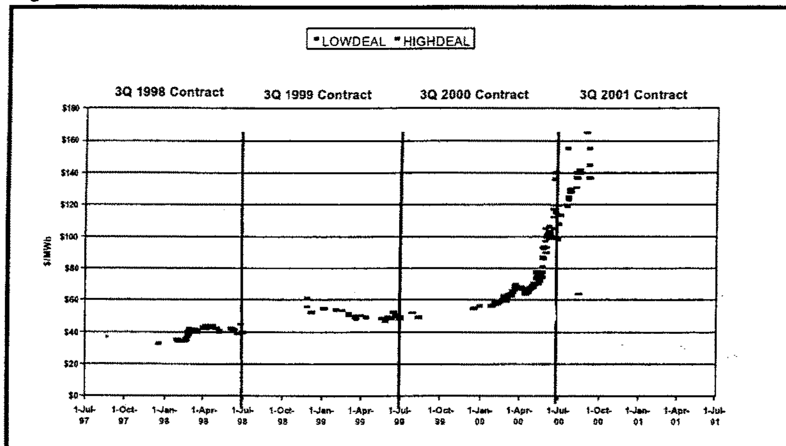
Source: *Power Markets Week*.

Figure 3-5. Western Market Prices for Summer 2000: Bilateral Markets vs. California PX



Source: RDI PowerDat. Bilateral prices are Power Markets Week 16-hour on-peak prices.

Figure 3-6. Palo Verde Forwards: 3rd Quarter Contracts



Source: Power Markets Week

of power. The PX prices and sells power on an hourly basis.[8] It is possible that, because these products are slightly different, they are valued differently at peak times.

The pattern of prices was different in July and August. The PX and bilateral market prices tracked more closely, with bilateral market prices often higher than PX prices at NP15 and PX prices remaining higher at SP15.

Forward market prices were much lower earlier in the year and were used by some market participants to hedge potentially high prices over the summer. Figure 3-6 shows

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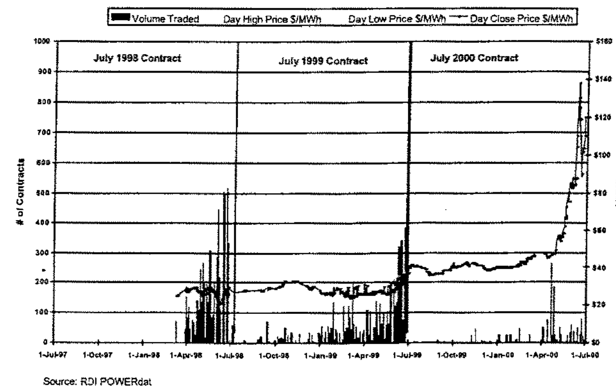
[8]The PX prices have been averaged for a 16-hour block period to correspond to the 16-hour block traded in bilateral markets, but the products are not the same because buyers and sellers in the PX set individual hourly prices whereas bilateral buyers and sellers trade at a single price for the entire block. Buying a block at a single price does not permit the buyer to tailor hourly prices to expected hourly levels, and is consequently less flexible, particularly if the buyer plans to resell in hourly markets.

forward contracts for the third quarter for the last 3 years (1998 through 2001) at Palo Verde, COB and Mid-Columbia. Forward prices have risen in each of the past 3 years. A substantial number of forward contracts were made in early 2000 at prices between $60 and $80 per MWh. Market participants who purchased forward contracts for the summer of 2000 received prices well below spot market prices. COB and Mid-Columbia had similar patterns, with somewhat lower prices for those hubs.

Figure 3-7 shows the July futures contract at COB for 1998 through 2001. While no July 1998 contracts were traded prior to March 1998, trading for both the 1999 and 2000 contracts began as early as one year earlier, as market players recognized the need to prepare for summer price spikes. Prices for July 2000 were as low as $50 per MWh up until April 2000. After April, the July contract escalated, reaching almost $140 per MWh prior to expiration. Futures prices that seemed high earlier in the year resulted in significant savings to those who used futures contracts to hedge their positions in the market. A similar pattern occurred for the August contracts at COB and Palo Verde.

The number of futures contracts traded declined substantially in 1999 and 2000. Market participants have noted in discussions that they find the futures contracts less flexible than individually tailored forward contracts, preferring to use over the counter forwards instead. A contract structured around a monthly market may not be sufficiently flexible to attract a large number of buyers in a market given to a high level of daily and hourly volatility, where both buyers and sellers may have different supply and demand profiles. Over-the-counter products customized to buyer and seller needs, while more expensive to arrange than current futures market products, may be the best alternative in the absence of greater ability to develop attractive standardized products.

Figure 3-7. COB Futures: July Contracts



4. Correlation of Prices in Western Markets

Bilateral and PX Markets

Table 3-2 shows the correlations of western market onpeak prices for the summer 2000 period. The correlations between California PX prices and western market bilateral prices are quite strong. As one would expect, the correlations between the California PX prices and bilateral prices at NP15 and SP15 are high. By the same token, CalPX NP15 and Mid-Columbia are highly correlated, as are CalPX SP15 and Palo Verde because of the geographic proximity of the points and the general absence of transmission limits into California. Correlations between all of the western onpeak prices show correlations of 0.858 or above.

Table 3-2. Correlations of Western Market Prices: Onpeak Prices from Megawatt Daily and California Power Exchange
(May 1-August 21, 2000)

	COB/ NOB	Mid-Columbia	Palo Verde	4 Corners	NP15	SP15	Cal PX NP15	Cal PX SP15
COB/NOB	1.000							
Mid-Columbia	0.997	1.000						
Palo Verde	0.971	0.963	1.000					
4 Corners	0.961	0.953	0.995	1.000				
NP 15	0.992	0.987	0.974	0.966	1.000			
SP 15	0.969	0.960	0.992	0.983	0.977	1.000		
CalPX NP15	0.912	0.908	0.865	0.858	0.919	0.876	1.000	
CalPX SP15	0.915	0.906	0.932	0.932	0.922	0.937	0.930	1.000

Table 3-3 shows the correlations of offpeak western market prices. The correlations of offpeak prices show strong relationships between prices in bilateral markets, but the relationships between prices in the CalPX and bilateral markets are weaker. The CalPX SP15 price shows a higher correlation to all the bilateral prices than does the NP15 price. One would expect the CalPX NP15 to more closely correlate to the COB/NOB price because it is closer in proximity.

During summer 2000, power flowed into the Northwest from California especially during offpeak hours to allow hydro generators to store water for more costly onpeak hours.[9] It is possible that the demand for exports of offpeak power from California to the Northwest created a different pattern of prices for markets in northern California.

[9] "N.W. Prices Escalate as Hydro Dwindles; Dams Store Water, Runoff Disappears," *Power Markets Week*, p. 11.

Table 3-3. Correlations of Western Market Prices: Offpeak Prices from Megawatt Daily and California Power Exchange
(May 1-August 21, 2000)

	COB/NOB	Mid-Columbia	Palo Verde	4 Corners	CalPX NP15	CalPX SP15
COB/NOB	1.000					
Mid-Columbia	0.963	1.000				
Palo Verde	0.946	0.942	1.000			
4 Corners	0.848	0.881	0.946	1.000		
CalPX NP15	0.499	0.568	0.422	0.596	1.000	
CalPX SP15	0.742	0.699	0.700	0.554	0.702	1.000

ISO Energy and Ancillary Services Markets

Ancillary Services prices showed a similar pattern to that of energy prices in the PX and ISO during the summer of 2000. As shown in Figure 3-8, spinning, non-spinning and replacement reserves reached the level of the price cap ($750 per MW in May and June, $500 per MW in July and $250 per MW in August) for periods throughout the summer. These patterns track with the energy market price and reflect the opportunity cost of generators' providing ancillary services. That is, if generators are holding a portion of their units in reserve, they are foregoing the revenue they could have earned by providing energy in the day-ahead, hour-ahead, or real-time markets.

The ISO instituted an additional purchase price cap for replacement reserves at $100 per MW as part of a strategy to reduce out-of-market calls associated with under-scheduling. As shown in Figure 3-9, the ISO increased the amount of replacement reserves it purchased in July and August relative to the level it had purchased in May and early June.

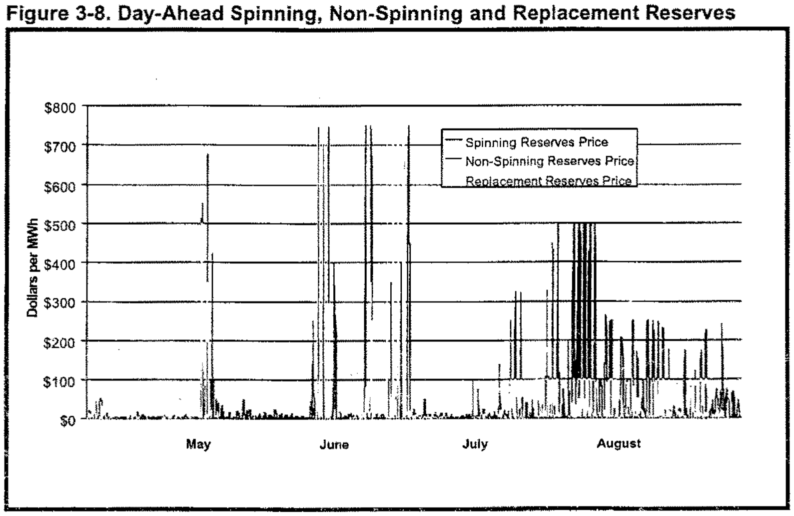
The Cal-ISO reports that the strategy to reduce the reliance on out-of-market calls may have increased generators' incentive to withhold capacity from the day-ahead PX energy market and shift capacity into replacement reserve and real-time energy markets during the high load periods.[10] Suppliers could benefit by not scheduling capacity in the day-ahead markets, and instead bidding into the replacement reserve market so that they have a high probability of receiving both the capacity payment for replacement reserves and

[10] *Report on the California Energy Market Issues and Performance: May-June 2000*, prepared by the Department of Market Analysis, California Independent System Operator, August 10, 2000.

also the real time energy price. During high load periods, the replacement reserve price can be high and a high proportion of all available energy is likely to be taken by the Cal-ISO, so this can be a profitable strategy. In July, the Cal-ISO lowered the price cap on replacement reserves in an attempt to limit the attractiveness of this strategy.[11]

Real-time energy prices in the Cal-ISO closely follow the PX prices for the same period. As described above, these two markets are linked since one is effectively a substitute for the other from both the supply and demand perspectives. It is also clear that the real-time energy and PX prices experienced longer periods of prices at or near the price cap than the ancillary service price.

Figure 3-8. Day-Ahead Spinning, Non-Spinning and Replacement Reserves



[11] California ISO, "Minutes of Special Board of Governors Meeting," June 28, 2000.

Figure 3-9. Day-Ahead and Hour-Ahead Replacement Reserve MWh, NP15

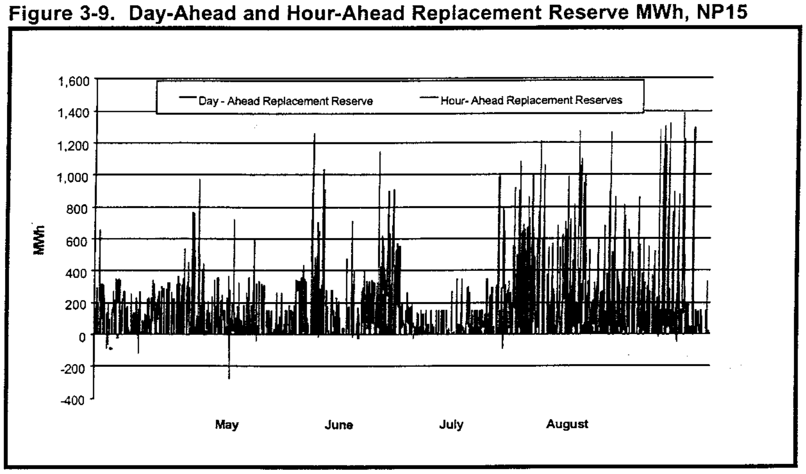


Figure 3-10. Daily Spot Prices for Western Natural Gas Markets in 2000

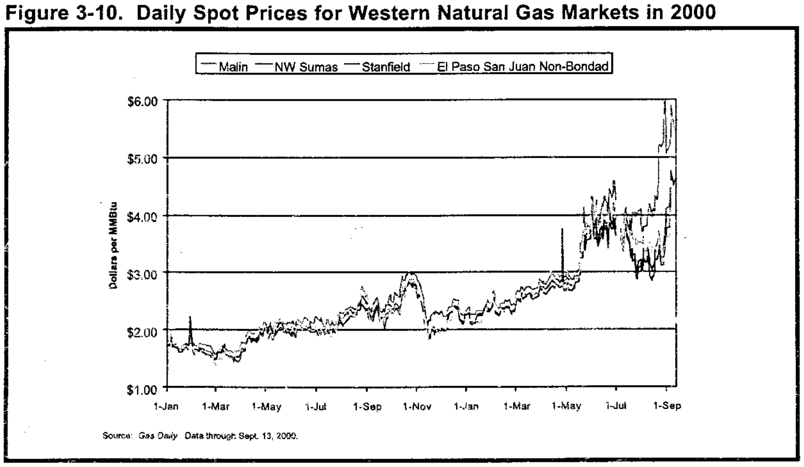
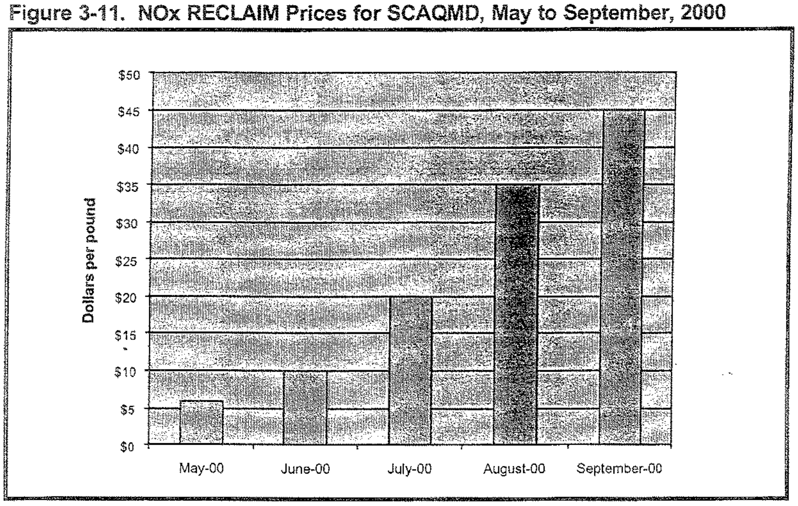


Figure 3-11. NOx RECLAIM Prices for SCAQMD, May to September, 2000



B. Cost Factors in Prices and Price Increases

1. Input Price Increases

One of the reasons for the higher prices in the West during the summer of 2000 was the increase in input prices, specifically increases in natural gas prices and NOx compliance costs. As shown in Figure 3-10, natural gas prices roughly tripled from January 2000 to September 2000 in the West.

Since natural gas-fired units are usually the marginal units during peak demand periods, input price increases can have a significant impact on the market clearing price. For example, for a gas-fired unit with a heat rate of 10,000 Btu/kWh, if the natural gas price goes from $2.00/MMBtu to $5.00/MMBtu, the fuel cost rises from $20.00/MWh to $50.00/MWh.

In addition, the price of the NOx credits necessary to run gas units also increased significantly. As shown in Figure 3-11, the price of NOx RECLAIM credits rose from approximately \$6.00/lb to over \$40/lb at the end of August.[12] A combined-cycle gas generator typically emits around 1 pound of NOx per MWh. A combustion turbine gas peaking unit can emit more than 2 pounds of NOx per MWh. At a price of \$40/lb, the emission reduction cost of a gas peaking unit would be approximately \$80/MWh as opposed to \$12.00/MWh when the NOx credit price is only \$6.00/lb. Taken together, the increases in natural gas and NOx credit prices raised the marginal running cost of a combined cycle generation unit with a heat rate of 10,000 Btu/kWh and a NOx emission rate of 1 lb/MWh by approximately \$64.00 per MWh (from \$26.00 to \$90.00 per MWh).

Most critically, in times of peak demand when internal and external transmission constraints limit transfers, the least-efficient plants are called on to provide energy and thus set the market-clearing price. These plants have the highest heat rates and some of the highest NOx per MWh emission rates. In these cases, the marginal running cost of the plant is significantly above \$100/MWh. For example, for a combustion turbine gas-fired peaking plant with a heat rate of 16,000 Btu/kWh with a NOx emission rate of 2 lbs/MWh, marginal running cost would have risen from \$44/MWh to \$160/MWh.[13] Therefore, market clearing prices that approach the \$250/MWh price cap may simply reflect the true cost of the resource and be solely the result of tight supply, not the exercise of market power. Figure 3-12 shows the effect of rising natural gas prices and NOx emission permit

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[12]The prices in Figure 3-11 are averages based on sales reported by Cantor Fitzgerald Environmental Brokerage Services, www.cantor.com/ebs. The May, June and July and August figures reflect both vintage 1999 and 2000 RECLAIM allowances. The September figure is for vintage 2000. June 1999 RECLAIM allowances expired at the end of August 2000.

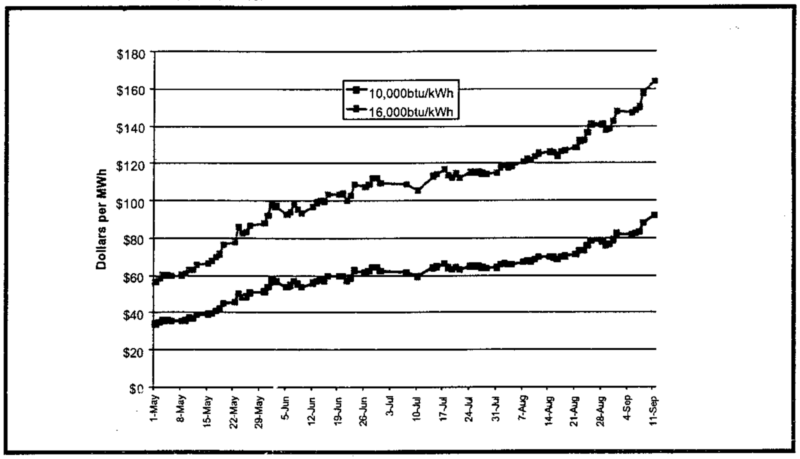
[13]Both examples assume an increase in the natural gas price from \$2 per MMBtu to \$5 per MMBtu and an increase in the NOx emissions credit price from \$6.00/lb to \$40/lb. Under extreme conditions gas-fired units with heat rates exceeding 16,000 Btu/kWh may be called on to produce energy in the PX or real-time energy markets. The ISO DMA uses somewhat more extreme emissions and heat rate assumptions in Market Analysis Report, September 2000, basing costs on a NOx rate of 4 lb/MWh and at heat rate of 20,000 for a combustion turbine. These extremes can be reached, but only in the most extreme emergencies. However, they use \$35 for NOx costs, the approximate August average, rather than the end of August price. They estimate a price of just under \$250 rather than the lower number we provide here. Given the uncertainties in the information, either estimate is consistent with high prices close to \$250 in August.

rates on the running cost of gas-fired generation from a combustion turbine emitting 2 lbs NOx per MWh over the summer of 2000.[14]

C. Bidding in the CalPX and Selected Cal-ISO Markets

This section discusses bidding patterns in the PX and the ISO replacement reserve market, and the role of out-of-market purchases by the ISO. These discussions provide information on the patterns that appear to have driven the high prices encountered in the summer of 2000. The PX bidding is discussed first, followed by bidding in the ISO replacement reserves and out of market purchases.

Figure 3-12. Estimated Running Cost for Gas-Fired Generation in Southern California



[14]Cost estimates based on stated heat rates, average western hub gas prices from the four hubs shown in Figure 3-10, assumed NOx emission rates of 1 and 2 lb per MWh, for the 10,000 and 16,000 Btu/kWh heat rates respectively, and a linear estimate of NOx reclaim prices ranging from $6.00/lb. on May 1 to $40.00/lb on August 31. Note, the NOx emission rate is not simply of function of the heat rate, it also depends on the unit-specific NOx burn rate. That is, two different combustion turbines with the same heat rates could have different NOx emission rates.

1. Bidding in the CalPX

In the last section, the decrease in the amount of power scheduled through the PX on a day-ahead basis was described. Given the requirement for balanced schedules in the California design, the reduction in the proportion of power scheduled day-ahead is the joint result of bidding by both supply and demand. However, much of the change has been driven by suppliers migrating to other markets, such as the real-time market or the export market. As a result, there is a clear reduction in the total supply available in 2000 compared with 1999. This result has been documented by the recent analysis provided by the PX.[15] This section further examines bidding patterns over the last summer to determine how the pattern changed as the Cal-ISO price cap changed over the summer. Although the PX has no price cap, the Cal-ISO cap provides a *de facto* cap, since the Cal-ISO markets provide an alternative for both loads and supply. Loads will have an incentive to move their purchases to the Cal-ISO rather than bid to raise prices in the PX above the Cal-ISO price cap. And suppliers have incentives to shift sales to Cal-ISO markets at peak times in hopes of gaining a capacity payment for replacement reserves and also being paid at the price cap for real-time energy.[16]

For these reasons, one would expect the level of the price cap to have some detectable impact on bidding behavior. This impact is examined from two primary perspectives. First, differences in the total amount of supply offered into the day-ahead PX market are examined. Second, changes in the shape of bid curves are examined by studying the proportion of supply offered at selected price levels.

Quantities of Supply Bid into the PX

To examine how supply quantities bid into the PX changed over periods with different Cal-ISO price caps, the quantity of supply made available under the price cap was calculated from bidding data by participants. Participants were classified by the following categories used by the PX. The three largest participants are the California IOUs, the new generation owners (NGOs) who have acquired the divested units previously owned by the California IOUs, and the power marketers. These entities account for over 90 percent of

15 California Power Exchange Corporation Compliance Unit, Price Movements in California Electricity Markets, September 29, 2000.

16 For further discussion of incentives for shifting supply away from the day-ahead PX market, see California PX Report, September 29, 2000, ISO Market Surveillance Committee Report, September 6, 2000, and report from the ISO Department of Market Analysis, August 10, 2000.

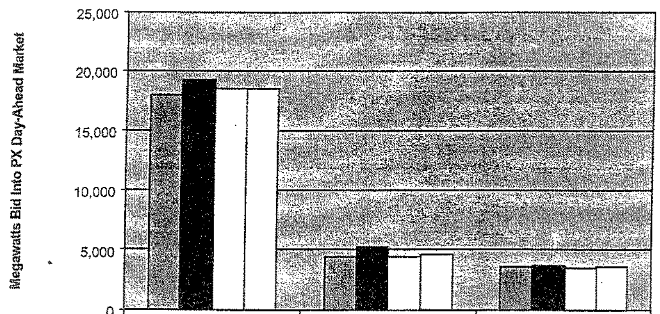
the quantities bid into the PX market. Other participants with smaller shares include municipal and other governmental participants and IOUs outside California.

Figure 3-13 shows the quantity bid into the PX under the Cal-ISO price cap for three time periods defined by the level of the Cal-ISO price cap[17] and the three major participant categories. The quantities represent the average total quantity bid hourly during onpeak hours over the period. There appears to be little or no change in the total quantity bid for any of the participant categories. Figure 3-13 includes all supplies bid, and includes the quantities bid in at zero prices, which make up around two-thirds of the total and may not change appreciably when the price cap changes. However, it is interesting to note that the price cap seemed to have a relatively small impact on the total quantity bid.

In each participant category, slightly more supply is bid into the PX in July, when the price cap was at $500, than in the other two periods when the cap was lower or higher. This period corresponds to the time when the supply/demand picture was less tight than it was before, in June, or afterwards, in August. Under these conditions, there may be fewer opportunities to sell outside of California because supplies in the West were generally more abundant.

[17] The $750 period extends from May 1 to June 30, the $500 period from July 1 to August 6, and the $250 period from August 7 to September 20. Although the $250 period extends past the end of August, used as the end date for other statistics in the report, it was used here to make use of the additional information gained by the extension.

Figure 3-13. Comparison of PX Onpeak Supply Bid Under ISO Cap for Selected Participant Types



	Cal IOUs	New Generation Owners	Power Marketers
ISO Cap=$250	18,018	4,445	3,506
ISO Cap=$500	19,270	5,277	3,615
ISO Cap=$750	18,514	4,441	3,483
Onpeak Total	18,544	4,647	3,523

Changes in Bid Shape

August prices were higher than June prices on average in both the PX and the ISO, even though the ISO cap was reduced from $750 to $250 over the period. The higher price in the PX is a result of upward shift in the supply offered in the PX. This upward shift can be seen by calculating the percentage of supply offered at any given price level. Table 3-4 shows the percentage of supply offered at $100, $150 and $200. Figure 3-14 depicts the percentages offered at $100. These percentages clearly show that all participant categories changed the supply they offered as the price cap was reduced, particularly when the price cap fell to $250. However, it may be incorrect to attribute the change in bidding patterns solely, or even primarily, to the price cap reduction. As

Figure 3-14. Percentage of Non-Zero Supply Bid at $100 or Below

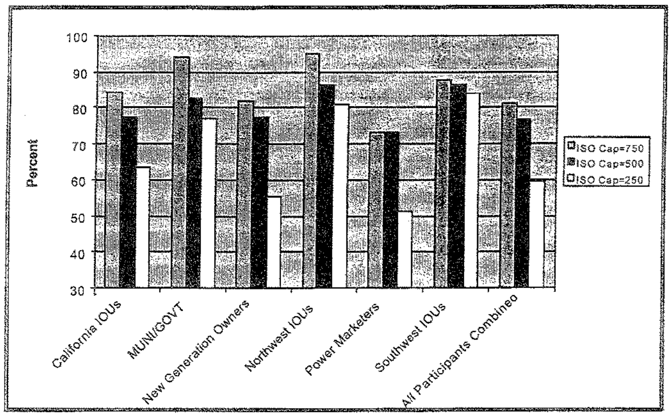


Table 3-4. Bidding in the CalPX by Participant and Cal-ISO Price Cap, May to September 2000

ISO Price Cap	California IOUs	Municipal/ Government	New Generation Owners	Northwest IOUs	Power Marketers	Southwest IOUs	All Participants
Percent of Non-Zero Supply Offered at $100							
250	63.4	76.9	55.5	81.0	51.1	84.0	59.6
500	77.2	82.5	77.5	86.3	73.2	86.5	76.8
750	84.4	94.1	82.0	95.2	73.1	87.7	81.3
Percent of Non-Zero Supply Offered at $150							
250	83.3	81.6	72.9	86.9	66.6	91.7	74.9
500	88.1	85.3	82.6	92.8	79.9	90.9	83.7
750	88.7	96.7	88.0	97.7	75.6	90.7	85.4
Percent of Non-zero Supply offered at $200							
250	89.6	87.4	84.3	91.7	76.6	94.9	83.2
500	91.4	90.0	86.5	96.3	83.0	93.0	87.2
750	91.1	97.2	91.2	98.8	77.8	92.2	87.8

discussed in the last section, costs rose over the same period, shifting costs upward and changing the underlying cost structure. Since all participant categories exhibit the same pattern, the changed bid shapes are unlikely to be the result of individual participants or classes of participants changing their bidding behavior in an attempt to manipulate prices.

2. Cal-ISO Replacement Reserve Markets and Out-of-Market Purchases

Both replacement reserve markets and out of market purchases by the Cal-ISO were closely related to the problem of underscheduling in the Summer of 2000. When underscheduling in the day-ahead and hour-ahead markets occurred, the ISO turned to replacement reserve markets or out-of-market (OOM) purchases to procure capacity needed to provide energy for meeting the difference between the forecasted load and the scheduled supply. The policy of purchasing replacement reserves for this purpose was motivated in part by the desire to limit the use of out of market calls, which take place outside the structure of the normal market during emergencies and are not subject to the price cap. As a result of these policies, OOM purchases were only a small portion of total energy costs in May through August. OOM purchases totaled $93 million dollars, less than 1 percent of the total energy costs of $11.6 billion. Around half of the cost and quantity of OOM purchases were for power from public entities or scheduled through public entities as scheduling coordinators.

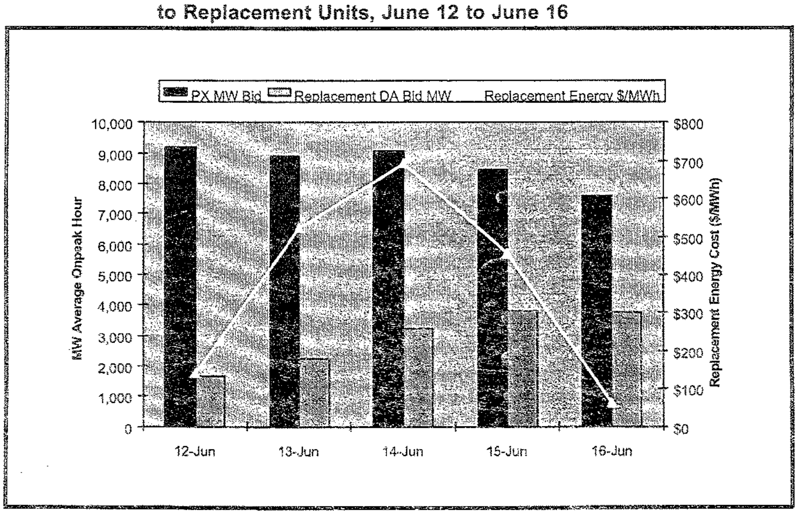
Replacement reserve total costs were much greater than OOM purchase costs, totaling $217 million dollars in June alone, almost half the total ancillary service costs of $436 million dollars for the month. Examining bids and bid patterns for two high-costs weeks in June showed a pattern of increased bidding into the replacement reserve market as the week progressed. The quantities bid into the replacement reserve markets are shown in Figure 3-15, where these quantities are compared with quantities bid into the PX for the week of June 12 to 16. Replacement reserve costs for Tuesday to Thursday of this week were over $120 million. It appears that more offers are placed in the replacement reserve markets this week as the hotter weather sets in, while the quantity bid into the PX falls or remains level. This information confirms that bidders are following their incentives to place supplies in the replacement reserve market, where they can obtain payment for both reserve capacity and for replacement energy when called. Given these incentives, bidders would shift additional supplies to the day-ahead or hour-ahead replacement reserve market, rather than the day-ahead PX energy market, in order to obtain additional payment for reserve capacity. While there are a range of bidding patterns in the replacement market, no one participant or class appears to dominate others in setting the overall pattern. It is also interesting to note that the higher level of bidding into replacement markets continues even on Friday, June 16, when replacement reserve costs and purchases by the ISO have fallen to low levels.

3. Transmission Congestion Costs and Prices

Transmission was not a major issue in 2000 in most discussions with market participants. However, as noted in Section 2.B.6, transmission congestion patterns shifted in 2000 compared to earlier years, but congestion remained significant. Transmission congestion on paths into California generally lessened, but congestion on major paths within California, Path 15 and Path 26, worsened during some periods. Overall, day-ahead, interzonal congestion costs were $141 million in May to August 2000 compared with $27 million in 1999. However, $81 million of the cost was for congestion on Path 26, which not counted as interzonal congestion cost prior to the start of zone ZP26 in February, 2000. If these charges are removed, year 2000 costs are $60 million in 2000. This indicates that comparably-compared congestion costs about doubled from 1999, a somewhat smaller increase than overall energy costs.

Table 3-5 shows the congestion charges on the major transmission paths in 1999 and 2000. In general, the total cost impact of imports was less in 2000, particularly during peak periods. Costs for imports were much lower in 2000 on COI, during both peak and offpeak periods. As shown earlier in Table 2-18, import flows on NOB and Eldorado were

Figure 3-15. CalPX Bids, Replacement Reserves and Real-Time Payments to Replacement Units, June 12 to June 16



much lower in 1999, so the higher charges in 2000 for these paths, shown in Table 3-5 did not have as much impact. However, internal California paths, that affected the price difference between NP15 and SP15, Path 15 and Path 26, were both congested more often in 2000 than in 1999 and had cost per MWh of congestion. Exports flowing north offpeak were also more frequent and more costly per MWh, as show in Table 2-18 and in Table 3-5.

Table 3-5. Transmission Congestion Price During Congested Hours on Major Congested Paths, May through August, 1999 and 2000

Transmission Path	1999	2000	Difference (2000 minus 1999)
Onpeak Congestion			
Imports over Cal-Oregon Intertie (COI)	$13.96	$0.50	-$13.46
Imports from Oregon over DC Tie (NOB)	$5.15	$16.47	$11.32
North to South flow on Path 15	$12.18	$34.78	$22.60
North to South flow on Path 26	$0.00	$61.21	$61.21
Offpeak Congestion			
Imports over Cal-Oregon Intertie (COI)	$9.19	$0.00	-$9.19
Imports from Southwest over Eldorado Path	$4.83	$7.86	$3.03
Exports Oregon over DC Tie (NOB)	$4.83	$27.25	$22.42
South to North flow on Path 15	$5.91	$24.99	$19.08

4. Regulatory and Institutional Environment

The regulatory framework applicable to energy markets in the West is composed of a complex interaction of federal and state requirements related to energy and the environment.[1] As described below, in California, restructured markets were designed through a political process involving state, federal, and stakeholder inputs. The result of this process was an extremely complicated market design, with continued state and federal oversight at every organizational level. Furthermore, the new market entities created to implement restructured markets in California, the California Independent System Operator Corporation (Cal-ISO) and the California Power Exchange Corporation (PX), are governed by interested stakeholder boards which are charged with sorting through these political and market complexities, while maintaining a fiduciary duty to the Cal-ISO and PX. These are further overseen by an Electricity Oversight Board. All of this is in addition to the traditional regulatory oversight of the Federal Energy Regulatory Commission and the California Public Utilities Commission (CPUC).

Environmental regulation in California affects the siting and operation of generation and transmission projects. As discussed below, the regulatory structure is complicated and involves many layers of state and federal regulation. Local air quality factors have become of particular importance. Consequently, the review process for siting new transmission or generation facilities is frequently very lengthy; and, once constructed, environmental standards can significantly affect operations and generation costs.

A. Economic Regulation of Utilities

1. Federal Economic Regulation

The Federal Energy Regulatory Commission (Commission) is the principal federal regulatory agency responsible for electric regulation in the Western Systems Coordinating Council (WSCC) region.[2] The Commission regulates the rates, and terms and conditions governing the sale and

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[1] While other states in the West have passed restructuring initiatives, they have not been fully implemented and do not pose the regulatory complexities observed in California. Therefore, our primary focus is on the regulatory structures in California.

[2] The Commission also regulates: (1) the licensing, operations, and safety of all non-federal hydroelectric facilities located on navigable streams and facilities constructed after 1935 which are located on waters over which Congress has Commerce Clause jurisdiction and which affect the interests of interstate or foreign commerce; (2) the rates, terms and conditions for the transportation and sale for resale of gas in interstate commerce; and (3) the siting, construction and abandonment of interstate pipelines.

transmission of bulk power in interstate commerce under the Federal Power Act.[3] The Commission's mandate under the FPA is to assure that rates and terms and conditions are just and reasonable and not unduly discriminatory or preferential. The Commission's authority extends to the structure of both ISOs and the RTOs.[4] The Commission has limited authority over municipal, state, or federally owned generating and transmission facilities under the Federal Power Act. The Commission has permitted many generating entities in the west to charge market-based rates for the power they sell.

2. Economic Regulation of Electric Utilities in California

The State Regulatory Structure

Economic regulation of electric utilities in California is conducted by several agencies. Electric restructuring in California was initiated by the CPUC, which issued a series of policy decisions in 1994 and 1995. These decisions were followed by legislative enactment of Restructuring Legislation, under Assembly Bill 1890 (AB 1890). These state actions were taken in conjunction with a massive stakeholder process in which all segments of the California electric industry participated in developing the new market structure. Ultimately, the fruits of this process were submitted to the Commission for review.

Among other things, the new regime provided for establishment of two new entities, the California ISO and PX, to reliably operate the California transmission grid and to provide a spot market for electric energy; mandatory divestiture by California IOUs of significant portions of their generation; transfer of operational control of IOU transmission facilities to the Cal-ISO; implementation of retail access as of January 1, 1998, a non-bypassable Competition Transition Charge (CTC) which will allow IOUs to recover stranded costs through March 2002, a rate freeze to remain in place until the IOUs recover their stranded costs; a mandatory buy-sell requirement to ensure that the PX is a viable market entity; market monitoring within the ISO and PX; and oversight by several state agencies.

The CPUC regulates the retail rates of all privately owned electric utilities in California, but does not regulate municipal electrical corporations, which include some 14 municipal power companies,

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[3] Federal Power Act, Part II, 16 USC § 824, et seq; Pacific Gas and Electric Co., et al., 77 FERC ¶ 61,818 (1996).

[4] *See, e.g.*, Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Statutes and Regulations ¶ 31,089 at 30,994 and 31,037 (2000). In reviewing ISO or RTO filings, the Commission considers: the tariffs of such organizations, the terms for access to the interstate grid, the structure of their governing boards, delegated enforcement activities, and provisions such as an OASIS designed to assure non-discriminatory access to information regarding the operation of the electricity grid.

1 cooperative, and 4 state power authorities. The CPUC is responsible for evaluating the economic need for additional transmission capacity and reviews the reasonableness of proposed construction costs for rate making purposes once construction has been completed. Under AB 1890, the CPUC is charged with implementing direct retail access, regulating retail rates and services of state-regulated IOUs, retail distribution operation and reliability, IOU mergers, consumers protection and education programs regarding retail electricity services, administration of IOU contracts with qualifying facilities, examination of market behavior of IOUs and their affiliate transactions, and implementing the CTC mechanism as a non-bypassable charge on all customers.[5]

AB 1890 created a new regulatory entity, the California Electricity Oversight Board (EOB), to provide an oversight function over the ISO and PX. As modified by Senate Bill 96, the EOB's functions include monitoring, evaluating and representing state interests concerning the operation and reliability of the interconnected electric transmission system and the markets for generation and bulk energy including the ISO and PX and similar entities, and the rules and policies affecting these entities.[6] In addition, the EOB has the right to approve procedures and qualifications of, and to confirm the appointments of, Cal-ISO and PX governing board members representing retail and end-use classes.[7] Furthermore, the EOB has the right to serve as an appeal body for majority decisions of the ISO governing board related to matters exclusively within California's jurisdiction. The EOB consists of three voting members appointed by the Governor of California, and two non-voting members appointed by the California House and Senate, respectively, plus a professional staff of analysts and lawyers.

Under the AB 1890, two new entities were established to operate and to maintain the reliability of the interstate transmission grid and to operate a spot market for electric energy. The Cal-ISO is responsible for operating most of the transmission system in California. The ISO-controlled grid excludes local distribution facilities and facilities owned by municipalities that have not joined the ISO. The ISO controls, but does not own the network which remains titled in the name of its member companies. The ISO receives balanced operating schedules from the various scheduling coordinators to transmit power throughout the state. The ISO is responsible for resolving congestion issues within its system, for purchasing power needed to maintain system reliability, and for evaluating and determining the need for transmission system upgrades of the network it is responsible for operating. The authority of the ISO to require upgrades of the network it is charged with operating is subject to the concurrence of the owning utility. The ISO also operates a real time balancing market and ancillary services markets, and is responsible for all coordinating and regional reliability obligations involving the WSCC.

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[5] *See* Draft Memorandum of Understanding between the EOB and CPUC, January 20, 1999.

[6] *Id.*

[7] The EOB has the exclusive right to decline to confirm representatives of the agricultural end-user, industrial end-user, commercial-end-user, residential end-user, end-user at large, nonmarket participant and public interest group classes.

The ISO is governed by a 26-member stakeholder board, consisting of representatives of the following classes: CEO and President; Investor-Owned Utility Transmission Owners (3 members); Municipal Utilities (4 members); Government Market Participant Entities (1 member); Non-Utility Electric Sellers (2 members); Public Byers and Sellers (1 member); Private Buyers and Sellers (1 member); Agricultural End-Users (1 member); Industrial End-Users (1 member); Commercial End-Users (1 member); Residential End-Users (2 members); End-User at Large (4 members); Public Interest Groups (2 members); Non-Market Participants (2 members); plus several non-voting Advisory representatives. The ISO bylaws and structure require at least a majority vote to pass motions. This structure ensures that no two classes of customers can combine to dominate ISO Board decision making. The Cal-ISO has a market monitoring unit, called the Department of Market Analysis, and an external Market Surveillance Committee.

The PX was created under AB 1890 to function as the principal power market in California. The PX establishes prices for a day-ahead market based on demand quantities and prices it receives from parties trading through the PX. These prices incorporate the amount that parties are willing to pay as congestion relief charges. The PX is also a scheduling coordinator in the ISO. Once the day-ahead price and quantities are established, the PX submits the balanced schedules to the ISO. If congestion develops, another round of schedules, which incorporates congestion charges, is developed and submitted to the ISO. The PX also acts as a clearing house for the daily and hourly markets. Under AB 1890, the three major electric utility companies in California (SDG&E, SoCal Edison and PG&E) are required to make all of their purchases through the PX. Since 1999, the PX has operated a block-forward market in an attempt to provide greater depth and to allow participants to hedge against price volatility. The PX has both an internal market monitoring compliance unit and an external Market Monitoring Committee to maintain vigilance against market abuses in the newly restructured environment.

Like the ISO Governing Board, the PX Governing Board is a stakeholder board, representing the following classes: CEO and President; Privately Owned Distribution Companies (3 members); Publicly Owned Distribution Companies (3 members); Public Buyers and Sellers (2 members); Private Buyers and Sellers (2 members); Non-Utility Generators (3 members); Agricultural End-Users (1 member); Industrial End-Users (1 member); Commercial End-Users (1 member); Residential End-Users (2 members); End-User at Large (3 members); Public Interest Groups (2 members); Non-Market Participants (2 members); plus several non-voting Advisory representatives. Like the ISO, the PX Governing Board has structural checks against dominance by any one or two voting classes.

The CPUC and EOB recently have recommended that the stakeholder boards should be eliminated and replaced with boards appointed by the Governor.[8] They have also recommended that the EOB's authority over the PX and Cal-ISO should be clarified and that either the CPUC or the

[8]EOB/CPUC Report to the Governor, at 46-47.

EOB should be given authority to sanction power plant owners, electricity sellers or scheduling coordinators.

CPUC Policies for IOU Generation and Purchases

The California Commission's Preferred Policy Decision, 64 CPUC2d, 1 (1994) required PG&E, SoCal Edison and SDG&E to bid all of their generation into the PX and to procure electric energy for their full service customers by purchases from the PX. (*Id.* at 95). This "buy/sell requirement" remains in effect for a period consistent with the rate freeze and the IOUs' collection of stranded costs through the CTC.

The CPUC's stated rationale for the buy/sell requirement was to provide price transparency, mitigate market power and reduce regulatory burdens, to ensure that customers relying on their distribution utility to procure their electric energy would receive the benefits of competitive market prices, and to provide sufficient depth to the PX that its market signals may be relied upon as a benchmark for choices to opt for contracts for differences or direct access arrangements. (64 CPUC 2d 1, at 38).

In its initial orders on the proposed restructuring, the Commission independently adopted the California buy/sell requirement. Although the Commission stated that it might be concerned if this was a long-term requirement, it found that the buy/sell requirement was important to the entire restructuring proposal and that it was acceptable as a transition mechanism that would be in place for a limited, 5-year period.[9] Until the PX implemented the block-forward market, the buy/sell requirement limited the IOUs to the PX day-ahead market for their supply, and precluded the use of forward contracts to hedge the risk of price spikes in the spot market.

As originally proposed and authorized, the PX block-forward market was limited to bilateral energy transactions up to 12 months in advance of delivery.[10] The California IOUs were required to secure permission from the California Commission to participate in the PX block-forward market. Prior to the implementation of the block-forward market, the CPUC gave very limited authority to the IOUs to engage in hedging.[11]

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[9]Pacific Gas and Electric Company, et al., 77 FERC ¶ 61,265 at p. 62,088-89 (1996).

[10]California Power Exchange Corp., 87 FERC ¶ 61,203 (1999);

[11]The decisions of the CPUC are reported in the following cases: PG&E, D.97-08-058(1997)(denied request to use financial instruments to hedge); PG&E, D.98-06-076(1998)(granted, with conditions, request to use gas-indexed financial instruments to hedge gas costs for power production); SoCal Edison, D.99-07-018(1999)(dismissed request to implement pilot program for bilateral agreements for energy and capacity purchases up to 2000MW); SDG&E, D.97-12-088(1996)(denied request to purchase power in bilateral market which would then be bid into the PX

The IOUs sought authority to participate in the block-forward market in April and May 1999. On July 8, 1999, the CPUC granted the IOUs permission to use the PX block-forward market through October 2000, for up to one third of their respective hourly loads per month. [12] For the summer of 2000, these limits were: 300-400 MW for SDG&E; 2,000 MW for PG&E; and 1,800-2,000 MW for SoCal Edison. The CPUC also conditioned such hedging on reasonableness reviews. [13]

The PX began offering expanded block-forward market products in the spring of 2000, including super peak and shoulder peak energy products and peak energy products from surrounding states. The PX also proposed to offer a block-forward market for ancillary services effective May 1, 2000. In January 2000, SoCal Edison and PG&E requested permission to participate in the new PX markets, an extension of the termination date from October 2000 to March 2002, and expanded hedging limits. SoCal Edison requested that the limits be increased to the following quarterly levels: 2,000 MW (1st and 2nd Qtr); 5,200 MW (3rd Qtr); and 3,000 MW (4th Qtr).

On March 16, 2000, the CPUC granted SoCal Edison and PG&E's requests to purchase new PX energy products.[14] The hedging limits were revised to PG&E and SoCal Edison's respective "net short positions," or the utilities' total bundled service hourly demand less the amount of generation the utility provides in that hour, through the end of the rate freeze. Specifically, SoCal Edison's limit was increased to 5,000 MW per month, while PG&E's limit was increased to approximately 3,000 MW. PG&E and SoCal Edison subsequently received permission to participate in the PX block-forward market for ancillary services.[15] SDG&E requested similar expansion of its participation in the PX new products markets in July 2000. The CPUC granted this request in August 2000.[16]

In addition, on July 6, 2000, the CPUC authorized SoCal Edison and PG&E to purchase energy in the PX daily and balance of the month block-forward markets, and allowed further increases

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day-ahead market); SDG&E, D.00-96-034(2000)(denied request for limited authority to purchase outside the PX and to use financial instruments outside the PX in connection with an Electric Commodity PBR to be implemented at the end of the rate freeze).

12 According to the California Commission, limitation is necessary to ensure that the IOUs do not over-procure supply, and to reduce opportunities for speculation and the exercise of market power. CPUC Resolution E-3618, issued July 8, 1999.

13 *Id.*

14 Resolution E-3658, issued March 16, 2000.

15 Resolutions E-3666 and E-3672, issued May 4 and June 8, 2000.

16 D.00-08-021 (2000).

in daily (but not monthly) block-forward trading levels, through the end of the rate freeze.[17] On July 21, 2000, PG&E filed an emergency motion requesting authority to enter into bilateral contracts through December 31, 2005. The CPUC granted this request on August 3, 2000, up to the existing block-forward market limits.[18] SDG&E filed a request for similar authority on August 9, 2000.

During the summer of 2000, SDG&E, PG&E and SoCal Edison did not fully utilize their authorized hedging limits. In response to staff queries, PG&E reported that it purchased approximately 1,100 MW in the block-forward market in June and about 1,800 MW in July and August. For the 6-month period ending August 2000, PG&E stated that it hedged approximately 90 percent of its total average load of 40,783,831 MWh, primarily through its own generation (31,857,241 MWh) and block-forward market contracts (4,682,496 MWh). SoCal Edison hedged about 1,750 MW of its 2,200 MW in June and about 3,000 to 3,500 MW of its 5,200 MW limit for July through September.[19] SoCal Edison requested confidential treatment for its hedging strategies and levels. SDG&E responded that it used the authority for a 100-MW transaction for September 1999. SDG&E also pointed out that the block-forward market is not a hedge, as the term is used in trading, and that pursuant to CPUC determinations, it has not used any financial hedges.

3. Economic Regulation of Electric Utilities in Other Western States

In the other western states, utilities are generally regulated by public utility commissions which regulate rates, terms and conditions of service, and which also may issue certificates for the construction of power plants and transmission facilities by investor-owned utilities. These regulatory commissions generally have only limited jurisdiction over cooperatives and none over municipal electricity operations. Open- access programs have been enacted by the states of Arizona (effective on January 1, 2001); New Mexico (phased-in between January 1, 2001, and January 1, 2002); Nevada (retail access delayed since January 1, 1999); Oregon (effective October 1, 2001); Idaho; and Montana (phased in between July 1, 1998 and July 1, 2006). The states of Utah, Washington, South Dakota, Colorado, Nebraska, and Wyoming have not enacted open access or retail competition programs.

B. Environmental Regulation of Electric Utilities

1. Federal Environmental Regulation of Electric Utilities

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17 Resolution E-3683, issued July 6, 2000.

18 D.00-08-023 (2000).

19 *Report on California Energy Market Issues and Performance: May-June 2000,* California ISO Department of Market Analysis, August 10, 2000, p. 20.

The Commission is the primary agency involved in the environmental review of licensing and construction of jurisdictional hydroelectric facilities. In the West a significant amount of the hydroelectric resources are from federally run projects that are not subject to the Commission's jurisdiction. These are subject to federal environmental laws, and their power output can be significantly affected by their need to comply with environmental requirements, such as Endangered Species Act requirements to protect endangered fish in the Northwest. Federal reviews of electric transmission or generation siting proposals may involve the U.S. Army Corps of Engineers if wetlands are involved, the Department of Interior if a historical site is involved, and/or review by the Fish and Wildlife Agency of the Department of the Interior if federal lands or a protected species is involved. In all cases, the project must comply with the minimum requirements administered by the Environmental Protection Agency (EPA) for clean air and water discharge standards, which usually are enforced through a permitting process at the state and local level.

Minimum EPA standards also apply to projects involving the disposition of certain types of hazardous waste and chemicals. Economic and safety review of proposed nuclear power plants (including site safety matters and disposition of hazardous waste) is vested in the Nuclear Regulatory Commission and DOE, respectively, with most other environmental and land use issues reserved to the states or local jurisdictions.

Utility operations are also governed by minimum federal standards for clean air under Title V of the Clean Air Act. Regional air quality plans are developed under EPA supervision and administered by the states. Most important among the standards are ozone, sulfur, particulate, and nitrogen dioxide (NOx), and carbon dioxide emissions.

2. Environmental Regulation of Utilities in California

California environmental regulations are based on: (1) related federal air quality and water quality requirements of the Clean Air Act and the Clean Water Act administered by the EPA; (2) the California Environmental Quality Act (CEQA), (3) several California Clean Air Acts, (4) local air quality standards; and (5) local land use planning and zoning regulations.

Siting Requirements

The siting process for new generation in excess of 50 MW or related transmission facilities is administered by the California Energy Commission (CEC). This review includes a determination of whether the proposed facility is consistent with the state's energy needs and plans and whether it conforms to environmental requirements. The siting process is complex and requires the applicant to select at least three possible sites for the facility, including at least one that is not a coastal site. Certain wetland, conservation, and shore sites are excluded by statute and others have a higher level of protection unless the Commission finds that mitigation will be effective. CEC also must evaluate possible alternative sites that are not listed by the applicant. CEC review involves input from local air quality agencies, which provide a report which is reviewed by the California Air Review Board.

Local jurisdictions such as cities, towns and counties have extensive land use and zoning authority under California law. If a proposed project is inconsistent with a local land use plan or related zoning provision, then a special exception or variance must be obtained at the local level. Individuals and localities are given extensive opportunities to participate in siting decisions. The CEC may override local land use and zoning regulations only if it finds that the facility is required by the public convenience and necessity and that there are not any prudent and feasible alternatives.

On September 7, 2000, the California assembly passed AB 970, to address the immediate need for certain additional generating capacity in the state. AB 970 created an interagency task force of not more than 15 members appointed by the Governor from the various California regulatory agencies, related federal agencies, and local governments to compile and provide all guidance documents and procedures to parties desiring to construct power plants, including best available technology, to provide assistance in processing applications, without compromising public participation or environmental protection, and to help applicants obtain essential inputs such as gas and water supplies, and emission offsets. The bill expires on January 1, 2004, unless extended.

AB 970 also provides for expedited review of new powerplants meeting certain criteria by local clean air districts,[20] and limits these districts in the use of their discretion to require more stringent controls than are required by federal and state minimums in light of the current shortage of generation capacity in California. AB 970 also requires the CEC to establish an expedited process to issue its final certification of any application on the basis of an initial review that shows that there is substantial evidence that the proposed thermal power plant will not cause a significant adverse impact on the environment or electrical system and will comply with all applicable standards, ordinances, or laws. However, all of the information requirements for applications, including compliance with local laws and regulations, must still be included in the application. Further, the CEC may not issue an expedited certificate if it determines, based on substantial evidence, that the project would result in a significant adverse impact on the environment or electric system or does not comply with an applicable standard, ordinance or law. All agencies that would otherwise have jurisdiction are required to submit their comments within 100 days after the application is filed.

[20] Specifically, a proposed powerplant may not emit more than five parts per million of NOx over a 3-hour period, must displace electric generation that has a higher emission rate, must be connected to the grid at a point that urgently needs generation in order to provide reliable electrical generation, and must contract with the ISO for all of its output. Second, the proposal to install a power plant must not be inconsistent with federal clean air requirements, and the proposed power plant must cease operations within 3 years and be modified, replaced, or removed within 3 years with a combined-cycle plant that complies with all applicable laws and regulations.

AB 970 also requires the CEC to institute a proceeding, consistent with the Clean Air Act and California environmental law, for the expedited siting of simple cycle thermal plants, including a determination within 25 days of whether the application qualifies with this portion of the statute. It must make its determination within four months for all projects likely to be in service on or before August 2001. The required certificate will issue if the plant is not a major stationary source or a modification to a stationary source as defined the Clean Air Act, will not have a significant adverse impact on the environment from operations or construction, assures protection of the public health and safety, complies with a federal, state, and local laws ordinances and standards, will cease operations within 3 years and will be modified within 3 years to a combined-cycle plant using best available technology and complies with all laws and ordinances. The plant is also required to obtain pollution offsets or to pay the required environmental mitigation fees.

Emissions Requirements

In California the principal environmental issues involved in electric generation and transmission are related to air quality. The California Air Review Board (CARB) is responsible for developing state air pollution standards from all sources. It oversees the operation of 35 air quality districts within the state. These districts are responsible for implementing state and federal clean air standards and plans, particularly the regional air quality attainment plans required by federal law. Based on these standards, these districts (1) advise the CARB whether a proposed generation or transmission project will comply with the air quality standards for the district, within which it will be located, and (2) regulate the level of pollutants allowed for a given site.

The federal and California standards address six pollutants: ozone (O_3), nitrogen dioxide (NO_2), sulfur dioxide (SO_2) carbon monoxide (CO), fine particulate matter (PM10), and lead. California also has standards for sulfates, hydrogen sulfide, vinyl chloride, and visibility. Local areas which exceed standards for any of these pollutants are designated as "non-attainment" areas, and are subject to increasingly stringent regulations, depending on the severity of the pollution. Areas with air quality better than the federal standards are regulated under Prevention of Significant Deterioration rules, which are intended to keep air quality from reaching unhealthful levels.

Under these rules, new sources of air emissions, including power plants, must have pollution control devices that meet "Best Available Control Technology" and must obtain pollution offsets before beginning operations. In addition, existing power plants must reduce their emissions according to pre-set schedules by retrofitting old plants, adding new controls, or reducing total emissions by purchasing credits from other sources. For older plants, emission control presents a conflict between maximum power production and compliance with the air attainment quality standards in a particular air attainment area. Maximum operations may delay the conversion to more efficient equipment or result in fines if the maximum standards for a given area are exceeded. When power plants produce excessive NOx emissions, this restricts the possible use of emergency generators when generating capacity is short.

All local air quality management districts and air pollution control districts must adopt emission reduction credit banking programs. Within each district, applicants may obtain credits for permanent, real and quantifiable emissions reductions, through facility shutdowns or emissions controls. The districts issue Banking Certificates which may then be traded with other parties at market prices. The program requires that offsets be at a one-to-one ratio or greater. These may then be traded through transfers of Banking Certificates.

The local districts also collect relevant information about offset transactions and publish this information annually. The CARB then compiles this information from all 35 districts and issues a report summarizing these transactions. The CARB's 1999 Report indicates that both the number of NOx transactions and highest price paid for transactions increased substantially since reporting began in 1993. In 1999, the average price paid was $13,884 per ton, or $6.94 per lb. This level had increased dramatically, by the end of the summer of 2000.

5. Why Were Prices High This Summer?

The West experienced unusually high electricity prices during the summer of 2000, with large spikes in May and June, and high average prices throughout the summer. As discussed in Section 3, prices in western markets showed a close relationship to prices in the California PX. Prices in the PX reached as high as $750/MWh during individual hours.[1] Average PX prices were high all summer: $47/MWh in May, $120 in June, $106/MWh in July, and $166 in August. Many end-users were insulated from these wholesale price spikes, by rate freezes in most parts of California, or by traditional utility regulation in other western states. However, others were not insulated from high prices. End-users in the San Diego area were not protected by a retail rate freeze and saw their electricity bills increase several-fold. Some industrial users in the Northwest also experienced price volatility. The three IOUs in California have seen their financial position significantly weakened by these increased prices.[2]

There are three possible factors that can contribute to high prices. This section is divided into three subsections to discuss the effect of each factor on western prices in the summer of 2000:

A. *Competitive market forces*. Prices can be driven up by the normal forces of a competitive market, such as increases in costs of fuel or environmental compliance, or by scarcity of supply.

B *Market design problems*. The rules of market institutions may contribute to prices higher than those that would prevail under competitive forces or with more efficient rules.

C. *Market power exercise*. If sellers possess market power, they have the potential to influence price. If conditions are conducive, the market price can be raised significantly above competitive levels.

In principal, it is important to distinguish among these three factors, because each factor calls for somewhat different regulatory approaches. In the absence of flawed market rules or the exercise of market power, competitive market forces may not call for regulatory action, or may only call for further

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[1] *Price Movements in California Electricity Markets,* California Power Exchange Corporation Compliance Unit (PX September report), September 29, 2000, at 10.

[2] Edison International, SEC 8K Filing, September 25, 2000; "California Utilities' Losses On Electricity Pose Risk, *Wall Street Journal Interactive Edition*, September 27, 2000; Joint Motion for Emergency Relief and Further Proceedings of Pacific Gas and Electric Company, et. al., San Diego Gas & Electric v. Sellers of Energy and Ancillary Services, Docket No. EL00-95-000 *et. al.*, pp. 5-7, October 16, 2000.

monitoring of overall market developments. Market design problems are generally best addressed by changing the market rules. Approaches to dealing with the exercise of market power may vary from compliance actions, to development of new rules, or to broader policy measures.

In practice, one single type of explanation seldom dominates the others, especially under extreme conditions such as those observed in the West over the past summer. Market rule problems with new institutions during a transition period, scarcity or near scarcity supply conditions, and rapid increases in input prices with their associated uncertainty may all be conducive to the exercise of market power. At the same time, these conditions make the detection of the market power exercise more difficult, because they can lead to many of the same results. For example, scarcity can lead to price spikes in competitive markets and rapid increases in input costs can lead to increases in average prices in competitive markets. Policymakers addressing these issues will need to consider all three explanations of high prices.

This staff investigation found that all three factors played some role in the high prices seen in the West in the summer of 2000. The data clearly show that a general scarcity of power in the West and increased costs to produce power were factors causing these high prices. It is also clear that existing market rules exacerbated the situation and contributed to the high prices. The data also indicate some attempted exercise of market power, if the standard of bidding above marginal running cost is used, and some actual market power effects, to the extent that prices, at least in June, were significantly above competitive levels. However, the data do not isolate specific exercises of market power or suggest that the exercise of market power was more important than other explanatory factors.

A. Market Forces: Costs and Scarcity

1. Increased Power Production Costs

As discussed in Section 3, suppliers' costs of generating electricity increased over the summer. The primary causes of the increase were rising prices for natural gas and NOx credits. Natural gas-fired combustion turbine units are usually the marginal units during peak demand periods, so increased natural gas prices can have a substantial impact on the market clearing price. In addition, a combined-cycle gas generator typically emits from 1 to 1.5 pounds of NOx per MWh, so increased prices for emission credits can also affect the market clearing price. Since many of the resources in California are oil and/or natural gas-fired generation, and prices in California closely correlate to prices in the rest of the West, increases in the cost of purchasing natural gas or NOx credits in order to generate power have a significant impact on electricity prices in the West.

Natural gas prices roughly tripled from January 2000 to September 2000 in the West, from less than $2/MMBtu in January to more than $6/MMBtu in September (see Figure 3-10). At the same time, the price of NOx credits increased from about $5 per pound to over $40 per pound (see Figure 3-11). As a result, the marginal operating cost of generation needed to meet peak load in California rose over the summer. As discussed in Section 3, these input price increases drove up the marginal operating cost of a combustion turbine from about $70/MWh in May to more than $190/MWh in August. As a result, market clearing prices that approached the $250/MWh price cap in August may have reflected the true cost of the resource rather than the exercise of market power.

2. Scarce Resources Throughout the West

It is clear that resources were scarce throughout the West during the summer of 2000. Unusually high temperatures and strong economic growth in California, the Northwest and the Southwest resulted in increased demand for electricity. Lower than expected hydropower output and increased unplanned plant outages in California contributed to the general scarcity of power to meet demand. Circumstances in California were exacerbated by increased exports of power from California to other parts of the West.

This section discusses the factors that contributed to a shortage of power in the West. Even in a well functioning market, prices can be driven up when costs increase or supplies become scarce. The following section discusses whether the exercise of market power could have allowed market participants to push up prices by withholding supplies from the market.

The generation shortage began long before the summer of 2000. Growth in demand over time was not matched by increases in generation capacity. Load outpaced generation capacity additions throughout the West in the 1990s. Load in the WSCC region increased by an average of around 3 percent per year, while capacity grew less than 1 percent. This trend resulted in a scarcity of supplies in the region, with the importing areas vulnerable to shortages. California has relied on imports to meet much of its load.

Reserve Margins

Going into the summer, the WSCC's forecast indicated ample reserve margins for the entire WSCC (Table 2-5). However, reserve margins for the California/Mexico (California) subregion (Table 2-6) were slightly lower than those for the total WSCC. The reserve margin for the neighboring Arizona-New Mexico-Southern Nevada (Arizona) subregion was also tight, with forecasts predicting a reserve margin of 13.5 to 13.8 percent for most of the summer (June-August).[3] While the California PX Compliance Unit noted that these were unrealistically rosy predictions,[4] a close reading of the

[3] Western Systems Coordinating Council, *Summary of Estimated Loads and Resources*, May 2000, p. 86.

[4] PX September report at 13-25.

WSCC forecasts shows that they contained stipulations. The WSCC concluded that projected regional capacity margins and reliability would be adequate only if normal temperatures prevailed and normal unplanned generator outages occurred. The forecast stated that, if higher than normal unplanned generator outages were to occur, and an area experienced significantly higher than normal temperatures, or the load in multiple areas peaked simultaneously, portions of the region might need to issue public appeals for customers to reduce their electrical consumption or that other measures might be necessary. [5]

In particular, the WSCC concluded that the southwest portion of the WSCC (New Mexico, Arizona, southern Nevada, California, and Baja California, Mexico) might not have adequate resources to accommodate a widespread severe heat wave or higher than normal generating outages. The forecast raised the specific concern that the California subregion was dependent on contracted supplies that might not be available under emergency conditions. Unfortunately, most of the conditions that posed problems for the region were in place during the summer of 2000.

The higher-than-normal planned and unplanned outages during the summer of 2000 illustrate the impact of the stipulations on the WSCC reserve forecast. The WSCC forecasted no unavailable capacity for the California/Mexico subregion in July and August of 2000, with small volumes of unavailable capacity for May and June of 2000. The same assumptions applied to the Arizona subregion. Factoring in the actual planned and unplanned outages that occurred in the California market (see Figure 2-12), and holding the other assumptions equal, the reserve margins in the California subregion dropped from 26.3 to 17.5 percent for June, from 17.7 to 10.2 percent for July and from 17.4 to 8.98 percent for August. Because the reserve margins were already tight in the Arizona subregion, a small generator outage could drive reserve margins in that region below 10 percent and increase the demand for imports.

As the California PX Compliance Unit has indicated,[6] a significant change in spot prices can be expected when reserve margins drop below established reliability standards. Spot prices spike when reserve margins fall below the 15 to 20 percent range. The connection between reserve margins and price spikes was also observed in the Midwest in 1998.[7]

As noted in Section 2, during May through August of 2000, the Cal-ISO declared 24 Stage One and 14 Stage Two alerts (see Table 2-10). The Cal-ISO declares Stage One alerts when operating reserve levels fall below 7 percent and Stage Two alerts when operating reserve levels fall

[5] Western Systems Coordinating Council, *Assessment of the 2000 Summer Operating Period*, revised May 25, 2000, p. 1.

[6] PX September report at 16.

[7] *Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998*, issued September 22, 1998.

below 5 percent. During 1998 and 1999, when prices were significantly lower than the summer of 2000, the Cal-ISO declared only three Stage One and three Stage Two alerts for 1998 and three Stage One alerts for 1999. The Cal PX has noted a strong correlation between spot prices and low reserve margins this past summer.[8]

Unusually High Temperatures

Temperatures throughout the WSCC were higher than normal for the summer of 2000. Temperatures in the Arizona subregion were particularly high, averaging 3 to 5 degrees higher than normal.[9] The summer of 2000 was also significantly warmer than the previous two years for California. As shown above, in Figure 2-5, western temperatures ranked high relative to other periods over the last 106 years, and particularly relative to the last two summers. For example, the California/Nevada region was ranked 99th out of 106 in June of 2000, compared with 59th and 14th in 1999 and 1998, respectively. Some areas, such as the Southwest, were hot all summer. However, in California high temperatures were more of a factor in May and June than they were in July and August (see Figure 2-4).

Increased Demand

Energy consumption and average daily loads during the summer of 2000 grew rapidly compared with the same period in 1999 (see Figure 2-7). Energy consumption in the WSCC states, excluding California (see Table 2-8), increased by 4.7 percent in May 2000 versus May 1999 while energy consumption in California increased by 5.8 percent over the same period. The increase in energy consumption for June 2000 versus June 1999 was even greater—7.3 percent for the WSCC states, excluding California, and 13.7 percent for California. Within the ISO, average daily peak loads grew by 11 percent in May and 13 percent in June compared with those same months of 1999. California residential energy consumption increased by 8.3 percent in May 2000 compared with May 1999 and 23.8 percent in June 2000 compared with June 1999. Arizona, New Mexico and Nevada experienced even larger increases in residential energy consumption with increases of 36.3, 5.0, and 34.8 percent, respectively for May 2000 over the previous year and 22.3, 11.0, and 27.2 percent respectively for June 2000 over the previous year. These are significant increases in energy consumption from the previous year which can be directly tied to the higher temperatures across the region.

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[8]PX September report at 15, Figure 3, citing a study by Cambridge Energy Research Associates, *The Summer 2000 Spot Electricity Markets Outlook: Divergent Trends n Price Volatility*, July 2000.

[9]PX September report at 19, Figure 5, adapted from information on the NOAA web site.

Forecasts of peak loads made day-ahead were also higher than in 1999 (see Figure 2-8), adding price pressures, even though peak loads ultimately were below peak loads in 1999, primarily as a result of emergency alerts and demand reduction.

Reduced Imports to California

In the past, California has relied upon large amounts of imports from neighboring systems within the WSCC to serve load. However, the amount of imports into California for May through August 2000 were less than the levels for the same period in 1999 (see Figure 2-9). Scheduled net imports to the Cal-ISO fell from an average of 6,294 MW in 1999 to 3,231 MW in 2000; real-time imports from 6,321 MW in 1999 to 4,241 MW in 2000. The trend toward reduced imports was more evident in July and August than it was in May and June; while real-time May 2000 net import levels were 561 MW below 1999 levels. August 2000 real-time net imports were 3,449 MW below 1999.

The amount of imports available into California were reduced because of shortfalls in hydro supply during the summer. Hydro generation from outside California was 8.6 percent below 1999 levels in May 2000, and 23.2 percent below 1999 levels in June 2000 (see Table 2-15).

There appears to be a correlation between the amount of exports and the lowering of the Cal-ISO's buyers cap. When the ISO's buyers cap was lowered from $750/MWh to $500/MWh on July 1, exports rose from 2,995 MW in June to 3,846 MW in July (see Figure 2-10). When the Cal-ISO's buyers cap was further reduced from $500/MWh to $250/MWh on August 7, the amount of exports rose to 4,851 MW in August, an increase of 1,005 MW from the previous month. Thus, the capacity situation in California was tightened by lower supplies entering the state and a large increase in the amount of in-state generation that was sold out-of-state, possibly as a result of the Cal-ISO's buyers cap.

Increased Outages

Another factor that contributed to the supply shortage was the amount of generating capacity that was unavailable because of unplanned outages. In May 2000, outages within the California ISO were only slightly higher than May 1999, but the problem of outages grew worse throughout the summer (see Figure 2-12). By August 2000, 3,391 MW of capacity were unavailable because of unplanned outages compared with 604 in August 1999. California's steam natural gas plants make up 36 percent of the total capacity and are now quite old: 82 percent of these plants are more than 30 years old.[10] As these units are dispatched more frequently due to the shortage of available generating capacity, they are more susceptible to breakdown.

Future Resource Additions

[10] RDI Powerdat database, September 2000.

The problem with California's oil and natural gas generating plants will not be alleviated quickly through the addition of new generating resources within the state. According to the California Energy Commission (CEC), five projects totaling 3,643 MW are expected to be online in 2001-02.[11] An additional 14 projects totaling 8,015 MW are under review by the CEC; however, these projects do not have an anticipated in-service date. Capacity additions throughout the WSCC also lag in the near term. Only 1,521 MW of capacity is planned to be on-line during 2000. The capacity situation within WSCC should improve shortly thereafter when around 23,000 MW of capacity should come on-line between 2001-2003 (see Table 2-3).

Since California started its electric restructuring program, the amount of new generating capacity in California has lagged while load has increased. Only 672 MW of net capacity has been added in California between 1996 through 1999. In the meantime peak load has increased by 5,522 MW over the same period.[12] Load growth rapidly outpaced generation additions, reducing important reserve levels within California.

A major factor in the lack of new generation within California is the complexity of siting generation within the state. As noted by the EOB/CPUC in their report to the governor, "state siting procedures in California are complex and create investor risk because of California's commitment to environmental protection and public participation in the permitting process."[13] The California Environmental Quality Act (CEQA) and the federal Clean Air Act are two of the principal laws that determine where power plants are constructed in California. The CEQA requires evaluation and mitigation of potential power plants before the state allows construction and failure to conduct environmental review can result in CEQA litigation by citizens or local government agencies that can delay, change or eliminate a generating project. In addition, Local Air Districts enforce state, federal and local air quality laws for power plants. The changing California regulatory environment throughout much of the 1990s also created regulatory uncertainty for investors who chose to wait until clear rules were established before applying to build new power plants.

The California legislature's attempt to expedite this process through enactment of AB 970 does little to relieve these difficulties. That legislation gives priority to projects that would have the greatest efficiencies and the least impacts. Thus, while AB 970 centralizes in the CEC determinations that would normally be made by numerous state and local agencies, it does not appear to materially change the substantive provisions governing siting decisions in California.

B. Market Rules

[11] www.energy.ca.gov/sitingcases/projects_since_1979.html

[12] EOB/CPUC report to the Governor on California's Electricity Options and Challenges at 36.

[13] Id. at 38.

The market conditions discussed in the previous section contributed to high prices, but their effects were magnified by the existing market design and some flawed regulatory policies. This section discusses the rules and regulatory policies that appeared to have a significant contributing role in the high prices, as well as some that did not appear to be a factor but that have been commonly assumed to be factors.

Among the factors that appear to have contributed to the recent high electricity prices in western markets, and California in particular, are rules and policies of the PX and the Cal-ISO, and statutory requirements and regulations administered by state and local regulatory bodies. For example, until very recently, SDG&E, SoCal Edison and PG&E were required by CPUC regulations to purchase and sell all of their electricity through the PX. While the three IOUs now have some additional authority to purchase outside the PX, their purchases are subject to an after-the-fact prudence review. These state policies greatly limited the options available to the three IOUs and have created an impediment to their use of forward contracts. Also, state retail rate policies currently prevent consumers from seeing and responding to market prices, and they provide weak incentives for the IOUs to minimize the wholesale cost of electricity once their stranded costs are paid off. In addition, certain ISO and PX rules appear to have contributed to underscheduling of load and generation in forward markets, causing operational problems for the ISO and forcing it to procure energy out-of-market at high prices. These are discussed below.

1. Lack of Forward Contracting

The three IOUs in California were required to purchase their power through the PX with little or no ability to purchase through forward contracts. Requiring the three IOUs to purchase and sell through the PX exposed them to the volatility of the spot market without the ability to mitigate the summer price volatility.

Forward financial contracts for energy potentially can provide IOUs and other load serving entities with a highly effective hedge against high costs in energy spot markets, while providing both buyers and sellers with a greater level of price certainty. Moreover, for generators that are otherwise able to exercise market power in energy spot markets, such contracts can help to mitigate the market power of the generators that hold them. Thus, forward financial contracts offer the potential to reduce both the cost impact of price spikes on consumers' bills, and the incidence and magnitude of the price spikes that occur.[14]

[14] The Market Surveillance Committee and the ISO's Division of Market Analysis have reached similar conclusions. See, *e.g.*, *An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets*, by Frank A. Wolak, *et al.*, September 6, 2000, pp. 6-11, and *Report on California Energy Market Issues and Performance: May-June 2000,*

Properly structured forward contracts can benefit consumers by providing load serving entities with the ability to lock in a fixed price for a fixed quantity of energy well in advance of the actual consumption of that energy. This means that a load serving entity need only face spot prices to the extent that its actual energy purchases differ from its forward market purchases. Indeed, if a load serving entity's actual purchases match its forward market purchases, it can achieve both a perfect hedge against high spot prices and the benefit of complete price certainty in the face of spot price volatility. Of course, holding forward contracts does not guarantee that consumers will incur lower total energy costs. These costs ultimately will depend on the relative level of prices in the forward and spot energy markets.

Forward financial contracts also help to mitigate generation market power in energy spot markets. For example, consider a generator with market power that holds a contract for differences with a load serving entity. Such a contract requires the generator to compensate the buyer for the difference between the energy spot price and the contract's strike price when the strike price is lower than the spot price, and requires the buyer to compensate the generator when the strike price is higher. Holding this type of contract reduces the incentive of the generator to raise spot prices because any increase in spot prices will cause its payments to the buyer to increase (or its receipts from the buyer to decrease). Thus, to the extent that the majority of its supply portfolio is committed under contracts for differences, the generator's incentive to exercise market power in the spot market will be reduced or even eliminated. Similar results can be shown to hold for generators that hold other forms of financial contracts as well as forward physical contracts. It must be emphasized, however, that forward contracts serve only to mitigate market power in spot markets; the market power that a generator may have in forward markets will be unaffected by the forward contracts that it holds. Nevertheless, market power tends to be found less in forward markets than it is in spot markets, because forward markets provide energy purchasers with more lead time and therefore more options. Indeed, with sufficient lead time, the options available to purchasers in the forward market can include the construction of new generating units.

Until recently, CPUC regulations placed strict limits on the options available to IOUs to enter into forward contracts. Specifically, prior to August, the CPUC limited the forward contracts available to PG&E, SoCal Edison and SDG&E to block forward contracts purchased through the PX that provided for delivery of energy up to 12 months hence. Also, the regulations strictly limited the quantity of energy that each IOU could obtain through forward contracting. However, since August, actions by the CPUC and the state legislature have provided the IOUs with an expanded array of PX energy products and with the authority to enter into long-term bilateral contracts with entities outside the PX. Restrictions on forward contract trading levels remain in place as well as after-the-fact prudence reviews which dampen a purchaser's incentive to buy forward.

California ISO Department of Market Analysis, August 10, 2000, p. 6.

During and prior to the summer of 2000, the IOUs did not fully utilize even the limited authority they had to enter into forward contracts. There are perhaps several reasons for this. First, the standard products available through the PX block forward market may not have met the specific needs of the IOUs. For example, these products are defined only for a limited set of fixed hourly periods (peak, super-peak and shoulder-peak) within a given calendar month. Second, because the standard contracts did not provide a full range of hedging features, they may not have offered the level of insurance against price spikes that the IOUs sought. Third, the prices for the block forward contracts may have appeared high relative to the IOUs' forecasts of spot prices for the summer of 2000. Indeed, by the time the IOUs received authority to increase their forward market trading levels, forward market prices had already increased, probably in response to the early spot market price spikes. Finally, the IOUs may have feared that the CPUC would declare their forward market purchases to be imprudent if spot prices turned out to be lower. In addition, because SDG&E was allowed to easily pass through to retail customers its energy and ancillary services costs, it may not have had a strong incentive to aggressively pursue cost reductions through forward contracting.

The restrictions on the ability of the IOUs to enter into forward contracts have denied the IOUs the opportunity to adequately insure themselves against high energy spot prices. Also, because forward contracts can help to mitigate generation market power in energy spot markets, price spikes during the summer of 2000 have probably been larger and more frequent than they otherwise would have been if the level of forward contracting had been higher.

2. Demand Responsiveness

In well functioning competitive markets, both suppliers and consumers are able to see and respond to market prices. Indeed, this is what allows competitive markets to achieve the efficient outcomes for which they are well noted. However, in electricity markets, such as those of California, consumers often must make their consumption decisions without knowledge of the true market price of electricity. In addition, some utility purchasers of electricity, such as SDG&E, may not always have strong incentives to minimize the wholesale cost of the electricity that they purchase for their retail customers. This lack of demand responsiveness can, at times, lead to excessively high prices.[15] It can also have important implications for the Commission's regulation of wholesale power markets.

To be effective, prices must accurately reflect the cost of supplying electricity at a given time and place, and they must be communicated to consumers in a timely manner. In California, for example, retail customers generally are not provided with accurate and timely price signals. This is due

[15] See also, *An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets*, by Frank A. Wolak, *et al.*, September 6, 2000, pp. 10-13, and *Report on California Energy Market Issues and Performance: May-June 2000,* California ISO Department of Market Analysis, August 10, 2000, p. 6.

in part to the retail rate freeze that was applied to the IOUs as part of the statewide restructuring. The retail rates of PG&E, SoCal Edison and SDG&E were frozen at the time of restructuring to ensure that retail customers would not pay rates that exceeded the rates paid before deregulation. The rate freeze was designed to operate in conjunction with the recovery of the utilities' stranded costs. Specifically, AB 1890 provided for recovery of stranded costs through a Competition Transition Charge (CTC). The CTC surcharge cannot, in conjunction with PX market prices, exceed the rate freeze levels. This means that, to the extent that PX prices are high, CTC recovery is slower. Consequently, if customers reduce their demands, their rates do not fall; the utilities simply recover their stranded costs at a faster rate. Both the CTC and the rate freeze are limited in duration to the earlier of March 31, 2002, or until stranded costs are fully recovered for each IOU.

SDG&E completed its recovery of stranded costs in 1999 and the CPUC lifted its rate freeze in July 1999. With the end of the rate freeze, SDG&E was allowed to pass on its wholesale costs of power directly to its customers. Consequently, SDG&E customers felt the full impact of the wholesale price increases that were experienced in the summer of 2000, when their electricity bills more than doubled. However, because these customers did not see the rate impacts until they received their bills, they had no practical way to respond in the short term to the high prices. Also, without time-of-use metering, they were unable to reduce their bills by moving consumption to off-peak periods. Furthermore, SDG&E itself may have had little incentive to minimize its purchased power costs given that it could simply pass through the costs to ratepayers, subject only to the possibility of a prudence review by the CPUC.

By contrast, PG&E and SoCal Edison have not completed their stranded cost recovery and therefore remain subject to the retail rate freeze. Consequently, these utilities' customers were fully insulated from the price increases of the summer of 2000, and clearly had no incentive to modify their consumption patterns in response to the increased costs. However, because PG&E and SoCal Edison were unable to pass through the increased wholesale costs to their customers, they likely had a much stronger incentive than SDG&E to minimize these costs, because any cost savings realized can be applied as an offset to their CTC costs. However, neither of these companies had much ability to minimize their costs because they were largely required to buy in the spot market.

It should be noted that available evidence suggests that customers that had direct access to wholesale markets this summer did indeed change their consumption patterns in response to the price increases. Based on discussions during this investigation, there is evidence to suggest that some load reduced purchases during peak periods and increased purchases off peak.

The fundamental problem created by unresponsive demand is that, during periods of tight supply, prices can rise far above competitive levels. The reason is as follows. In a competitive market, if demand is low relative to the available generating capacity (such as during off-peak periods), the market clearing price will approximate the marginal running cost of the most costly generator operating. This is true even when demand is unresponsive to price, as long as the market includes many owners of generation competing to serve the limited demand, and none of these generators has locational market power. However, these same generation owners will discover that they have considerable market power when demand is both unresponsive to price and at such a high level as to require the ISO to place virtually all available generating capacity in operation or on reserve in order to meet demand reliably.

This is not to say that competitive prices should never rise above the marginal running cost of generation. When supply is scarce relative to demand, competitive prices will rise to a level that reflects the value that the marginal consumer places on additional consumption. This additional increment above marginal running cost is referred to as the "scarcity rent." However, market prices in electricity markets like those in California cannot be expected to settle at this level if retail consumers do not have the ability to see these prices and to make known to the market, through their purchasing decisions, the value that they place on marginal consumption. Indeed, in the absence of demand responsiveness, prices in California and in markets elsewhere frequently rise well above this competitive level at times when demand is high and capacity is scarce.

The only alternative facing a system operator in the absence of demand response may be to ration demand through administrative load reductions. This is exactly what happened in California last summer, when a total of 38 emergency alerts were called. These administrative procedures succeeded in reducing demand without curtailment of firm load, which suggests that load does indeed have the ability to reduce its consumption. But it does appear difficult to convert these reductions from an administrative basis to a market one. Under the reliability rules, interruptible load cannot be required to reduce its consumption except under emergency conditions. Thus, as long as firm load is maintained, load may have only limited incentives for price-based reduction of consumption. It appears difficult to develop a large amount of demand response, but the reasons appear to be institutional more than physical.

3. Underscheduling

At present, the PX has a $2,500/MWh price cap[16] and the Cal-ISO has caps of $250/MWh for energy and ancillary services and $100/MWh for replacement reserves. The PX's higher energy price cap has not limited energy prices in the PX. Instead, as noted in the San Diego order, the ISO's cap has effectively limited the price of generation sales in the PX day-ahead and hour-ahead energy markets.[17] Buyers never offer to pay more in the PX market than the ISO's maximum purchase price, since they may still buy at the ISO's cap in the real-time market if their bids are not accepted in the PX.

[16] The PX price "cap" is actually a practical limit imposed by the market software requirements, not a regulatory restriction on bidding or pricing.

[17] San Diego Gas & Electric Company, *et. al.*, 92 FERC ¶ 61,172 (2000).

Specifically, the net cost to load to buy in the ISO's real time energy market cannot currently exceed \$350/MWh (i.e., \$250 for energy and \$100 for replacement reserves). Thus, loads will not offer to pay more than \$350/MWh for energy in the PX's forward market, and the PX energy price will not exceed that level. These restrictions on price helped create incentives for both buyers and sellers to underschedule load and supply in the day-ahead market.

The amount of underscheduling has tended to increase substantially during high demand periods. A major reason appears to be that the amount of supply offered into the PX markets during high demand periods is often substantially less than forecasted demand. Data presented in Section 2 indicate that the day-ahead schedules in the PX consistently fell below forecast loads whenever loads were above 35,000 MW, and that the load level where this occurred decreased in July and August. Information in Section 3 shows that the proportion of supply below \$100 in the PX was reduced through the summer as the price cap was reduced. The total amount of supply offered in the PX does not appear to change much over the summer. The California PX states that little additional supply has been offered into the PX Day-Ahead market at any price above \$100/MWh, especially when the ISO's load forecast exceeds 35,000 MWh. For example, on July 31, 2000, in hour 16, total supply offered into the PX day-ahead market at any price was less than 35,000 MWh, while the ISO's load forecast was over 45,000 MWh.[18]

As a result, load and generation underschedule in the PX's forward markets and then appear in the ISO's real-time market. Extensive underscheduling creates operational and reliability problems for the Cal-ISO, and has required it to procure energy out-of-market at high prices.

In an attempt to address the operational problems and reduce the incentives for underscheduling, the ISO modified its practices for procuring replacement reserves in May 1999. Specifically, the ISO now procures a day in advance enough replacement reserves to match its estimate of underscheduled load—that is, the difference between its own forecast of real time load and the amount of energy scheduled in the forward markets. The ISO says that procuring additional replacement reserves increases the likelihood that sufficient generation will be available to reliably meet the load that shows up in real time. As an incentive to discourage underscheduling, the ISO charges the costs of the replacement reserves to unscheduled load that shows up in real time and to scheduled generation that fails to produce in real time.[19]

However, the modified replacement reserves policy has not reduced the amount of underscheduling. Indeed, underscheduling has increased, especially during high demand periods. For

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[18] PX September report at 44.

[19] See, *AES Redondo Beach, L.L.C., et al.*, 87 FERC ¶ 61,208, (May 26, 1999)

example, in June as much as 21 percent of real time load was not scheduled in advance.[20] A major reason for this phenomenon is that the policy creates conflicting incentives. On the one hand, the policy does discourage buyers from underscheduling, by charging the costs of replacement reserves to unscheduled load. However, the policy also encourages generators not to offer energy in the forward market (especially during periods of high demand), but instead to sell their capacity as replacement reserves. That is because by doing so, the generator can receive a payment for replacement reserves in addition to a payment for selling energy in real time. (During periods of high demand, generators selected to provide replacement reserves are likely to be called on in real time to produce energy. The policy encourages generators to bid less into the PX as load increases, by increasing the probability that all replacement reserves will be used for energy and hence the expected opportunity cost of not deferring supply until the hour-ahead or real time markets.)

As noted by the MSC, because the ISO requires all forward schedules to be balanced, load and generation are equally underscheduled. Underscheduling arises largely because loads and generators disagree about the appropriate forward price of energy. In effect, underscheduling occurs because loads are trying to protect themselves from higher prices in the forward market, while generators are trying to protect themselves from lower prices in the forward market.

Clearly, substantial underscheduling creates operational and reliability problems for the ISO as the grid operator. The effect of underscheduling on energy prices, however, is less clear. On the one hand, the ISO has incurred costs to procure replacement reserves and to make out-of-market purchases at high prices in response to underscheduling. On the other hand, attempts by load to reduce underscheduling by procuring more energy in the forward markets would likely put upward pressure on forward market prices. In sum, underscheduling had no clear impact on this summer's prices.

4. Exports/Imports

Exports increased through the summer along with reductions in the price cap, but there are many possible reasons why this might have occurred, including prior commitments by generators, increased opportunities in the Southwest where weather remained extremely hot, reductions in the overall WSCC level of hydro generation, and off peak pumping requirements for hydro. These exports have the effect of reducing the supply of in-state generation and limiting the amount of such generation bid into the PX. In the summer of 2000, these increases in exports were not compensated by increases in imports, and the net imports into California were reduced.

Several concerns have been raised about the reduction in net imports. The first concern is one of reliability, because the reduction in scheduled imports contributed significantly to the problem of

[20] *Report on California Energy Market Issues and Performance: May-June 2000,* California ISO Department of Market Analysis, August 10, 2000, p. 26.

underscheduling. The ISO needed to purchase additional imports for real time, either through replacement reserves or out-of-market purchases at the last minute, contributing to the high incidence of emergency alerts and concerns of maintaining the reliability of the system.

The second concern is that generators exporting power were gaming the system in order to increase prices. By selling to entities outside California, who may be the same entities who supply imported power in real time, the increased exports decrease supply in day ahead and hourly energy markets and increase prices. Supply then becomes available in replacement reserve markets at the ISO, or as out-of-market purchases in emergencies. Out of market purchases were not large (less than 1 percent of energy costs), but replacement reserve purchases were very high on certain days in the summer (see Section 3). In one sense, this is not gaming, since there are no administrative rules on the amount of capacity that must be provided to meet load as there are in the eastern ISOs. Loads are required to bid into the PX, but there is no capacity penalty imposed if corresponding supply does not bid into the PX. The concern seems to be that megawatts are exported to the very same entities who then sell the megawatts back in real time at high prices. Several generators reported contracting a significant proportion of their supply forward outside of California, and the buyers of that power may have exported it back to California at some later date. One marketer, who is reported to have contracted for power from California generators at attractive prices before the summer, exported power back as replacement reserves at high prices during emergency conditions in California.

These exporting practices are permitted under the rules and are not necessarily a market power problem. It may simply be the normal working of a market where sellers are maximizing profits in a competitive market, where sellers or buyers see an opportunity at one time, take an option, and exercise it at a later date. It becomes a problem if it is associated with a pattern of withholding resources from the market in order to drive up prices. For example, if a large seller outside California were able to influence the price of power in the West by acquiring power from California, withholding power from the market at a critical time, and selling the power back to California. As such, it is part of the overall issue of market power and scarcity in the West, discussed in the next section.

5. Auction Rules

Currently, the Cal-ISO and the PX use a single-price rule for establishing real time energy prices. That is, the market-clearing price (which is based on the highest accepted bid) is paid to all accepted sellers, including those who bid less than the price. To prevent future price spikes, some have proposed an alternative pricing rule—paying each accepted seller its bid, rather than the market-clearing price. Buyers would then pay a price reflecting the average of the accepted sellers' bids. Proponents of the pay-as-bid rule argue that consumers would pay less in total during high demand periods, on the grounds that consumers would pay less than the highest accepted bid to suppliers who bid less. However, generators are not likely to bid under a pay-as-bid rule in the same way as under the single-price rule. Sellers bidding below the market-clearing price will receive that price under the single-price rule, but they will receive only their bid under the pay-as-bid rule. So generators will generally submit higher bids under a pay-as-bid rule. In sum, it is not clear whether a pay-as-bid rule would have the effect of lowering consumers' bills.

C. Market Power

The previous sections have discussed the factors that contributed to an electricity shortage this summer and the effects of problems with market rules. This section discusses the issue of market power in the context of scarcity and considers whether the apparent shortage arose because of withholding and hence whether the high prices in the West were the result of the exercise of market power. Market power is the ability of a seller to influence market outcomes, especially the market price for a sustained period. Sellers exercising market power use this ability to raise the market price above competitive levels, either by physically withholding some of their capacity from the market, or by offering their capacity at prices above competitive levels. During periods of supply scarcity, the market price naturally rises and even firms with relatively small market shares may possess significant market power. However, as the supply becomes more scarce, it becomes more difficult to isolate the effects of scarcity and market power on the market price.

Market power, like scarcity, is a matter of degree. It is important to recognize that, in practice, the issue of market power is not a simple, all-or-none question, but turns on the magnitude of the market power impact on price and its consequences. In times of scarcity, this impact is potentially very large, but it may be very difficult to separate from scarcity effects that can also be large and the duration of the impact of market power may be relatively short-lived.

Significant market power abuses that violate market rules need to be dealt with directly, but market power in a newly developing market may be magnified by flaws in market rules. The best approach in these cases may be to change the rules in order to mitigate the impact of market power exercise. Mitigation in the form of rule changes may be appropriate even in the absence of findings of market power exercise by specific sellers or buyers, if there are clear incentives for its exercise, and there are potentially large impacts that cannot be adequately separated from the effects of scarcity.

As discussed below, there is evidence suggesting that sellers had the potential to exercise market power during this past summer. However, the evidence available and analyzed during this investigation, to evaluate whether there were actual exercises of market power, is inconclusive. A considerable amount of data on individual bidding patterns and individual plant performance was obtained and reviewed in the course of this investigation, but was not sufficient to make determinations regarding exercises of market power by individual sellers. Further study of high-priced bidding by individual firms or periods when individual generators were not running would be needed to substantiate any charges of market power abuse.

1. Measuring the Effects of Market Power on Price

During periods of high demand and tight capacity, prices would ordinarily rise as a result of basic competitive market forces and real scarcity. However, conditions of tight capacity can often create market power, especially when demand is insensitive to price. When demand is inelastic and approaches capacity, a seller with a relatively small amount of capacity can often begin to influence the market price. It can sell most (if not all) of its output even if it asks for a price higher than what other sellers are asking. The seller may lose some sales by asking a higher price, but these lost sales revenues are more than made up by the higher prices on the output it produces. Thus, while the combination of high demand and tight capacity would ordinarily cause prices to rise due to competitive market forces, they may also create market power that causes prices to rise even higher. From a public policy perspective, the desirable outcome is a competitive price increase, not the higher price increase caused by the exercise of market power.

When market power is exercised, the market clearing price exceeds the price that would have been set under competitive conditions. It is important to note that a generator's true marginal cost is the generator's opportunity cost of selling into a particular market. That is, the next highest value of the resource. If the running cost of a unit is $40 per MWh, but that unit is physically able to sell into a market in which the price would be $80 per MWh if that generator participated in that market, then the opportunity cost of selling into another market is $80 per MWh. As long as the generator bids its true opportunity cost into a market, it will never receive less than the true value of its output.

In order to estimate the degree to which market power is being exercised, the supply curve for a particular hour would have to be reconstructed replacing the bids received with the marginal cost of each bidding generator. The effect of market power on the price would be the difference between the actual market clearing price and what the market clearing price would have been if all the generators had bid their true marginal cost. The Market Surveillance Committee (MSC) of the California ISO has performed such an analysis. The MSC estimated a significant degree of market power being exercised in California markets for the period October 1, 1999, to June 30, 2000. They estimated that prices for non-must-take energy over the entire period were 36.3 percent higher than they would have been under competitive conditions. For the last month of the sample, June 2000, they estimated that prices were 64.6 percent higher than they would have been under competitive conditions. The highest previous monthly market power index was in June 1998, when prices were estimated to be 39.9 percent higher than they would have been under competitive conditions.[21] These findings certainly suggest that market power was exercised in June by the standard of short run marginal costs. Average prices in August were higher than June. However, as discussed in Section 3, costs were also much higher, so it is unclear whether, or to what extent, market power appears to be a continuing concern. The MSC has not yet completed an analysis for July and August.

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[21] The monthly market power index is the percentage increase in monthly wholesale energy revenues relative to monthly revenues under the perfectly competitive benchmark. *MSC Report on June 2000 Price Spikes*, September 6, 2000, p. 17.

2. Demand Conditions

The degree to which the market price will exceed the marginal cost of production depends not only on the supply-side factors discussed above, but also on the demand responsiveness. For any given concentration level, the less responsive (elastic) the demand the more the market price can be raised above marginal cost.[22] Thus the less elastic the demand, the greater the cost to consumers of an exercise of market power. In California, as in other states, demand changes from hour to hour, but not typically in response to hourly prices. Nevertheless, it is clear that demand can respond to conditions, as the difference between peak forecasts and actual loads (see Section 3) suggests. During emergency periods, interruptible customers have their demand reduced and voluntary reductions do occur in measurable amounts, in response to ISO interruptions of loads and public appeals for conservation. The difficulty is that the demand response is driven by administrative directive, not by market prices.

3. Market Power and Scarcity

In both the PX and ISO, all generators supplying energy receive the market-clearing price, which is the highest accepted bid to supply energy. During periods of scarce supply, the market-clearing price will greatly exceed the marginal running costs of most of the generators supplying energy.[23] Those generators with low running costs will receive a significant profit from the output of their units. The high price then serves as a signal to potential entrants that there are profits to be made. High prices during periods of supply scarcity are a normal feature of a properly-functioning market.[24]

It is difficult to separate scarcity from market power. As stated above, during periods when electricity becomes more scarce, the price naturally increases. However, during those same periods the ability and incentive to exercise market power increases. The ability to exercise market power (raise price) increases because the market is clearing in the steep (inelastic) portion of the supply curve, thus a slight reduction in output will significantly increase the market-clearing price. The incentive to exercise market power increases because the payoff becomes much higher. Any generator whose bid is accepted will receive the higher market-clearing price for all the energy it provides for that hour.

[22] For example, a measure of market power in a monopoly, the price-cost margin or Lerner Index ((Price - Marginal Cost)/Price) is equal to -1/elasticity of demand.

[23] In fact, during a period of true scarcity, when demand exceeds supply even the unit setting the market-clearing price will receive a profit, or scarcity rent, since the price will naturally increase in order to equate supply and demand.

[24] Especially in a market with little demand elasticity.

For an example of true scarcity, the California ISO DMA reports that during June 2000, there were 27 hours when the available supply within the ISO was less than the system demand.[25] For those hours, the average cost of procuring real-time energy was $709/MWh.[26] During a period of true scarcity, any firm that can sell energy into the ISO real-time market has market power.

In addition, during June 2000 there were 106 hours when the available supply was between 100 percent and 110 percent of the system demand. For those hours the average cost of procuring real-time energy was $324 per MWh.[27] Even considering the increase in marginal cost of operating gas-fired generators in Southern California, a price of $324 per MWh exceeds estimates of the marginal cost of the last unit supplying energy. In June, the highest marginal operating cost was about $160/MWh.[28] As noted in Section 3 of this report, it was not until August and September that the combination of high natural gas and NOx credit prices pushed the running cost of gas turbine units near that level.

4. Methods of Exercising Market Power

A generator could exercise market power through either economic or physical withholding. In the case of economic withholding, a generator would submit bids in excess of its opportunity cost in order to raise the market clearing price. In the case of physical withholding, the generator would not supply all of its available energy in order to increase the market-clearing price. In that case, by withholding lower cost output, higher cost units whose bids would not otherwise have been accepted would set the market clearing price. All suppliers whose bids were accepted would then receive the inflated market-clearing price. As long as the gain from the higher price exceeded the lost profits from the foregone output, withholding output would be a profitable strategy.

However, as noted earlier, determining physical withholding from real unit outages that occur during periods of high demand is difficult. This determination is made particularly difficult in the western environment by the presence of hydropower, must take contracts, and severe environmental compliance limitations. In each of these categories, it is difficult to determine the relevant capacity,

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[25] Department of Market Analysis, California ISO. *Report on California Energy Market Issues and Performance: May - June, 2000*, p. 51.

[26] The total cost includes both capacity and energy payments, since many of the units that provide energy also provide reserve capacity.

[27] Department of Market Analysis, California ISO. *Report on California Energy Market Issues and Performance: May - June, 2000*, p. 51.

[28] Eric Hildebrandt, *Market Analysis Report*, California ISO Department of Market Analysis, September 2000.

since the amount of energy the facility can produce is limited by various factors, not by the physical capacity of the unit. From conversations with the ISO staff, we have learned that hydro facilities and must take contracts are treated on an "as bid" basis, so that the amount of energy bid is taken as the indicator of the power available from the unit in any given hour. These facilities will often appear underutilized and much of the capacity will appear available when measured against the total physical capability of the unit.

Because of the difficulty in assessing a firm's true opportunity cost of selling into a market, economic withholding is even more difficult to assess than physical withholding. Generators are maximizing the profits from a portfolio of generation units. There are many markets into which they can sell. They face environmental, reliability, technical and regulatory constraints. For example, generation units have different start-up costs and ramp rates. Since the bids the units submit to the PX and ISO (through their scheduling coordinator) are composed of capacity and energy but not other costs such as startup, they cannot bid their full set of cost components, so they may "average" some of the costs associated with ramping their units up or down into their bids. It is not clear what constitutes a reasonable averaging and what does not.

A generator that is producing less than its capability during a period when the price is greater than its opportunity cost would appear to be engaging in physical withholding. It is not always clear, however, what separates withholding output in order to raise price from withholding output due to environmental, reliability, technical or regulatory constraints. For example, for a unit that is slow to ramp down, the optimal running plan may be to begin to reduce output (withhold) earlier in the day than for a unit that can be quickly ramped down. For another example, a unit may only be able to run for a fixed number of hours during the summer due to environmental constraints. What appears to be withholding (not running the unit when the market price exceeds the marginal running cost) may be simply the result of the generator trying to maximize the value of the unit's output for those hours it can run.

5. Evidence from Summer of 2000

One method of withholding output would be to call an unplanned plant outage. An increase in unplanned outages shortly before or during price spikes would be an indicator of physical withholding. As noted in Section 2.3, the amount of capacity unavailable due to unplanned outages was 2,787 MW greater in August 2000 than it had been in August 1999. Given the significant cost increase of the marginal units and their associated bid price increase, the absence of 2,787 MW significantly increased the market-clearing price. Higher prices are to be expected during a period with significant capacity unavailable due to outages; they are the result of an inward shift of the supply curve at the time of the outage. As shown in Table 2-14, however, the strongest correlation was between outages (unplanned and planned) and the next day's price rather than the price in the day of the outages. The outages would then be lower on the day of the high prices, than they were on the previous day. High prices in the periods after a significant amount of capacity becomes unavailable would indicate a market reaction beyond the direct effect on the supply. While the reaction could be a competitive attempt to reduce outages in anticipation of tight conditions, it is also consistent with an attempt to exercise market power by driving up prices for the next day and then making the unit available in time to receive those high prices.[29]

If attention is focused on the thermal units that have the greatest ability to respond to price, data from the control areas in the WSCC seem to show that only 5 to 7 percent of the non-hydro generation resources went unused at peak times. This suggests that the magnitude of any physical withholding of available capacity was not large for these units.

Firms could also exercise market power through the bids they submit to the ISO and PX. As described in Section 3, the bid curves offered in the PX change their shape through the summer as the price cap lowers. The proportion of bids under $100 decreased during the summer, so that firms were changing their bidding behavior and increased the price at which they would offer any given amount of supply. However, the change in behavior was exhibited by all categories of participants, so it is as likely to be a response to increased costs as it is to be intentional behavior by any individual firms or groups of firms to raise the lowest price offered to compensate for reduction in the price cap.

As noted by the above, the price responsiveness (elasticity) of supply significantly influences the effectiveness of either type of withholding. If the market supply is highly responsive to changes in price, then any attempt at economic or physical withholding will not be effective, since there will be significant supply at the margin to respond without causing a significant increase in price. An indicator of an effective economic or physical withholding strategy would be if those units that consistently set the market-clearing price were able to decrease the supply elasticity through their bidding behavior. The PX Compliance Unit estimated that the average supply elasticity of the units clearing the market for those hours in May through July 2000 when the market-clearing price exceeded $100 per MWh was actually 24 times greater than the overall supply elasticity.[30] As a result, the entry of supply at high prices may have increased the elasticity of supply in these ranges, making the exercise of market power more difficult over these load ranges that it otherwise would have been. Staff was able to observe this phenomenon in the individual participant bidding curves. Some bidders bid consistently at high levels, submitting bids that varied even though the average price bid was high. Other bidders submitted bid curves that included a large amount of supply at low prices and only a very small amount at high prices, making the bid curve very steep for a small proportion of their submitted supply. Bidders in the former category will tend to make high-priced supply more elastic. However, they also have the effect of

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29 Specific examples of this practice have been noted in the England and Wales pool by several observers. For example, see David Newbury, *Power Markets and Markets for Power*, and Frank Wolak and Robert Patrick, *England and Wales Electricity Market*, February 1997.

30 California Power Exchange Corporation Compliance Unit. *Price Movements in California Electricity Markets, Analysis of Price Activity: May-July 2000*. September 29, 2000, pp. 59-61.

shifting total supply upward, so they will also tend to raise the price at lower load levels compared to bidders who submit only a small proportion of supply at high prices.

6. Market Power in Context

It is important to evaluate the impact of market power in the context of two conditions discussed in the earlier sections: scarcity and market rules. In the short term, when supply becomes very tight and demand is unable to respond, the price discipline of a normal competitive market is greatly diminished. The effects of scarcity and market power in these circumstances are very similar: high prices, a seller's market with few or no restraints on sellers, and few or no options for buyers. In an ideal world with no market power, these prices would signal scarcity and the market would correct itself. But the past summer in the West was not an ideal world. Buyers had essentially no short-term options and few longer-term, forward ones. Without better forward markets, even true scarcity signals would not get effectively conveyed until close to real time, leaving little room for the development of a more stable overall market.

Market power can compound the effect of scarcity, because it will distort normal market signals. Sellers have the incentive to raise prices to inelastic buyers when supplies are anticipated to be tight, and the result can be prices above competitive levels that appear sooner than they would in a workably competitive market where prices are set by short-term marginal opportunity costs. Frequently, these prices may be the work of a competitive market. However, at least some of the June price spikes appear to be attributable to market power, and high bids observed in PX and replacement reserve markets during this investigation provide further indications that above marginal cost bids can be sustainable.

Market rules can provide some substitute discipline if normal market processes break down, at the risk of distorting genuine market signals. But markets designed with overly complex rules and decision procedures can make matters worse, if they give sellers misplaced incentives and the means to act on them. For example, rules that provide incentives to shift supplies from the day-ahead spot market to even shorter-term hourly or real time markets can adversely affect the ability of the ISO to manage the market reliably in real time. Although the price impact of such shifts is uncertain, the effect is to move supply to a market where demand is even less responsive than in the day-ahead market, restricting buyer options and potentially increases any market power the seller may possess. Without prospects of greater demand response in close to real time, these types of problems may be very difficult to manage through purely market incentives, and non-market rules may be needed.

If higher than competitive prices are sustained for a long enough period of time, price restraints, capacity requirements, rules requiring greater forward contracting, or some other market intervention may be needed. However, policy makers need to factor in increases in input costs, unavoidable limitations on siting generation and transmission costs and other true costs or limitations in crafting workable market rules that assist market development rather than impeding it.

D. Conclusion

As noted at the beginning of this section, competitive forces, flawed market rules and, to some extent, market power contributed to the unusually high prices the past summer. These results seem to suggest that some change in market rules is required. Additionally, some further steps during a "transition" period to 2002, when new capacity will be available, may also be necessary. Options to address these conclusions are provided in the following section.

6. Policy Options

This section discusses some of the options available to the Commission or state agencies, with encouragement by the Commission, to correct the conditions that led to the unusually high and volatile prices in the West during the summer of 2000. Those conditions were: a general shortage of generation throughout the West, an over-reliance on spot market purchases by the IOUs in California, insufficient demand responsiveness to price, and a highly politicized process for setting price caps for the Cal-ISO. The options are summarized below first and then discussed in the following section.

To encourage investment in new generation:

- Adopt policies that encourage and facilitate the investment in new generation. Tight generation resources were a major factor contributing to high prices. Easing local siting approval processes in California could encourage more investment and ultimately bring on more electricity supply. At the federal level, the Commission's wholesale price policies have an important effect on investment decisions and should be designed to create incentives to spur new investment in generation and transmission.

To remedy the over-reliance on spot market purchases:

- Eliminate the requirement that the three California IOUs must buy and sell through the PX. This can be implemented by the Commission (1) requiring a change in the eligibility provisions of the PX tariff or (2) changing its policies applicable to wholesale spot markets.

- Require the IOUs to hedge and forward contract through the PX and bilateral transactions. This can be implemented either by the CPUC or by the FERC.

- Require all in-California thermal generation capacity to be bid into the forward California markets. This option might increase the amount of capacity available in the forward markets.

To provide more demand response to wholesale prices:

- Encourage California to implement policies to increase retail demand responsiveness to price. The Commission has no authority over retail rates in California; however, California may undertake retail market reforms that will greatly benefit wholesale markets. Competition among energy service providers for the retail load of the IOUs would create strong downward pressure on the price of energy in California. Just allowing large retail consumers to face the price in the wholesale market would provide more demand responsiveness to the wholesale market. If state policy is to allow load serving entities to pass through the costs of energy and ancillary services directly to retail customers, then those customers should be given some way to respond to those prices. If state policy continues to regulate retail service by the IOUs, then the IOUs should be given strong incentives to minimize their wholesale purchase costs.

- The Commission can stimulate greater demand response for the wholesale market by requiring the California ISO to allow scheduling coordinators to bid load responses in the ancillary services market (reserves, etc.). Scheduling coordinators could receive bids from those willing to provide a load reduction and then bid those in the ancillary services market. The scheduling coordinators could arrange with the ISO, on a bilateral basis, terms such as price and performance measures.

To provide some price regulation while generation resources remain scarce and until regulatory changes are made to provide more demand response:

- The Commission could return to traditional cost-of-service regulation for generators in California. There is the potential that this option could result in relatively high rates if the acquisition premiums of the non-utility owners are taken into account. Also, this alternative may be inconsistent with an objective to encourage investment in new generation.

- The Commission could adopt limited term price caps for spot market sales (day-ahead and hour-ahead) in both the PX and the Cal-ISO. The price caps would apply for a fixed 18-month period, the period in which generation is currently predicted to remain scarce, and would allow time to develop a regulatory structure to provide greater demand response. The cap would be set at a level that would permit recovery of current marginal costs, including opportunity costs, and be high enough to encourage new investment. An alternative would be to apply this limited-term price cap to all short-term wholesale sales in the West.

- Alternatively, the Commission could adopt a limited-term price cap to apply to long-term sales in addition to spot market sales. Since wholesale forward prices in California are also high, as a result of conditions last summer, the Commission could also adopt a temporary price cap to apply to long-term sales, to allow time for new generation to enter the market and for the regulatory structure to permit greater demand response. This option could have the effect of discouraging new investment, particularly if investors rely on forward prices to signal the need for new investment.

- As an alternative to a price cap on long-term prices, the Commission could adopt target prices for long-term contracts in the California market, based on pre-summer prices. These would apply for an 18-month period as described in the price cap options above. Wholesale sellers that substantially exceed the target prices would be subject to close scrutiny to determine whether they are exercising market power, with a potential loss of their market-based rate authority.

- The Commission can leave the spot market and long-term market prices unconstrained. With the evidence of scarcity in the region, higher prices produced by the market may be the right stimulus to needed new investment. This option would be more effective if coupled with actions to improve the overall functioning of the market, such as improving demand responsiveness and minimizing the reliance on spot market purchases. The option can be coupled with increased monitoring of market participants for evidence of market power abuse.

- The Commission can implement locational market power mitigation measures, independent of the options for price caps.

- The Commission could change the auction rules used by the PX and the Cal-ISO to pay sellers what they bid rather than the market-clearing price. This option can be adopted independent of other pricing options.

To create a more stable regulatory environment:

- The Commission can abolish the current stakeholder governing boards of the Cal-ISO and the PX and require independent, non-stakeholder boards. This would also eliminate the need for the EOB, which could be abolished also.

- The Commission can retain the sole authority to impose price caps in wholesale market transactions and not delegate that authority to the Cal-ISO or the PX.

- Require the Cal-ISO and PX market monitors to report directly to the FERC any evidence of market power abuse for evaluation and action by the Commission, without prior review by their boards.

Other options:

- To eliminate underscheduling in the Cal-ISO, the Commission can change the incentives for suppliers to sell in real-time and require stronger penalties for real-time purchases, combined with increased options for IOUs to have broader supply portfolios.

- The Commission could direct a further investigation of generators with abnormally high unplanned outage rates or bidders into the PX to examine whether individual market participants may have engaged in withholding or price manipulation. This option could be coupled with increased reporting to the Commission, as discussed in other options.

Discussion of Options

1. Encourage Investment in New Generation

Most projections for new generation capacity additions indicate that a significant amount of new capacity is planned to be available in 2002. Until new generation is added in the West, high prices can be expected to recur. While high prices are necessary to stimulate investment in new generation, barriers to the entry of new supplies into the market will result in a longer period of high prices than may be necessary. Federal, state and local regulatory policies should be designed to eliminate unnecessary barriers to new generation and to create incentives for new investment.

Specific rules about siting and local approval processes are within the control of state and local policymakers. Some steps have been taken in California to speed the local approval, but there may be more things that can be done.

At the federal level, Commission pricing policies can have an important impact on investment decisions. If wholesale prices are kept too low through regulatory controls, this can cause investors to invest in other markets. For example, if the Commission imposes wholesale price caps in California that are too low, generators may choose to build in Arizona or Nevada where there would be no price caps but where there is a growing demand for power. To provide an incentive for new generation to be located in California as well as other western states, the Commission may need to explicitly take into account the need to stimulate new investment through pricing policies.

Another factor that affects investment decisions is the stability of the regulatory process. To finance new generation plants, firms need to be able to convince their investors that the regulatory environment is stable enough to assure a return over the life of the project. This past summer's experience with the constantly changing Cal-ISO price caps created instability for the market and aroused investor concerns about investing resources in California. Therefore, stability in pricing policies can be a factor in encouraging investment in new generation.

2. Remedy the Over-Reliance on Spot Market Purchases

Spot markets are inherently volatile. In eastern bulk power markets with an ISO only 10 to 20 percent of the load is served by spot market purchases, but in California almost 100 percent of the load served by the IOUs is served by purchases in the spot market. Shifting purchases out of the spot market to longer term contractual arrangements would create greater price stability for wholesale buyers and end-users. In this market context, day-ahead and day-of purchases are spot market purchases. Forward contracts, for purchases longer than day-ahead and day-of, are longer term contracts.

Forward contracts for energy potentially can provide IOUs and other load serving entities with a highly effective hedge against high costs in energy spot markets, while providing both buyers and sellers with a greater level of price certainty. If generators are otherwise able to exercise market power in energy spot markets, such contracts can help to mitigate the market power of the generators that contract to sell their output at a fixed price. Thus, forward financial contracts offer the potential to reduce both the cost impact of price spikes on consumers' bills, and the incidence and magnitude of the price spikes that occur.

There are several options available to shift purchases to forward contracting:

Eliminate the requirement for the three California IOUs to buy and sell through the PX. During the summer of 2000 the IOUs had limited authority to enter into forward contracts. The block-forward contract available to them through the PX is insufficiently flexible to provide them the full benefits of forward contracting. Eliminating the restrictions on their ability to forward contract and to purchase supplies outside the PX would provide them with the ability to create portfolios of supply contracts to get more stable energy costs. While the CPUC recently expanded the authority of the IOUs to enter into bilateral, long-term contracts, this authority is still limited.

These restrictions could be eliminated directly by the Commission through actions it could take within its wholesale jurisdiction. When the Commission originally approved the restructuring proposals of the IOUs, it found that any concerns it might have about the requirement at that time were outweighed by other considerations.[1] The Commission could now find that such restrictions have become an impediment to the stability and proper functioning of the wholesale market and require a change in the eligibility provisions of the PX to insure that any wholesale buyers in the PX have the ability to buy their supply from other sources, or could otherwise establish a similar condition as a prerequisite to the IOUs transacting business in the wholesale market.

One of the original reasons for the mandatory buy/sell requirement was a concern for potential affiliate abuse in the buying and selling of energy. There are other ways to deal with this concern. For example, the IOUs could be required to use most-favored nations clauses for any transactions with affiliates to ensure that the price agreed to in an affiliate deal is no higher than the prices paid to non-affiliates.

Require the IOUs to hedge and forward contract. This is a variant of the option discussed above. The difference is that, rather than just eliminating an impediment to hedging and forward contracting, the option goes a step further to require the use of these tools. This could be done as a requirement to purchase a certain percentage of a supply portfolio through different instruments, and it could be implemented either by the CPUC or the Commission in the same way as the option above. It has the disadvantage of substituting the judgment of regulators for the judgment of business

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[1] Pacific Gas & Electric Co. et al., 77 FERC ¶61,265 at 62,088 (1996).

managers as to the best way to create a balanced supply portfolio. Providing business managers with financial incentives for managing their business in a way that minimizes costs is usually a more effective regulatory strategy.

Require all in-California thermal generation capacity to bid into the California forward markets. This option is the flip-side of the option above. It may increase the amount of capacity made available in the forward markets and it would allow generators to arrange sales in the forward markets at whatever prices they can negotiate. Thus, forward market sales would be market based, and generators would be free to pursue their most profitable opportunities.[2] However, as an incentive to get the maximum amount of thermal capacity available in the forward markets, thermal generators would be required to submit bids at the generator's marginal operating cost in the ISO's real time market for any unsold capacity.[3] Enforcing such a requirement would prevent generators from withholding capacity from the market, so prices in the real time market would not be inflated due to the exercise of market power. In addition, suppliers would have less ability to exercise market power in the forward markets, because buyers could avoid inflated forward market prices by buying in the real-time market.

A requirement to bid at marginal operating cost does not take into account a generator's opportunity cost, which may exceed its marginal operating cost when other markets are transacting at higher prices. But while thermal generators may have opportunities to sell in multiple markets in advance of real time, those opportunities fade as real time approaches. By the time the real-time market is operating, a thermal generator has no opportunity to sell elsewhere if its bid is rejected, so it has no opportunity costs.

This requirement is an option for most thermal generators, but not for hydro generators or for other generators with an absolute limit on the amount of energy that they can produce. That is because these latter generators may face opportunity costs in real time, because production in one hour may reduce the amount of production that can occur in subsequent hours. For example, hydro generators often have a limited supply of their energy source (water), so producing electricity in one hour reduces the amount of water available to generate electricity in a subsequent hour. Thus, by producing electricity in one hour, a hydro generator foregoes the opportunity to receive revenue in a subsequent hour. By contrast, most thermal generators do not face a limited supply of their energy sources, so

[2] Forward market sales in this context could also include purely financial hedges, such as "contracts for differences," where a buyer and seller agree in advance to a contractually-specified price (called a "strike price") for a specified quantity. Then, after the real time market closes, the buyer and seller agree to make additional payments to each other based on the difference between the real time spot price and the strike price.

[3] In addition, regulatory must run and must take generators would continue to be required to bid into the PX energy market at $0, as they are currently required to do.

producing electricity in one hour does not reduce the amount of electricity that can be produced in subsequent hours. However, certain thermal generators may face absolute limits on the amount of energy that they can produce or on the amount of time that they are permitted to generate, for example, due to environmental regulations. Since California has a significant amount of old thermal generators subject to emissions limitations, this may not be an attractive option.

Another criticism of requiring generators to bid previously uncommitted capacity into the real-time market is that it may encourage too much reliance on the real time market and too little scheduling in the forward markets, and thus may create operational and reliability problems for the ISO. If over-reliance on the real time market creates undue operational problems, the option could be modified to require generators to bid into the PX's day-of energy market (rather than the real time market) at marginal operating costs. This option would still give generators the opportunity to arrange sales in other forward markets at advantageous prices before the Day-of market closed, although it would reduce slightly the time available to do so.

There are several options for establishing when the bidding requirement could be triggered. One option is to impose the requirement on all generators at all times. This option might be chosen if market power arises frequently, or if it is difficult for the ISO to predict in advance when market power will arise. Alternatively, if the ISO can accurately forecast when and where market power is likely to arise, the bidding requirement could be imposed in more limited circumstances. For example, if market power arises only during high demand periods, the bidding requirement could be imposed only when the ISO forecasts load in an hour to exceed a specified level. Or, the bidding requirement could be imposed on generators in defined areas when transmission constraints arise that create locational market power.

By differentiating between generators within California and generators outside California, this option can have the effect of balkanizing the wholesale market and discouraging new investment in generation in California. Also, it may be difficult to administer and enforce.

3. Provide More Demand Response to Wholesale Prices

Encourage California to implement policies to increase retail demand responsiveness to price. There are retail market reforms that California can take that would greatly benefit the wholesale market by creating more demand responsiveness.

In well functioning competitive markets, both suppliers and consumers are able to see and respond to market prices. Indeed, this is what allows competitive markets to achieve the efficient outcomes for which they are well noted. However, in electricity markets, such as those in California, consumers often must make their consumption decisions without knowledge of the true market price of electricity. Currently, most California consumers (those served by PG&E and Southern California Edison) do not face wholesale electricity prices because of a retail rate freeze. The resulting lack of demand responsiveness to wholesale prices can, at times, lead to excessively high wholesale prices. When supply is scarce relative to demand, competitive prices will rise to a level that reflects the value that the marginal consumer places on additional consumption. This additional increment above marginal running cost is referred to as the "scarcity rent." However, market prices in electricity markets like those in California cannot be expected to settle at this level if consumers do not have the ability to see these prices and to make known to the market, through their purchasing decisions, the value that they place on marginal consumption. Indeed, in the absence of demand responsiveness, prices in California and in markets elsewhere frequently rise well above this competitive level at times when demand is high and capacity is scarce.

One way to allow retail consumers to respond to wholesale prices is for retail rates to reflect wholesale prices. However, to ensure that retail consumers can respond effectively to wholesale prices, they should have some advance notice of the change in retail rate policy, so that they can prepare for the new retail rate design. In the meantime, their traditional service providers should face incentives to procure electricity for their customers at least cost. California policymakers could also increase demand responsiveness to wholesale electricity prices by encouraging greater retail competition.

California should consider, in the long term, reevaluating the status of IOUs as providers of both distribution and energy services to their retail load. While California formally permits retail customers to choose among alternative suppliers, in practice few new retail energy service providers have entered the market thus far. Greater competition among energy service providers for the retail load of the IOUs would create a strong downward pressure on the cost of energy in California. Promoting greater retail competition likely would require a formal separation of the IOU distribution service functions from any continuing role as an energy service provider. In addition, consideration may have to be given to changing the CTC recovery mechanism and to imposing a provider-of-last-resort obligation on the IOU. Also, consideration should be given to providing large retail consumers of IOUs, the traditional retail service providers, with real-time price signals that would allow them to respond to the wholesale prices.

As long as California regulates retail service provided by IOUs, then the IOUs should be given strong incentives to minimize their wholesale costs. Regulations should be avoided that allow load serving entities to pass through the costs of energy and ancillary services directly to retail customers without giving those customers the ability to respond.

The Commission can stimulate more demand response for the wholesale market by requiring the Cal-ISO to allow scheduling coordinators to bid load responses in the ancillary services market. To implement this option, scheduling coordinators could receive bids from any user willing to provide a load reduction. The scheduling coordinators could arrange with the ISO, on a bilateral basis, the terms such as price and performance measures. This would not obviate the need of the CPUC to design demand response mechanisms for the retail market, but it is an option available to the Commission independent of the retail regulation.

4. Provide Some Price Regulation While Generation Resources Remain Scarce and until Regulatory Changes Are Made to Provide Greater Demand Response

The Commission could return to traditional cost-of-service regulation for generators in California. Traditional cost-of-service regulation is used when the market cannot be relied on to keep prices within a reasonable range because the regulated company exercises monopoly power. Under traditional cost-of-service ratemaking, a company is allowed to recover its prudently incurred fixed and variable costs plus its cost of capital including a reasonable return on its investment. Fixed and variable costs include operation and maintenance expenses (including fuel and emission allowances), depreciation, and taxes. The return on investment is calculated by multiplying the rate of return times the jurisdictional public utility's rate base. Rate base is calculated by subtracting from gross plant in service any accumulated reserve for depreciation associated with that plant and adding or subtracting from the net plant value any adjustments to rate base (such as accumulated deferred income taxes).

Prior to the divestiture of generating assets in California, jurisdictional utilities recorded these expenses consistent with the Commission's Uniform System of Accounts and annually filed a FERC Form 1 detailing their operating expenses including specific generating plant data in accordance with the Uniform System of Accounts. However, the new owners of the divested generating units are no longer required to follow the Commission's Uniform System of Accounts; nor are they required to file with the Commission a FERC Form 1. Therefore, the data needed to calculate a traditional cost-of-service rate is not currently collected and would have to be acquired. Determining a cost-based rate for every generation owner in California would involve numerous filings dealing with complex cost-of-service issues such as the appropriate depreciation rate for the unit, how income taxes would be calculated, capital structure, and the appropriate rate of return.[4] In addition, these cost-of-service issues may deal with issues of first impression because the new owners of each unit are, in many instances, limited liability corporations or partnerships. This is likely to be a complicated, time-consuming, administrative process.

The new generation owners purchased the divested generating assets of the IOUs for a premium over their net book value. In the past, the Commission has permitted the inclusion of acquisition adjustments in rate base for wholesale rates only if a utility can show that the investment decision is prudent and if it can demonstrate that the acquisition provides measurable benefits to ratepayers.[5] The Commission would need to address the prudence and benefits of these acquisition

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[4]The volume would increase substantially if cost-based rates were applied to generation owners outside of California (the entire WSCC) for their sales into the California market.

[5]*See* Minnesota Power & Light Company and Northern States Power Company, 43 FERC ¶ 61,104 at 61,342 (1988).

adjustments. If the Commission recognizes this premium in setting the new cost-based rates, the rates for these assets would be substantially higher than when the IOUs held the same assets prior to divestiture.

An alternative to including the full amount of the acquisition premium in the cost-of-service rates would be to exclude the acquisition premium from rates or offset the total acquisition premium by the amount that the generator made in the market (either this summer or since the transfer took place) over what it would have made under competitive circumstances. Either option would depress the value of the companies that purchased the generation assets and could present disincentives to future purchases of divested utility assets as part of retail access in other parts of the country.

Finally, if the Commission were to impose cost-of service rates for all wholesale sales in the California market, the Commission would also need to calculate cost-of-service rates for any remaining wholesale sales made by the three IOUs. The premiums received by the IOUs for their divested assets were used as an offset to their stranded costs. Any determination of a cost-of-service rate for the IOUs would need to take into account the total acquisition premium that was received by the IOUs to pay down the value of their stranded assets. The new cost-of-service rates for these assets should be lower than under the old regulated structure; however, whether the decrease in rates for these assets would offset the higher rates for the divested assets could only be determined after the Commission has had the opportunity to analyze all of the cost-of service rates for generation owners within California.

Traditional cost-of-service regulation is a reasonable option where the regulated firm exercises substantial market power, such as a natural monopoly, but is ill-suited to markets where firms have market power but also face some competition. Traditional cost-of-service regulation does not allow the firm the flexibility to respond to market signals, for example to lower prices, and still earn its allowed reasonable return because it cannot raise prices enough at other periods to compensate for the lower price periods. In those cases, other forms of price regulation are better suited. In the West, Commission regulated generators face competition from public power and power marketers, so traditional cost-of-service regulation may not be appropriate. In addition, traditional cost of service regulation is an administratively costly method of regulation because it is resource intensive, both for the regulatory agency and for the regulated firm. It can add significant transaction costs to an industry that may not be commensurate with the amount of protection it would provide in a particular context. Finally, a return to cost-of-service rates, even for an interim period, would create regulatory uncertainty that would likely exacerbate existing supply problems within California, and would have an adverse rippling effect in other electric markets in the country.

The Commission could adopt limited term price caps for spot market sales (day ahead and day of) in both the PX and the Cal-ISO. To give some protection from high prices until new generation plants are expected to come on line in 2002, and to provide time for the development of regulatory changes to stimulate greater demand response and thus better price signals for the wholesale market, the Commission could impose price caps on the spot market in California.

To provide certainty for the market the cap should be imposed for a limited, fixed duration and, if the level of the cap changes, the changes should occur in predictable ways.

In addition to certainty and predictability, there are some other factors to be taken into account in setting a price cap. Ideally a price cap should be high enough to attract generation investment to the market, but low enough to provide protection to consumers during the short-term. It should be high enough to permit the recovery of current marginal running costs and opportunity costs and provide a stimulant to new investment. Another consideration is that the price cap on the spot market should be high enough to provide an incentive for buyers to enter into long-term contracts. It also should apply equally to all sellers in the market so, for example, sales in the PX would be capped at the same price as sales to the Cal-ISO.

The existing ISO buyers' cap appears to be too low. The current cost data show that at the end of the summer it started to come very close to the variable costs (fuel and emissions) of a combustion turbine. As the costs of generating electricity have gone up the price cap has gone down, narrowing the band of prices traded. A price cap at this level is unlikely to be high enough to stimulate new investment.

The Commission could set the price cap at the cost of entry into the California market. One difficulty with this choice is choosing the type of capacity that would enter the market. The cost of entry could be the cost of transmission expansion that would increase the import capability into California or it could be tied to the cost of a new generating unit. Since transmission capacity did not appear to be a significant constraining factor contributing to high prices in the West this summer, the cost of a new generating unit may be a more logical choice. The cost of a new generating unit could vary greatly depending upon whether the unit entering the California market is baseload, intermediate or peaking capacity.

Alternatively, the Commission could set the price cap using a formula tied to the marginal cost of the highest cost unit in the WSCC. This would provide a transparent price, reflect the actual cost of generation that could reach the California market, and would still be high enough to attract new, lower cost capacity to California. Determining the actual cost of this benchmark unit may be difficult, however, because it would require obtaining short run marginal cost data for all units in the WSCC to discover the highest cost unit, and then trying to determine the opportunity costs of this unit.

The Commission could choose to bifurcate the market and impose a price cap when load exceeds a specified level. Data supplied from the ISO indicate that the market deviates from normal operating conditions when load exceeds 35,000 MW. The Commission could impose a price cap when load exceeds this level. All price caps, unless set very high, have the effect of removing incentives for wholesale buyers to hedge against peak prices because the cap protects against high prices. However, this particular price cap option appears to highlight that effect since the price cap would become binding only at the time when scarcity becomes a serious factor. This could have a dampening effect on the forward market and would not provide needed incentives for shifting purchases out of the spot market into the long-term market.

To provide certainty to the market, any price cap that the Commission chooses would need to be a hard cap that does not change during the transition period, or if it does change the changes should occur in predictable ways. The ISO changed its buyers' cap twice during the summer. These rapid changes in the ISO's buyers' cap created significant uncertainty for both power suppliers and buyers. This uncertainty increases the likelihood that suppliers will transact in more stable markets outside of California. In addition, it has been alleged that changes to the ISO's buyers' cap caused contractual problems for some participants in the California market that may have hedged at a price that was higher than that permitted under the most recent buyers' cap.

An alternative to a price cap for just the California market would be to apply the price cap to the entire WSCC.[6] Applying price caps just to California could balkanize the western wholesale market and cause power to be exported from California to other states without a cap, causing continued shortages and high prices in California. On the other hand, it may be unnecessary to apply price caps to the entire WSCC since prices at other hubs in the WSCC were highly correlated with California prices. Thus, prices throughout the WSCC could be expected to track capped prices in California, even if the cap is not extended to the entire WSCC. A potential problem with applying a WSCC-wide price cap is that approximately 50 percent of the installed generating capacity in the WSCC is nonjurisdictional and would not be subject to the cap. Governmental entities sell their excess power in the wholesale market and, as was seen this last summer, the amounts sold can be significant.[7] Thus the cap would be inapplicable to a large portion of the WSCC market and therefore could be ineffectual.

As previously noted, there are several potential levels for a price cap; however, whatever price cap is chosen, it should terminate at a predetermined time. Since the reasons for imposing a price cap would be to provide time for new generation to come on line and time for regulatory structures to be developed to provide a demand response, it would be reasonable to tie a price cap to a specified period needed for these changes. Significant new generation is currently planned to be on line in 2002, so an 18-month period would be reasonable. This should provide the time needed for California to site new generation as well as time to make necessary changes to its retail market structure to improve demand responsiveness. If California does not implement the reforms needed at the state level, the Commission should not extend the date. The market needs certainty and the high prices that result from scarcity should be felt by wholesale buyers and end-users so they can make rational choices about their

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[6] A WSCC price cap of this type would only apply to transactions that are comparable to the PX and ISO markets, i.e., on day-ahead and hour-ahead trades.

[7] "Power Points: Winners in $4 Billion Calif Sweepstakes," Dow Jones Energy Service (Sept. 29, 2000) (BPA, Salt River Project, LADWP and BC Hydro sold significant amounts of power.)

energy consumption. Californians are unlikely to be able to decide the relative values they place on environmental issues, public participation in governmental decision making, and electricity usage, or the value of obtaining supplies from the grid or from other sources, unless they know the cost of these choices.

Instead of a specified date, another option would be to terminate the price cap when the reserve level for the California market reaches a certain percentage. Under this option, a reasonable percentage could be established at a planning reserve number tied to the annual peak for the California market. Terminating the price cap when the specified reserve level is achieved should prompt generation expansion in California because the sooner generators increase their generation capacity the sooner the cap will be removed. This also provides certainty for investors that the rules are fixed and will not change. This may, however, diminish incentives for the state to expedite the siting of new generation.

Alternatively, the Commission could adopt a limited-term price cap to apply to long-term sales in addition to spot market sales. Since wholesale forward prices in California are high, as a result of conditions last summer, the Commission could also adopt a temporary price cap for long-term sales. The rationale for this cap would be the same as the spot market cap—to allow time for the entry of new generation and the development of regulatory mechanisms to provide a demand response. Even if the California IOUs are permitted, and/or encouraged, to develop balanced supply portfolios with more long-term supplies, buying long-term now may reduce the volatility of their supply costs, but it may not provide significant savings because current forward prices are high. Putting a cap on these forward prices would allow time for the market to recover from the summer prices that were unusually high because of a combination of factors. Choosing the correct level for this cap may be difficult. If investors rely on forward prices, more than spot prices, to signal the need for new investment, then finding the right long-term cap that will not discourage new investment may be a delicate task.

As an alternative to a price cap on long-term prices, the Commission could adopt target prices for long-term contracts in the California market, based on pre-summer prices. A less intrusive form of intervention would be to adopt some form of target price for forward contracts for an 18-month period. The target price, or prices, would be voluntary but any wholesale seller who sold too far above the target would be subject to investigation for the possibility of exercising market power. If the Commission determined that a seller was exercising market power, the Commission could rescind the market-based rates of the supplier.

One possible target price would based on the May 1, 2000, price for a standard six by sixteen futures contract for July 2000 delivery at California's path 15 (either NP15 or SP15). The May 1, 2000, target price would have to be adjusted for any increase in natural gas prices and emissions allowance credits since that date. May 1, 2000, might be a reasonable date upon which to base a forward target price because the markets at that time were operating under relatively normal conditions and prices for July 2000 delivery were consistent with prior periods, i.e., before market volatility appeared.

To implement this option the Commission may need to require monthly reporting of all individual forward contracts offered (both accepted and rejected) by suppliers to monitor their behavior during the transition period. The Commission could also encourage purchasers to report egregious offers by power suppliers.

This option could be combined with a requirement for generators to offer a particular amount of their supply in the forward market. However, there is no evidence that generators have been unwilling to commit to forward contracts and much anecdotal evidence that generators generally desire the financial stability provided by long-term contracts, at least for a portion of their supply. Therefore, this kind of requirement may be unnecessary, in addition to being intrusive in the market.

The option of a target price on long-term bilateral transactions, can be combined with a price cap on the spot market. Power suppliers with unsold generation from the bilateral market could have an incentive to drive up prices in the spot market during times of scarcity in order to maximize their revenue stream.

The Commission can leave the spot market and long-term market prices unconstrained. With the evidence of scarcity in the region, higher prices may be the correct market response to stimulate needed new investment. The high prices seen recently in the forward market may be the correct prices in light of the fact that shortages are likely to continue until 2002. Rather than trying to dampen those prices, it may be more beneficial to the market in the long run to leave those prices unconstrained. The experience in the Midwest after the price spikes in 1998 has been that significant generation resources were added to the region in response to those high prices. This option would be more effective if coupled with other actions to improve the overall functioning of the wholesale market, such as measures to provide a demand response and to minimize the reliance on spot market purchases. In addition, this option should be combined with increased monitoring of market participants to detect evidence of market power abuse, with any such conduct penalized if found.

The Commission can implement locational market power mitigation measures, independent of the other options for price caps. A single supplier may exercise locational market power because that supplier is the only option available to serve load in that area. The supplier may have several generating units at that location with more than enough supply available to meet demand; however, because of ownership concentration, the supplier can increase its price because of market power rather than scarcity of supply. The instances of market power may be isolated and infrequent, but this is an option available for mitigating the exercise of market power by a single supplier.

To mitigate the exercise of locational market power, the Commission could put in place resource specific bid caps. When a generator is called upon for a locational need, the unit would be paid either its bid cap if the market clearing price is lower, or the market clearing price if that price exceeds the bid cap. In no event would the generator set the market clearing price. The Commission could calculate the resource specific bid cap in several ways and let generator owners choose how they will be compensated. The resource bid cap could take several forms: (1) the Commission could require each generator to file the verifiable incremental operating cost which it would recover plus a margin for some recovery of fixed costs; (2) the resource bid cap could be equal to the market clearing price for similar hours and load levels when the unit's bid was in merit order with an adjustment for changes in fuel prices and emissions credits; or (3) the resource bid cap could be an estimate for running costs of a comparable unit. This option could be simplified to have one bid cap for each type of generating facility (e.g., stand-alone combustion turbines, combined cycle units, oil or natural gas-fired boilers).

This option is less intrusive than traditional cost-of-service regulation. It would be appropriate if there are significant barriers to new entrants and those barriers are unlikely to be removed. If new entry is possible, then an alternative would be to encourage other entrants into the market, and allowing the prices to be high is a way to attract new entrants.

The Commission could change the auction rules used by the PX and the Cal-ISO to pay sellers what they bid rather than the market-clearing price. Under this option the auction rules would be changed to pay each seller its bid, rather than the market-clearing price, and buyers would pay a price reflecting the average of the accepted sellers' bids. This might have the effect of lowering the total paid by buyers during high demand periods because some sellers would be paid less than the highest bid accepted. It may also change seller bidding behavior. Under this rule, sellers might submit higher bids than they might under a market-clearing price rule because under this rule the seller would only receive its bid, whereas under the market-clearing price rule, the seller would receive the market-clearing price even if the seller bid less. If generator bidding behavior changes in this way, it is not clear whether there would be much lowering of the total paid by buyers. Overall, it is not clear what effect this rule change might have on the total paid by particular consumers since consumers receive averaged monthly bills and not hourly bills.

5. Create a More Stable Regulatory Environment

The Commission can abolish the current stakeholder governing boards of the Cal-ISO and the PX and require independent boards, non- stakeholder boards. This would also eliminate the need for the EOB, which could be abolished also. The ISO and PX stakeholder board structures are designed to preclude dominance by one or two voting classes, but the stakeholder boards have difficulty coming to decisions on complex issues. These stakeholder governing boards are charged with making very difficult decisions that require satisfying a complex of regulatory authorities, often under conflicting political and stakeholder pressures, while maintaining a fiduciary responsibility to the ISO and PX. The stakeholder boards are more susceptible to influence by the interests that they represent or by the direct or indirect pressures of others and are becoming widely perceived as too easily influenced by local political pressure.

As the Commission recognized in Order 2000, independence is the linchpin which should form the basic foundation of an RTO and it should apply to all structures, including an ISO.[8] The Commission also reiterated that RTO governing boards have to satisfy the over-arching principle that their decisionmaking should be independent of market participants.[9] Recognizing that the Cal-ISO is required to make its RTO filing by January 15, 2001, this may be the time to require a restructuring of the ISO board from a stakeholder board to an independent board, with similar changes to the board structure of the PX. Changing the structure of these boards could increase regulatory certainty in the California market and bring some stability to the market. Eliminating the stakeholder boards would eliminate the need for the Electricity Oversight Board. This would remove an additional source of local pressure on these federally regulated entities and clarify the regulatory oversight of the wholesale market.

The Commission can retain the sole authority to impose price caps in wholesale market transactions and not delegate that authority to the Cal-ISO or the PX. The repeated changes in the Cal-ISO price caps this past summer appeared to be the result of a highly politicized decisionmaking process. This can be corrected by changing the board structure of the Cal-ISO, but to provide more stability to the market, any wholesale price constraints that need to be imposed should be imposed by the Commission. Only the Commission has the broad regional perspective necessary to evaluate fully the value and impact of price caps on the market.

Require the Cal-ISO and PX market monitors to report directly to the FERC any evidence of market power abuse for evaluation and action by the Commission, without prior review by their boards. The Cal-ISO and PX each have well established market monitoring units and independent surveillance committees that monitor market behavior. The Commission could require these entities to report any allegations and evidence of market power abuse directly to the Commission. While these entities have the discretion to file their reports directly with the Commission,[10] the current board structure may hinder the release of information that the Commission might find useful in its ongoing analysis of market behavior or that may be evidence of market power abuse that needs corrective action by the Commission.

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[8] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Statutes and Regulations ¶ 31,089 at 31,046-48 (2000).

[9] Id.

[10] Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,122, slip op at 248-49.

6. Other Options

To eliminate underscheduling in the Cal-ISO, the Commission can change the incentives for suppliers to sell in real-time and can require stronger penalties for real time purchases, combined with increased options for IOUs to have broader supply portfolios. The underscheduling that has been experienced by the Cal-ISO causes reliability problems for the ISO, so remedying this would appear to be important. It appears to be an outgrowth of pricing policies that provide incentives for both sellers and purchasers to underschedule and then buy in real time. To remedy this, the incentives need to be changed to give sellers an incentive to sell day ahead or in forward markets, and to give buyers both the ability to minimize their purchasing costs with the ability to forward contract and a disincentive to purchase in real time. For example, loads that purchase real time energy could be required to pay a premium above the currently-calculated prices and penalties for real time purchases. IOUs could also be allowed to purchase energy in forward markets outside the PX. On the supply side, one way to encourage generators to offer more energy in the forward markets would be to reduce the financial reward for providing replacement reserves. For example, any payments to a generator for providing replacement reserves could be considered as a down payment for any energy produced from the generator in real time. Thus, the price paid to the generator for such real time energy would be reduced by the amount paid for providing the replacement reserves.

The Commission could direct a further investigation of generators with abnormally high unplanned outage rates or bidders into the PX to examine whether individual market participants may have engaged in withholding or price manipulation. It may be appropriate for the Commission to take a more active role in investigating and dealing with individual instances of market power abuse. For example, one way to physically withhold capacity from the market is to contrive a forced outage. Of course, generation equipment will break down from time to time even in a competitive market; so unexpected, forced outages will naturally occur in any market. However, when a generator experiences an outage, capacity in the market is reduced, and that tends to raise the market price. So a generator might be able to exercise market power and raise the market price by contriving a forced outage, and thus, physically withholding capacity. It may be difficult to determine whether a forced outage is legitimate or contrived. However, when a generator's forced outage rate is abnormally high, especially during periods of tight capacity, it may be useful to investigate the outage in more detail to determine whether it has been contrived as an exercise of market power. If the outage is determined to be contrived, penalties could be imposed in order to deter similar future behavior.

In the time available for this investigation it was not possible to determine whether individual market participants abused their market power. An option available to the Commission is to direct staff to conduct a further investigation into individual conduct during the past summer.

With respect to future conduct, the Commission can revise its reporting requirements and market monitoring methods to provide a more systematic basis for monitoring for instances of market power abuse. Periodic market investigations, such as this investigation, are resource intensive efforts for the Commission staff as well as the Cal-ISO, PX and the market participants, that do not provide the kind of regular information collection needed to monitor the market and the behavior of individual participants on a regular basis. For example, the Commission could require generators to report unplanned outages to the Commission contemporaneously with the outage or soon thereafter. Although the Cal-ISO and the PX have market monitoring staffs, they do not have the same authority as the Commission to investigate individual behavior, and to take action against individual market participants.

Appendix A

Bulk Power Investigation: Entities Interviewed

Entity
California Independent System Operator
California Investor-Owned Utilities • Southern California Edison Company • San Diego Gas & Electric Company • Pacific Gas & Electric Company
California Power Exchange
California Public Utilities Commission
California and WSCC Generators and Marketers • Calpine Corporation • Constellation Power Source, Inc. • Duke Energy North America, LLC • Dynegy Power Corp. • Enron Power Marketing, Inc. • NRG Energy, Inc • PG&E National Energy Group • Reliant Energy Power Generation, Inc. • Southern Company Energy Marketing L.P. • Thermo Ecotek Corporation • Williams Energy Marketing & Trading Company
Electric Power Supply Association
Expert Economists • James Bushnell • William Hogan • Richard Tabors • Frank Wolak
National Rural Electric Cooperative Association
Northern California Power Agency
Office of the California Attorney General
Sacramento Municipal Utility District
The Utility Reform Network (TURN): Eric Woychik

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UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF CALIFORNIA

SAN FRANCISCO DIVISION

UNITED STATES OF AMERICA, Plaintiff, v. TIMOTHY N. BELDEN, Defendant.	No. CR 02-0313 MJJ PLEA AGREEMENT

I, TIMOTHY N. BELDEN, and the United States Department of Justice, by the United States Attorney's Office for the Northern District of California and the Enron Task Force (hereafter "the government") enter into this written plea agreement (the "Agreement") pursuant to Rule 11(e)(1)(B) of the Federal Rules of Criminal Procedure:

The Defendant's Promises

1. I agree to waive indictment and plead guilty to an information charging me with

conspiracy to commit wire fraud, in violation of 18 U.S.C. § 371. I agree that the elements of the offense and the maximum penalties are as follows: (1) there was an agreement between two or more persons to commit the crime of wire fraud in violation of 18 U.S.C. § 1343; (2) I became a member of the conspiracy knowing of at least one of its objects and intending to help accomplish it; and (3) one of the members of the conspiracy performed at least one overt act for the purpose of carrying out the conspiracy. The parties agree that the offense did not affect a financial institution within the meaning of 18 U.S.C. § 1343.

a.	Maximum prison sentence	5 years
b.	Maximum fine	$250,000
c.	Maximum supervised release term	3 years
d.	Mandatory special assessment	$100
e.	Restitution	Up to the amount of the loss

2. I agree that I am guilty of the offense to which I will plead guilty, and I agree that the following facts are true:

Between 1997 and 2002, I was employed by Enron Corporation. Specifically, I was the Director of Enron's California energy trading desk, and later Vice President and Managing Director in charge of Enron's West Power Trading Division (West Power) in Portland, Oregon. West Power marketed and supplied electricity to California wholesale customers through a number of energy and energy services markets run by the California Power Exchange (the California PX) and the California Independent System Operator (the California ISO). With limited exceptions, these entities were responsible for scheduling, managing, and arranging the payment for, all the electricity supplied to the State of California.

The markets run by the PX and ISO included the day-ahead, the day-of, the hour-ahead, and the real-time energy markets, into which energy marketers like Enron scheduled fixed amounts of electricity for delivery to wholesale and retail customers (known as retail "load"). Enron also sold stand-by electricity generation capacity, known as ancillary services, to the ISO, which was charged with ensuring that a fixed percentage of such capacity was available to prevent a collapse of the system in the event of an emergency. The ISO managed transmission capacity into, within, and out of the State, and paid fees to suppliers like Enron to alter electricity schedules in order to relieve "congestion" on particular transmission lines. The ISO also purchased energy from Enron and other suppliers "out-of-market" to address power emergencies, when the State had to address sudden increases in demand or inadequate scheduled supplies.

Beginning in approximately 1998, and ending in approximately 2001, I and other individuals at Enron agreed to devise and implement a series of fraudulent schemes through these markets. We designed the schemes to obtain increased revenue for Enron from wholesale electricity customers and other market participants in the State of California. The schemes required us to submit false information to the PX and ISO in the electricity and ancillary services markets described above. Among other things, we knowingly and intentionally filed energy schedules that misrepresented the nature of electricity we proposed to supply, as well as the load we intended to serve. We intentionally filed schedules designed to artificially increase congestion on California transmission lines. We were paid to "relieve" congestion when, in fact, we did not relieve it. We exported and then imported amounts of electricity generated within California in order to receive higher, out-of-state prices from the ISO when it purchased "out-of-market." We scheduled energy that we did not have, or did not intend to supply.

As a result of these false schedules, we were able to manipulate prices in certain markets, arbitrage price differences between the markets, obtain "congestion management" payments in excess of what we would have received with accurate schedules, and receive prices for electricity above price caps set by the ISO and the Federal Energy Regulatory Commission. We received the revenues from the above-described schemes through the ISO, which on a monthly basis billed all customers for wholesale electricity in California, and paid all suppliers, like Enron. I acknowledge that the ISO made these payments to Enron by interstate wire transmission through the Bank of America in San Francisco, California. For the purpose of carrying out the conspiracy, I and others involved in the schemes caused the ISO to transmit these payments to Enron monthly during the course of the conspiracy, from 1998 through 2001.

3. I agree to give up all rights that I would have if I chose to proceed to trial, including the rights to a jury trial with the assistance of an attorney; to confront and cross-

examine government witnesses; to remain silent or testify; to move to suppress evidence or raise any other Fourth or Fifth Amendment claims; to any further discovery from the government; and to pursue any affirmative defenses and present evidence.

4. I agree to give up my right to appeal my conviction, the judgment, and orders of the Court. I also agree to waive any right I may have to appeal my sentence, except that I reserve the right to appeal any upward departure.

5. I agree not to file any collateral attack on my conviction or sentence, including a petition under 28 U.S.C. § 2255, at any time in the future after I am sentenced, except for a claim that my constitutional right to the effective assistance of counsel was violated.

6. I agree not to ask the Court to withdraw my guilty plea at any time after it is entered.

7. I agree that the court may order and I will pay restitution in an amount to be determined based upon the amount of loss caused by my conduct, and I agree that the amount of restitution will not be limited to the loss attributable to the count to which I am pleading guilty, pursuant to 18 U.S.C. § 3663(a)(3). I agree that I will make a good faith effort to pay any fine, forfeiture or restitution I am ordered to pay. Before or after sentencing, I will, upon request of the Court, the government, or the U.S. Probation Office, provide accurate and complete financial information, submit sworn statements and give depositions under oath concerning my assets and my ability to pay, surrender assets I obtained as a result of my crimes, and release any of my funds and my property under my control in order to pay any fine, forfeiture, or restitution. I agree to pay the special assessment at the time of sentencing. I agree as part of my sentencing that the Court may enter an order prohibiting me from trading on, or trading subject to the rules of, any "registered entity," as that term is defined by the Commodities Exchange Act, 7 U.S.C. § 1a(29), during my term of supervised release.

8. I agree to waive all right, title, and interest I have in $2.1 million I received from Enron, which funds I acknowledge the government contends represents the proportional amount of compensation paid to me by Enron attributable to the scheme to defraud to which I am pleading guilty, and which is therefore criminally derived property, or traceable to and derived

from proceeds of criminally derived property, and thus subject to forfeiture. I stipulate that the $2.1 million is forfeitable on that basis. The $2.1 million received by me was placed in account nos 14703085 and 71096915 at Charles Schwab. I agree not to contest any civil forfeiture proceeding against those funds or bring any claim of interest to those funds in such action. I further agree to relinquish any and all right, title and interest I may have in these funds, and agree that such right, title and interest can be forfeited to the United States, without further notice to me. I also agree to execute and record any and all documents necessary to transfer the funds to the United States as part of a forfeiture judgment. In the event that I am subject to a monetary judgment arising from a successful claim by any third-party claimant in the Enron Corp. bankruptcy proceeding (In re: Enron Corp., et al., No. 01-16034 (AJG), S.D.N.Y.), the government agrees to dismiss its forfeiture action in the amount of any judgment. If no judgment is entered prior to the conclusion of the bankruptcy proceeding, the government shall be entitled to pursue a final judgment of forfeiture in the full amount of $2.1 million. The parties agree that the $2.1 million shall be applied against my obligation to pay restitution.

9. I agree to cooperate with the U.S. Attorney's Office before and after I am sentenced. My cooperation will include, but will not be limited to, the following:

a. I will respond truthfully and completely to any and all questions put to me, whether in interviews, before a grand jury or at any trial or other proceeding;

b. I will provide all documents and other material asked for by the government;

c. I will testify truthfully at any grand jury, court or other proceeding as requested by the government, including in any non-criminal federal proceeding or any state proceeding pursuant to paragraph 17, below;

d. I will surrender any and all assets acquired or obtained directly or indirectly as a result of my illegal conduct, as defined in paragraph 8;

e. I will request continuances of my sentencing date, as necessary, until my cooperation is completed;

f. I will tell the government about any contacts I may have personally with any co-defendants or subjects of investigation, or their attorneys or individuals employed by their attorneys.

10. I agree that the government's decision whether to file a motion pursuant to U.S.S.G. §5K1.1, as described in the government promises section below, is based on its sole

and exclusive decision of whether I have provided substantial assistance and that decision will be binding on me. I understand that the government's decision whether to file such a motion, or the extent of the departure recommended by any motion, will not depend on whether convictions are obtained in any case. I also understand that the Court will not be bound by any recommendation made by the government.

11. I agree not to commit or attempt to commit any crimes before sentence is imposed or before I surrender to serve my sentence; violate the terms of my pretrial release (if any); intentionally provide false information or testimony to the Court, the Probation Office, Pretrial Services, or the government; or fail to comply with any of the other promises I have made in this Agreement. I agree that, if I fail to comply with any promises I have made in this Agreement, then the government will be released from all of its promises, but I will not be released from my guilty plea.

12. If I am prosecuted after failing to comply with any promises I made in this Agreement, then (a) I agree that any statements I made to any law enforcement or other government agency or in Court, whether or not made pursuant to the cooperation provisions of this Agreement, may be used in any way; (b) I waive any and all claims under the United States Constitution, Rule 11(e)(6) of the Federal Rules of Criminal Procedure, Rule 410 of the Federal Rules of Evidence, or any other federal statute or rule, to suppress or restrict the use of my statements, or any leads derived from those statements; and (c) I waive any defense to any prosecution that it is barred by a statute of limitations, if the limitations period has run between the date of this Agreement and the date I am indicted.

13. I agree that this Agreement contains all of the promises and agreements between the government and me, and I will not claim otherwise in the future.

14. I agree that this Agreement binds the U.S. Department of Justice only, and does not bind any other federal, state, or local agency.

<u>The Government's Promises</u>

15. The government agrees to move to dismiss any open charges pending against the defendant in the captioned indictment at the time of sentencing.

16. The government agrees not to file or seek any additional charges against the defendant that could be filed as a result of the investigation that led to the pending indictment.

17. The government agrees not to use any statements made by the defendant pursuant to this Agreement against him, unless the defendant fails to comply with any promises in this agreement. The government may, however, provide the defendant's statements to or require the defendant to submit to an interview by any federal or state agency, or require him to provide testimony in any federal or state proceeding, so long as his statements may not be used against him. The government may also tell the Court and the U.S. Probation Department about the full extent of the defendant's criminal activities in connection with the calculation of the Sentencing Guidelines.

18. If, in its sole and exclusive judgment, the government decides that the defendant has cooperated fully and truthfully, provided substantial assistance to law enforcement authorities within the meaning of U.S.S.G. §5K1.1, and otherwise complied fully with this Agreement, it will file with the Court a motion under §5K1.1 and/or 18 U.S.C. §3553 that explains the nature and extent of the defendant's cooperation and recommends a downward departure.

19. Based on the information now known to it, the government will not oppose a downward adjustment of three levels for acceptance of responsibility under U.S.S.G. § 3E1.1.

<u>The Defendant's Affirmations</u>

20. I confirm that I have had adequate time to discuss this case, the evidence, and this Agreement with my attorney, and that she has provided me with all the legal advice that I requested.

21. I confirm that while I considered signing this Agreement and, at the time I signed it, I was not under the influence of any alcohol, drug, or medicine.

22. I confirm that my decision to enter a guilty plea is made knowing the charges that have been brought against me, any possible defenses, and the benefits and possible detriments of

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proceeding to trial. I also confirm that my decision to plead guilty is made voluntarily, and no one coerced or threatened me to enter into this agreement.

Dated: October 17, 2002

TIMOTHY N. BELDEN
Defendant

KEVIN V. RYAN
United States Attorney

Dated: October 16, 2002

PATRICK D. ROBBINS
MATTHEW J. JACOBS
Assistant United States Attorneys
LISA V. TENORIO-KUTZKEY
Special Assistant United States Attorney

Leslie R. Caldwell by PDR

LESLIE R. CALDWELL
Director, Enron Task Force

I have fully explained to my client all the rights that a criminal defendant has and all the terms of this Agreement. In my opinion, my client understands all the terms of this Agreement and all the rights he is giving up by pleading guilty, and, based on the information now known to me, his decision to plead guilty is knowing and voluntary.

Dated: 10/17/02

Cristina C. Arguedas

CRISTINA ARGUEDAS
Attorneys for Defendant

Committee on Governmental Affairs
EXHIBIT #A-55b

ORIGINAL FILED OCT -9 4:11:44 CLERK, U.S. DISTRICT COURT NORTHERN DISTRICT OF CALIFORNIA

KEVIN V. RYAN (CSBN 118321)
United States Attorney

LESLIE R. CALDWELL (NYSB 1950591)
Director, Enron Task Force

~~SEALED BY COURT ORDER~~

UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF CALIFORNIA

SAN FRANCISCO DIVISION

UNITED STATES OF AMERICA, Plaintiff, v. TIMOTHY N. BELDEN, Defendant.	CR 02 No.: 0313 VIOLATION: 18 U.S.C. § 371 – Conspiracy to Commit Wire Fraud VRW SAN FRANCISCO VENUE

INFORMATION

The United States Attorney charges:

1. At all relevant times, Enron Corp. ("Enron") was a publicly traded Oregon corporation with its headquarters in Houston, Texas. Through its subsidiaries, Enron was engaged in the purchase and sale of natural gas and electricity, construction and ownership of pipelines and power facilities, provision of telecommunications services, and trading in contracts to buy and sell various commodities. Before December 2, 2001, Enron was the seventh largest corporation in the United States.

2. From approximately 1997 to February 2002, the defendant TIMOTHY N. BELDEN was employed by Enron in its West Power Trading Division ("West Power") in Portland, Oregon. From 1997 to 1998, BELDEN was the Director of West Power's California energy desk and was responsible for buying and selling wholesale electricity in the State of

California. In 1999, BELDEN was promoted to Vice President, and later Managing Director, of West Power. BELDEN oversaw the marketing and supply of electricity and related services by Enron to consumers of wholesale electricity in the Western United States.

3. Prior to 1996, the California wholesale electricity industry was organized around three regulated utilities, Pacific Gas & Electric Co., Southern California Edison, and San Diego Gas & Electric. The utilities provided electricity to retail customers, managed system reliability and the electric transmission system, and owned and operated the electricity generating plants. During this time, the price of electricity was set by the California Public Utilities Commission.

4. In 1996, California enacted legislation to restructure the state's electricity market. The legislation was intended to reconfigure the market from one dominated by monopoly utilities to one subject to market forces. While the utilities remained responsible for serving the needs of their electricity customers, the legislation required them to sell most of their electricity generation plants to private companies. The legislation also created two new institutions, the California Power Exchange ("PX") and the California Independent System Operator ("ISO"). The PX was intended to be the primary marketplace for wholesale electricity in California. The ISO was charged with managing the state's electricity transmission grid, which included maintaining a balanced energy market, purchasing "ancillary services" (readily available emergency stand-by power), and managing transmission flow over the electric power lines.

5. Through the markets operated by the PX and ISO, generators and energy marketers (including Enron) bid for and scheduled fixed amounts of electricity for delivery to their wholesale and retail customers (known as "load"). From 1998 to 2001, the PX operated two electricity markets, the "day-ahead market," for energy delivery the following day, and the "day-of market," for energy delivery the same day. The ISO operated the "real-time" electricity market. Through the "real-time" market, the ISO bought and sold power to account for and correct any imbalances between supply and demand during each operating hour. At ten minute intervals, the ISO also set the "ex-post" price for "real-time" supplies of electricity. Suppliers to the ISO typically received the highest price paid during the relevant interval.

6. The ISO was also responsible for managing California's electricity transmission

system. The transmission system is a set of interconnecting power lines that carry electricity into, through, and out of California. These power lines vary in both distance covered and electricity capacity. In part to ensure that electricity supplies did not exceed transmission capacity, the ISO required the schedules submitted by energy marketers and generators to identify the amount and type of electricity to be sent, where the electricity was coming from, and where it was going.

7. Depending upon the total amount of electricity scheduled and the net direction of the electricity flow, a power line could become "congested." When congestion occurred, an ISO computer program calculated a "congestion management fee." The fee was essentially a toll for using an overcrowded power line. The proceeds of that toll were paid to two groups: (1) the owners of the congested line; and (2) the entities who "relieved" congestion by either reducing the amount of scheduled energy or scheduling energy in the opposite direction of the congestion.

8. As noted above, the ISO also operated a market for "ancillary services." Through this market, the ISO bought stand-by electricity generation capacity that it could draw upon in the event of a sudden loss of electricity supply. By regulation, the ISO was required to have an amount of generation capacity on stand-by equal to 7 percent of the total amount of scheduled demand for the State. If the ISO anticipated that it would not have enough stand-by capacity available, it was forced to declare an Emergency. The ISO rated Emergencies as Stage 1, Stage 2, or Stage 3. A Stage 3 Emergency was the most severe Stage and indicated that, without significant ISO intervention, the supply of electricity to the ISO's control area (the vast majority of the State of California) was in danger of imminent collapse. Depending on the extent of the Emergency, the ISO ordered certain industrial customers to curtail their consumption of electricity, or ordered regional power blackouts.

9. When there was an insufficient amount of supply to meet demand, the ISO was forced to solicit additional electricity from outside California, known as "out of market" electricity. The purchase of "out of market" electricity was unlike any other electricity purchase, in that it was not subject to the federally-approved price cap for energy within the State of California.

10. On a monthly basis, the ISO calculated the total amount of electricity and ancillary services supplied by each energy marketer and generator, the associated congestion management fees, and the total amount of electricity consumed by each wholesale customer. The ISO then issued a net payment to the suppliers and billed the customers for the appropriate amounts due. The ISO sent payments to generators and electricity marketers (including Enron) for electricity, ancillary services, and congestion fees by wire transmission through the Bank of America in San Francisco, California.

11. The newly deregulated electricity market performed fairly well during its first two years of operation. However, on May 22, 2000, the California energy market fell into a crisis that continued for more than a year. Electricity supply declined. Generators often failed to operate their plants at full capacity and shut down plants at rates well-above historical averages. Due to this shortage of energy supply, the ISO repeatedly purchased "out of market" electricity at prices above the price cap. By late 2000, the rate of and price paid for "out of market" electricity rapidly accelerated. The price paid for "ancillary services" also jumped during the crisis. From November 2000 to December 2000, prices for all "ancillary services" increased between 127% and 650%. Finally, the prices for wholesale electricity in the PX and ISO markets also skyrocketed. Prior to May 2000, electricity prices consistently averaged $24 to $40 per megawatt hour (a megawatt hour is an amount of electricity sufficient to serve the needs of approximately 750 homes for a one-hour period). By December 2000, the height of the crisis, prices reached $1,500 per megawatt hour.

12. The California energy crisis impacted more than the price of electricity. The crisis threatened the reliability of California's entire electric system. From 1998 to 1999, the ISO declared 17 Emergencies, none of which were rated as a Stage 3. From 2000 to 2001, the ISO declared 265 Emergencies, 39 of which were Stage 3 Emergencies. Between November 1, 2000 and May 31, 2001, the ISO ordered power blackouts and service interruptions on 38 days. These blackouts and service interruptions disrupted commerce and compromised public safety, affecting roughly one-third of all Californians.

13. The ISO estimates that during the one year period between May 2000 and May

2001, purchasers of electricity in the State of California paid approximately $8.9 billion more than they would have under competitive market conditions. In 1999, Enron's electricity trading arm, West Power, generated approximately $50 million in revenues. In 2000, West Power generated approximately $500 million in revenue. In 2001, West Power generated approximately $800 million in revenue. This increase in Enron's revenue was attributable to the dramatic rise in electricity prices during the California energy crisis in 2000 and 2001 and to the execution of the schemes described below .

SCHEME TO DEFRAUD

14. Beginning in 1998 and continuing through 2001, within the Northern District of California and elsewhere, the defendant TIMOTHY N. BELDEN and others did knowingly devise and attempt to devise a scheme and artifice to defraud and to obtain money and property by means of false and fraudulent pretenses, representations, and promises from electricity customers in California and other participants in the California wholesale electricity markets.

15. It was part of the scheme and artifice that defendant BELDEN and other Enron officers and employees, directly and indirectly, engaged in trading strategies that involved the submission of false and fraudulent schedules, bids, and information to the PX and the ISO. Among other things, defendant BELDEN and others did knowingly file, and cause to filed, energy schedules and bids that:

(a) misrepresented the nature and amount of electricity Enron proposed to supply, as well as the load it intended to serve;

(b) created false congestion and falsely "relieved" congestion on California transmission lines, and otherwise manipulated the ISO's calculation of congestion management fees;

(c) misrepresented that energy was from out-of-state, when in fact the energy was from the State of California, exported and then imported back; and

(d) falsely represented that Enron intended to supply energy and ancillary services it did not in fact have, and did not intend to supply.

16. The purpose of the scheme and artifice to defraud was to artificially increase the

price Enron received, to receive payments for services Enron did not in fact provide, and to manipulate the market price in certain markets.

COUNT ONE: 18 U.S.C. § 371 (Conspiracy to Commit Wire Fraud)

17. Paragraphs 1 through 16 of this Information are realleged and incorporated as if fully set forth here.

18. In or about and between 1998 and 2001, both dates being both approximate and inclusive, within the Northern District of California and elsewhere, the defendant

TIMOTHY N. BELDEN

and others known and unknown, conspired to and did devise a scheme and artifice to defraud and to obtain money by false and fraudulent pretenses, representations, and promises, and for the purpose of executing such scheme and artifice, transmitted and caused to be transmitted wire communications in interstate commerce, all in violation of Title 18, United States Code, Section 1343.

19. Among the means and methods by which the defendant TIMOTHY N. BELDEN and his co-conspirators would and did carry out the conspiracy were those described in Paragraph 15 of this Information, as well as others.

20. In furtherance of the conspiracy and to effect the objects thereof, the defendant TIMOTHY N. BELDEN and his co-conspirators committed and caused to be committed the following overt acts in the Northern District of California and elsewhere: the monthly transmission by the ISO of payments to Enron for electricity, congestion fees, and ancillary services, sent by wire transmission through the Bank of America in San Francisco, California.

All in violation of Title 18, United States Code, Section 371.

DATED: 10/7/02

KEVIN V. RYAN
United States Attorney

CHARLES B. BURCH
Chief, Criminal Division

(Approved as to form:)
AUSAs: Robbins, Jacobs, Tenorio-Kutzkey

SOUTHERN CALIFORNIA
EDISON

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Committee on Governmental Affairs
EXHIBIT #A-56

Status of California Electricity Markets

August 3, 2000

Why California is different from NE/NY/PJM

- Flawed market structure
  - » FERC observed flawed congestion
  - » Flawed CA ISO real-time energy market
- Cost of Ancillary Services
  - » Observe costs for June
- Cost of energy - significant portion (90%) of load in spot markets
  - » Extent of divestiture and amount of load at market
  - » Impact of price spike for Diversified/Exposed portfolio
- Insufficient supply for competitive markets
  - » ISO forecast/concerns
- Impact on customer bills
  - » Recent SDG&E rates
  - » Impact on SCE rates
  - » California compared to US

California Markets are not Workably Competitive

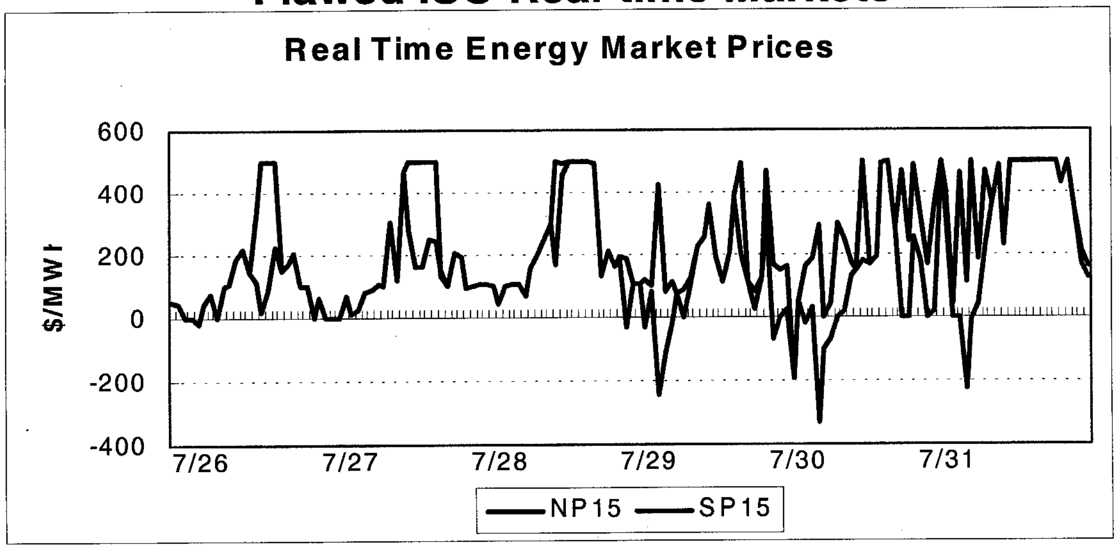
Experts, observers and participants acknowledge market problems

- FERC has concluded significant parts of the ISO market are "fundamentally flawed"
  - » FERC has ordered the ISO to redesign Congestion management (the method of allocating and pricing transmission and electricity)
- On 6/28/00 the ISO governing board passed a resolution16-4 to lower caps from $750/MWh to $500/MWh "In response to market performance indicating that during high load conditions the California .... markets are not workably competitive..."
  - » Board fell one vote short of lowering the cap to $250/MWh
- California state Senator Peace, Senator Bowen (Chair of the Senate Energy, Utilities, and Communication Committee) and Assemblymember Wright (Chair of the Assembly Utilities and Commerce Committee) concluded California markets are not workably competitive in recent letters to the ISO board
- Monitoring groups established by FERC (the ISO's Department of Market Analysis and Market Surveillance Committee, and the PX's Market Monitoring Committee) have reported on market flaws, the exercise of seller market power, and lack of workable competition

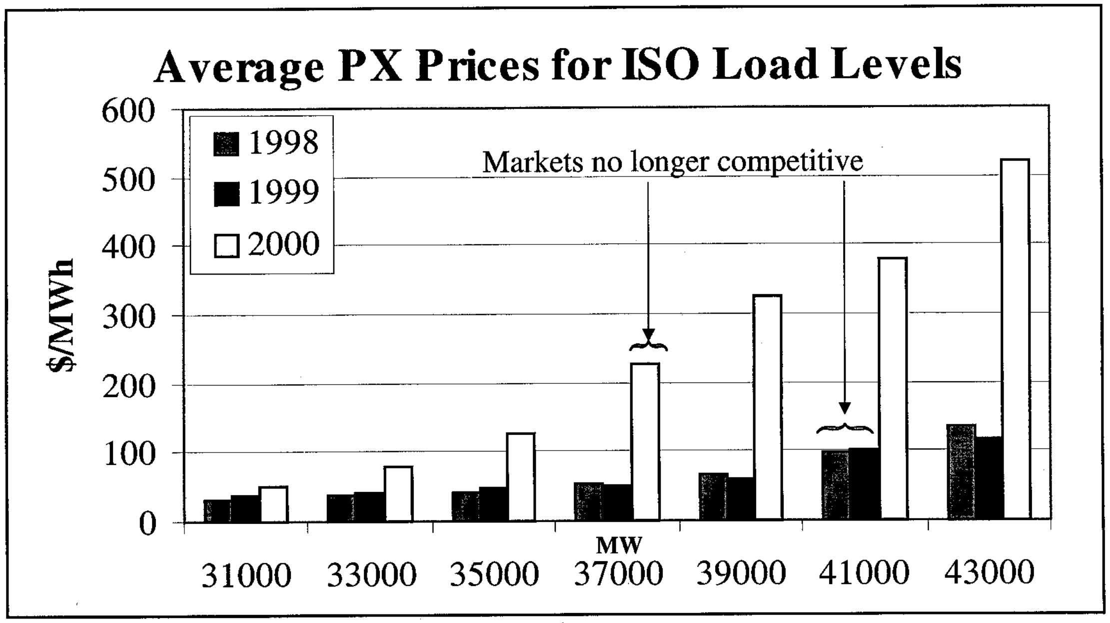
Costs of Existing Flawed Markets

- Under a $750/MWh cap, California energy costs exceeded **$3.6 billion** this June
  - » Total energy cost for all of 1999 was about $7 billion
  - » July 2000, with $500 cap, was about $2.4 billion
- During 10 days in June the ISO spent about $387MM on reliability services
  - » This *exceeded* the total cost for reliability services in all of 1999 of $384MM
- Dramatic increase in residential and commercial utility bills in areas without a rate freeze
  - » Recent San Diego bills were 13.5 cents/kWh for electricity
  - » The same electricity component in June 1999 was 2.8 cents/kWh
  - » When transmission, distribution and other standard charges are added, the current rates total over 20 cents/kWh, likely the highest in the nation
- Increased bills have resulted in customer outrage and a well publicized outcry
  - » Many are questioning the promised benefits of deregulation

Flawed ISO Real-time Markets

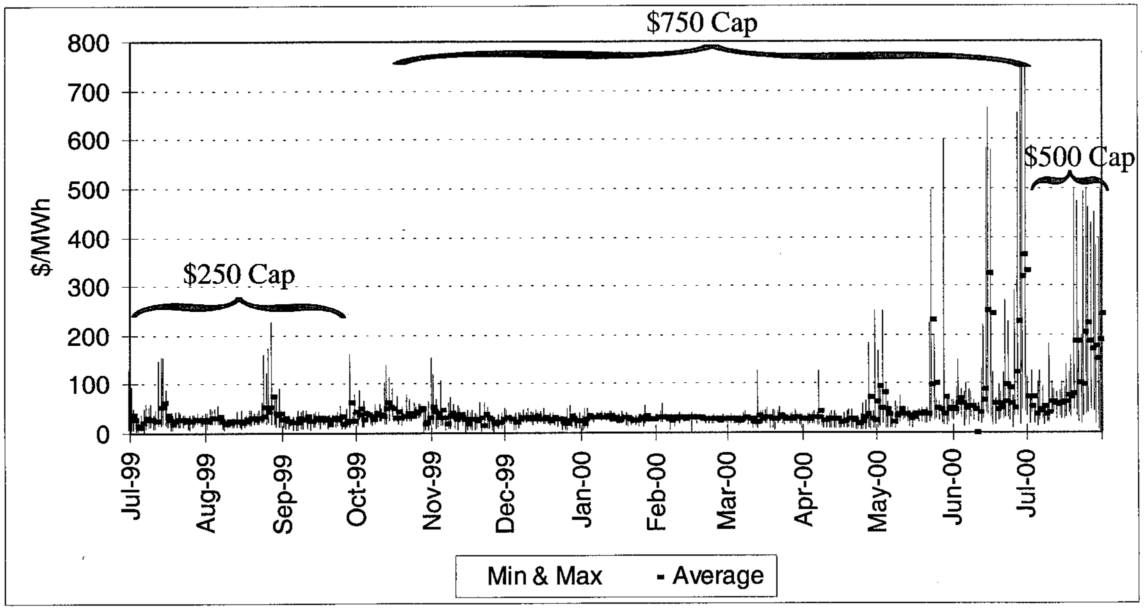


- Price magnitude, volatility and locational prices are inconsistent with a functional market



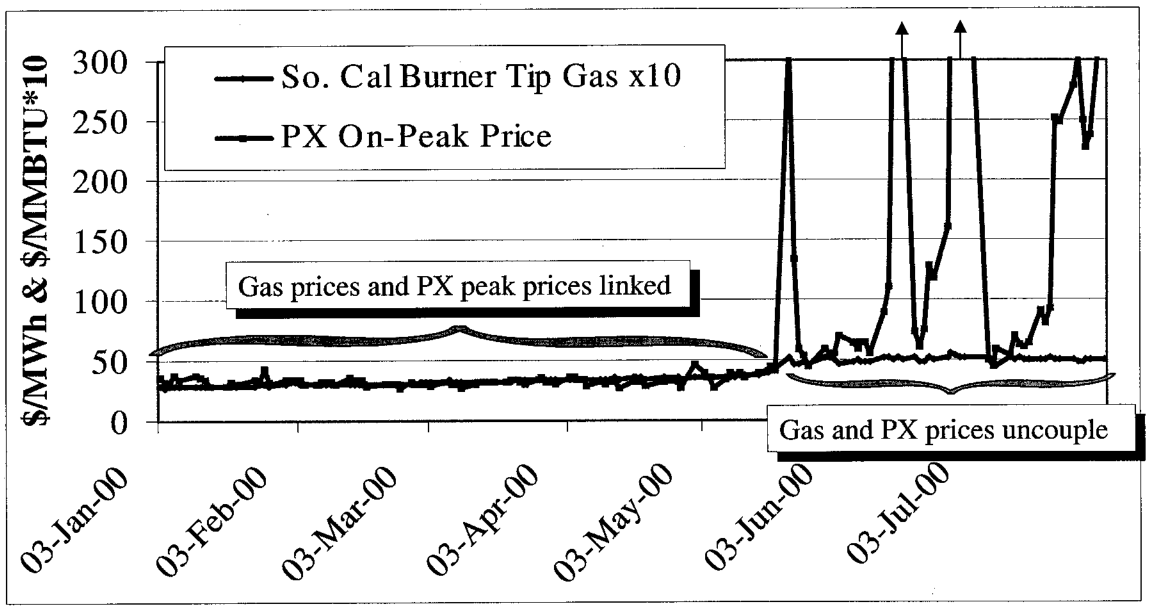
- Market became non-competitive at different load levels
  - » 1998 - 1999: non-competitive for loads above ≈ 40,000 MW
  - » 2000: non-competitive for loads above ≈ 37,000 MW
- Today, to competitively serve a peak load of 45,000MW, CA would require and additional 8,000MW of capacity bid at competitive levels

PX Day-Ahead Electricity Prices



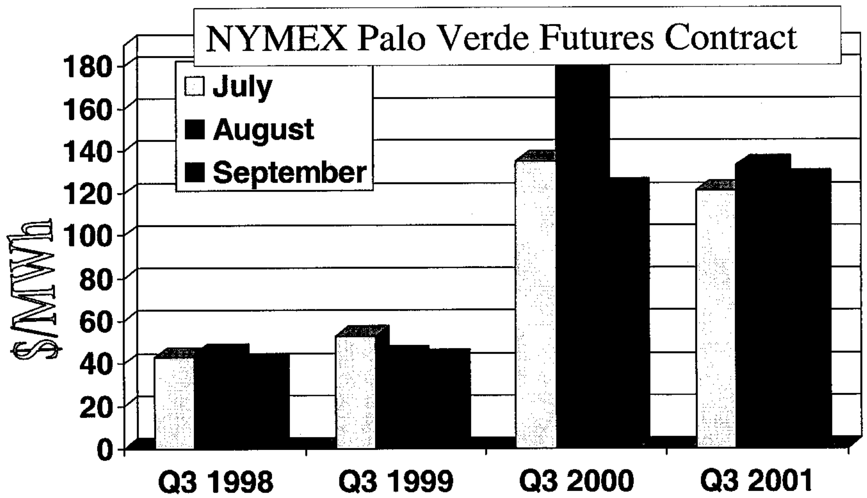
- PX SP15 zonal prices
  - » SCE and SDG&E purchase day-ahead electricity at the SP15 price

So Cal Burner Tip Gas and PX Peak Prices



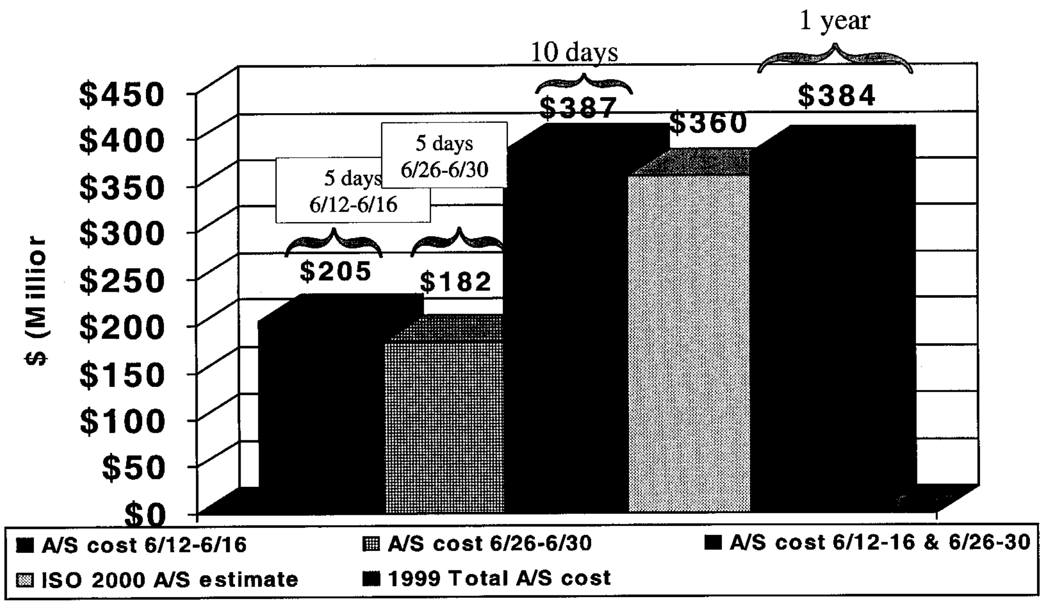
- Gas prices and PX peak prices remain linked until late May
- During summer loads, gas and electricity prices uncouple

Costs of Existing Flawed Markets



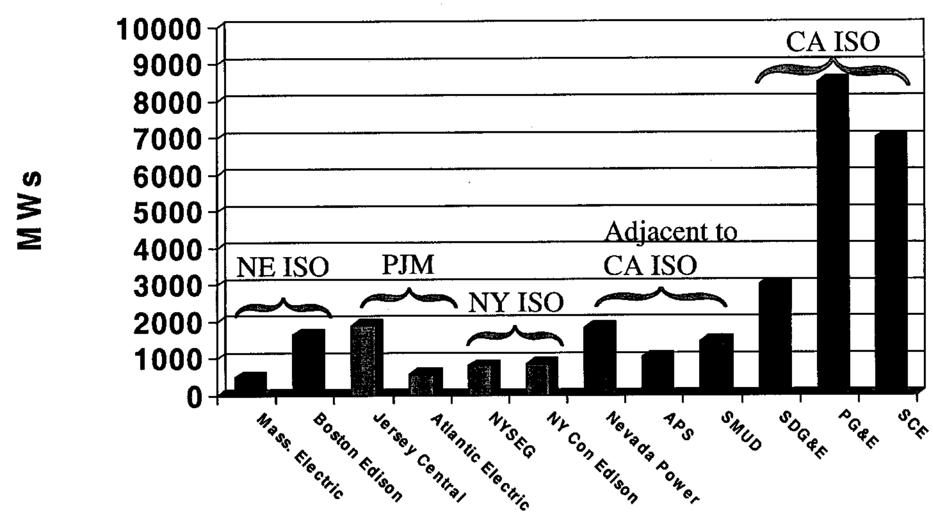
- Forward prices (the cost of insurance) have more than **doubled** since 1999
- These prices are $/MWh for monthly blocks of On-peak power (6am - 10pm, Monday through Saturday, excluding holidays)
- Every one dollar increase in forward price, the cost to purchase 100 MW increases by $125K

Costs of Flawed CA ISO Markets: Ancillary Services



- Ten day cost for reliability services: **$387 Million**
- This costs exceeds the total 1999 annual costs of $384 Million

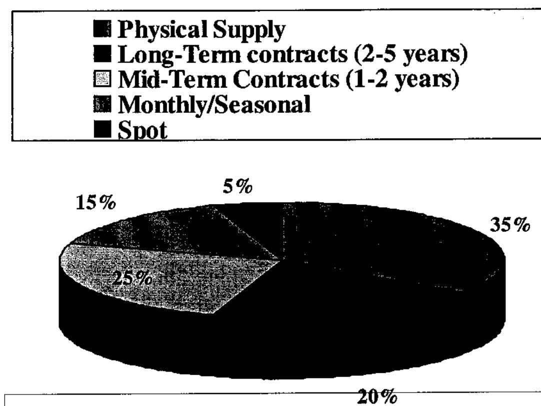
California Generation Divestiture



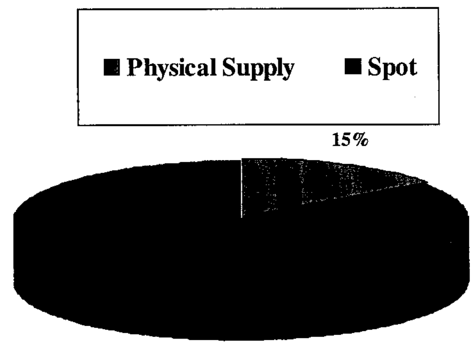
- Utilities in California purchase about 20,000MWs per hour from the market during hot conditions; high prices X large load = formidable costs
- In other regions, most utilities have excess generation and/or contracts and often *sell* into the market when prices are high.
- Source: Estimates based on FERC 1998 Form 861 and Form 1 adjusted to reflect impact of generation divestiture.

Energy Portfolios: Impact of Price Spikes

East-Coast Energy Portfolio

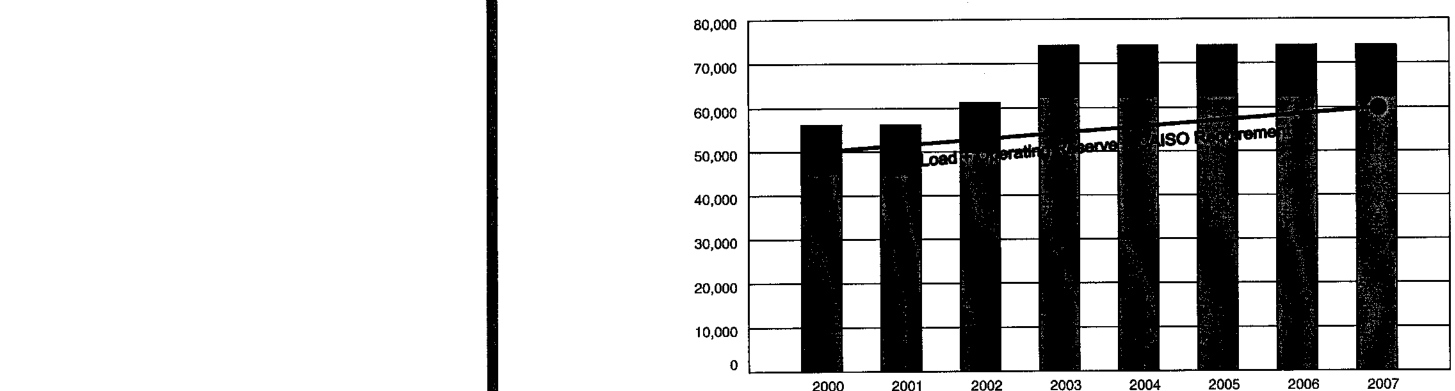


California Energy Portfolio



- Example:
  - » East-coast energy portfolio has 95% at $50 and 5% at spot
  - » California energy portfolio has 35% physical generation at $50 and 65% at spot
- Consider a price spike of $1000
  - » Customers with East-coast portfolio pays 95%*$50+5%*$1000 = **$97.50**
  - » Customers with California portfolio pays 15%*$50+85%*$1000 = **$857.50**

California ISO Load/Resource Forecast



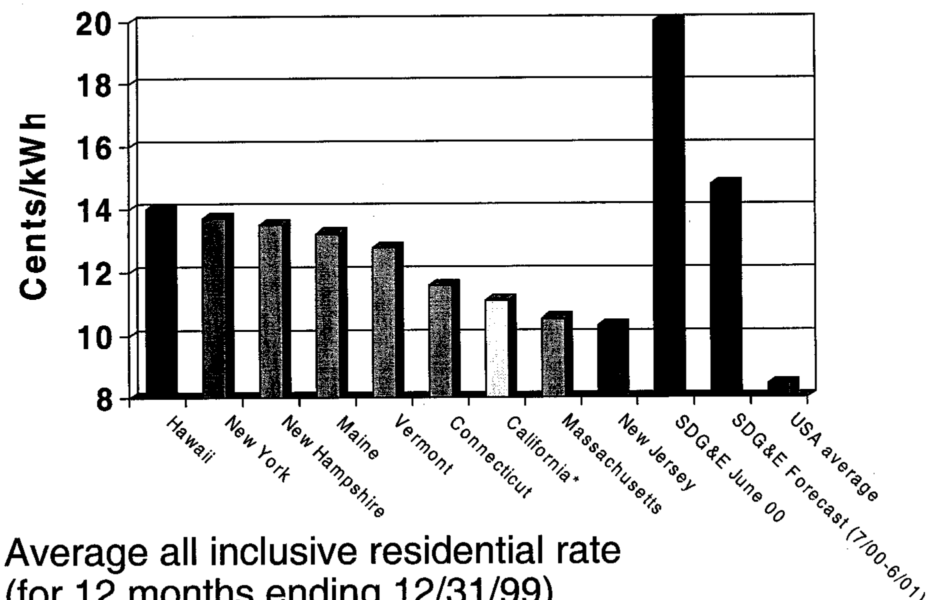
	2000	2001	2002	2003	2004	2005	2006	2007
Max Import Capacity	11,260	11,260	11,260	11,260	11,260	11,260	11,260	11,260
Max Avail. Gen. Capacity	45,565	45,602	50,011	62,861	62,878	62,861	63,190	63,180
Load Forecast + OR	***49,209***	***50,188***	***51,463***	***53,602***	***54,462***	***55,306***	***56,177***	***57,928***

Source: California Independent Operator

- Between May 22 - August 4, 2000, the ISO has declared:

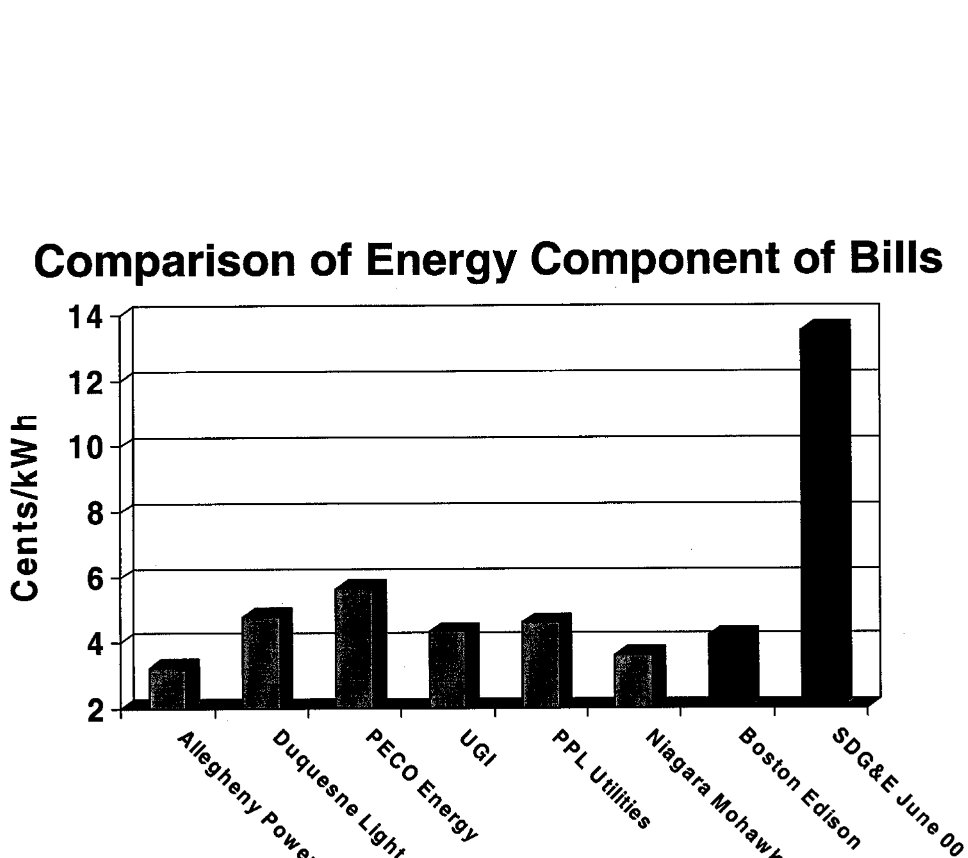
  16 Alerts, 17 Warnings, 16 Stage 1 Emergencies, and 10 Stage 2 Emergencies
- Supply/demand conditions will likely not improve for several years

Residential Rates of Most Expensive States



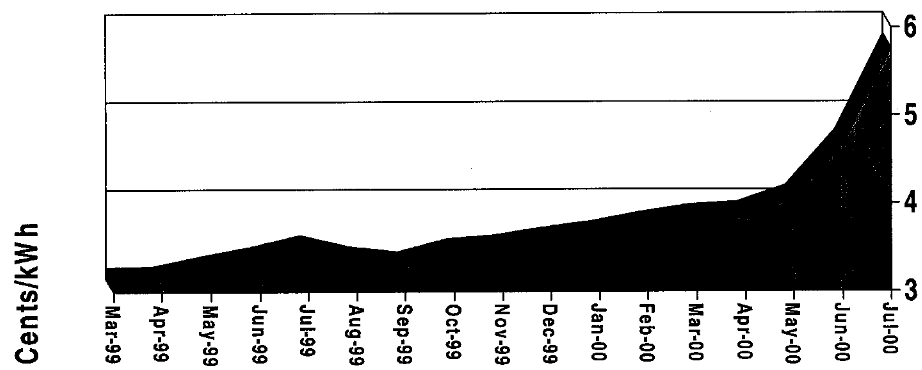
- Average all inclusive residential rate (for 12 months ending 12/31/99)
- * PG&E and SCE only
- Source: Edison electric institute; SDG&E data source: Presentation from Energy Summit, July 12, 2000

Comparison of Energy Component of Bills



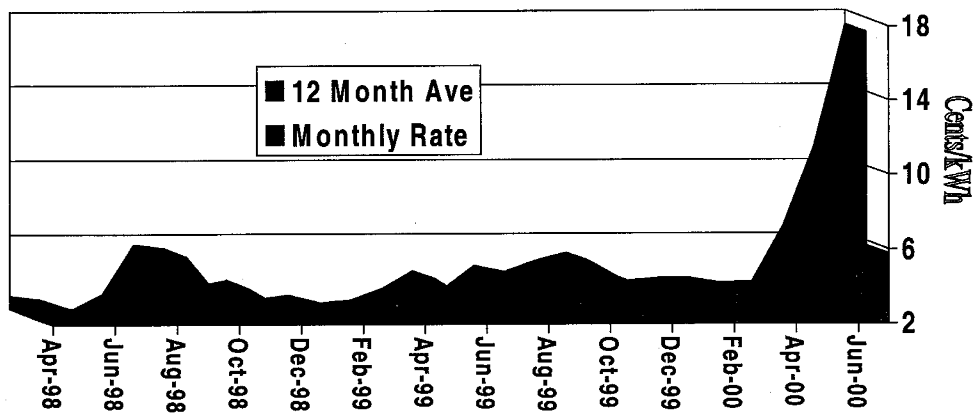
- Values represent energy "shopping credits" for residential customers in Pennsylvania, New York and New England
- Actual SDG&E charge is for June 2000
- Source: Edison electric institute

12 Month Rolling Average SCE Residential Energy Component



- Twelve month rolling average for July 2000 is 5.8 cents/kWh
- Twelve month rolling average for July 1999 was 3.5 cents/kWh
  - » This represents a 65% increase in annual average rates
  - » As high summer prices continue this average rate will likely increase

Monthly and 12 Month Rolling Average SCE Residential Energy Component



	Mar-99	Apr-99	May-99	Jun-99	Jul-99	Aug-99	Sep-99	Oct-99	Nov-99	Dec-99	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00
Monthly	2.4	3.0	4.0	3.0	4.3	3.9	4.6	5.0	4.0	3.5	3.6	3.6	3.3	3.4	6.4	10.7	17.3
12 Month Rolling Average	3.1	3.1	3.3	3.3	3.5	3.3	3.3	3.4	3.5	3.6	3.6	3.7	3.8	3.8	4.0	4.7	5.8

- All prices are Cents/kWh
- 12 month rolling average not available prior to March 99

What Needs to be Done

- California needs more supply
- Price too high even given tight supply
  - » Weekend load is 40% lower but prices still supracompeitive
  - » Non-peak hours supracompetitive
  - » No resources have costs at these levels
- Improve transparency in bilateral markets
  - » Parties can acquire market power via contract without detection
- More effective rules to mitigate market power

Committee on Governmental Affairs
EXHIBIT #A-57

Reviewed for Privilege
1435
Rev'r OM Bx 4/24/03

STOEL RIVES LLP

MEMORANDUM

December 6, 2000

TO: RICHARD SANDERS

FROM: CHRISTIAN YODER AND STEPHEN HALL

RE: Traders' Strategies in the California Wholesale Power Markets/ ISO Sanctions

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CONFIDENTIAL: ATTORNEY/CLIENT PRIVILEGE/ATTORNEY WORK PRODUCT

This memorandum analyzes certain trading strategies that Enron's traders are using in the California wholesale energy markets. Section A explains two popular strategies used by the traders, "inc-ing" load and relieving congestion. Section B describes and analyzes other strategies used by Enron's traders, some of which are variations on "inc-ing" load or relieving congestion. Section C discusses the sanction provisions of the California Independent System Operator ("ISO") tariff.

A. The Big Picture

1. "Inc-ing" Load Into The Real Time Market

One of the most fundamental strategies used by the traders is referred to as "'inc-ing' load into the real time market." According to one trader, this is the 'oldest trick in the book' and, according to several of the traders, it is now being used by other market participants.

To understand this strategy, it is important to understand a little about the ISO's real-time market.[1] One responsibility of the ISO is to balance generation (supply) and loads (demand) on the California transmission system. During its real-time energy balancing function the ISO pays/charges market participants for increasing/decreasing their generation. The ISO pays/charges market participants under two schemes: "instructed deviations" and "uninstructed deviations." Instructed deviations occur when the ISO selects supplemental energy bids from generators offering to supply energy to the market in real time in response to ISO instructions. Market participants that increase their generation in response to instructions ("instructed deviation") from the ISO are paid the "inc" price. Market participants that increase their

[1] The "real-time" energy market is also known as the imbalance energy market. The imbalance energy market can be further subdivided into the (1) supplemental energy or instructed deviation market and (2) the ex post market or uninstructed deviation market.

generation without an instruction from the ISO (an "uninstructed deviation") are paid the ex post "dec" price. In real-time, the ISO issues instructions and publishes ex post prices at ten-minute intervals.

"'Inc-ing load' into the real-time market" is a strategy that enables Enron to send excess generation to the imbalance energy market as an uninstructed deviation. To participate in the imbalance energy market it is necessary to have at least 1 MW of load. The reason for this is that a generator cannot schedule energy onto the grid without having a corresponding load. The ISO requires scheduling coordinators to submit balanced schedules; i.e., generation must equal load. So, if load must equal generation, how can Enron end up with excess generation in the real-time market?

The answer is to artificially increase ("inc") the load on the schedule submitted to the ISO. Then, in real-time, Enron sends the generation it scheduled, but does not take as much load as scheduled. The ISO's meters record that Enron did not draw as much load, leaving it with an excess amount of generation. The ISO gives Enron credit for the excess generation and pays Enron the dec price multiplied by the number of excess megawatts. An example will demonstrate this. Enron will submit a day-ahead schedule showing 1000 MW of generation scheduled for delivery to Enron Energy Services ("EES"). The ISO receives the schedule, which says "1000 MW of generation" and "1000 MW of load." The ISO sees that the schedule balances and, assuming there is no congestion, schedules transmission for this transaction. In real-time, Enron sends 1000 MW of generation, but Enron Energy Services only draws 500 MW. The ISO's meters show that Enron made a net contribution to the grid of 500 MW, and so the ISO pays Enron 500 times the dec price.

The traders are able to anticipate when the dec price will be favorable by comparing the ISO's forecasts with their own. When the traders believe that the ISO's forecast underestimates the expected load, they will inc load into the real time market because they know that the market will be short, causing a favorable movement in real-time ex post prices. Of course, the much-criticized strategy of California's investor-owned utilities ("IOUs") of underscheduling load in the day-ahead market has contributed to the real-time market being short. The traders have learned to build such underscheduling into their models, as well.

Two other points bear mentioning. Although Enron may have been the first to use this strategy, others have picked up on it, too. I am told this can be shown by looking at the ISO's real-time metering, which shows that an excess amount of generation, over and above Enron's contribution, is making it to the imbalance market as an uninstructed deviation. Second, Enron has performed this service for certain other customers for which it acts as scheduling coordinator. The customers using this service are companies such as Powerex and Puget Sound Energy ("PSE"), that have generation to sell, but no native California load. Because Enron has native California load through EES, it is able to submit a schedule incorporating the generation of a generator like Powerex or PSE and balance the schedule with "dummied-up" load from EES.

Interestingly, this strategy appears to benefit the reliability of the ISO's grid. It is well known the California IOUs have systematically underscheduled their load in the PX's Day-

Ahead market. By underscheduling their load into the Day-Ahead market, the IOUs have caused the ISO to have to call on energy in real time in order to keep the transmission system in balance. In other words, the transmission grid is short energy. By deliberately overscheduling load, Enron has been offsetting the ISO's real time energy deficit by supplying extra energy that the ISO needs. Also, it should be noted that in the ex post market Enron is a "price taker," meaning that they are not submitting bids or offers, but are just being paid the value of the energy that the ISO needs. If the ISO did not need the energy, the dec price would quickly drop to $0. So, the fact that Enron was getting paid for this energy shows that the ISO needed the energy to balance the transmission system and offset the IOU's underscheduling (if those parties own Firm Transmission Rights ("FTR") over the path).

2. Relieving Congestion

The second strategy used by Enron's traders is to relieve system-wide congestion in the real-time market, which congestion was created by Enron's traders in the PX's Day Ahead Market. In order to relieve transmission congestion (i.e., the energy scheduled for delivery exceeds the capacity of the transmission path), the ISO makes payments to parties that either schedule transmission in the opposite direction ("counterflow payments") or that simply reduce their generation/load schedule.

Many of the strategies used by the traders involve structuring trades so that Enron gets paid the congestion charge. Because the congestion charges have been as high as $750/MW, it can often be profitable to sell power at a loss simply to be able to collect the congestion payment.

B. Representative Trading Strategies

The strategies listed below are examples of actual strategies used by the traders, many of which utilize the two basic principles described above. In some cases, the strategies are identified by the nicknames that the traders have assigned to them. In some cases, i.e., "Fat Boy," Enron's traders have used these nicknames with traders from other companies to identify these strategies.

1. Export of California Power

   a. As a result of the price caps in the PX and ISO (currently $250), Enron has been able to take advantage of arbitrage opportunities by buying energy at the PX for export outside California. For example, yesterday (December 5, 2000), prices at Mid-C peaked at $1200, while California was capped at $250. Thus, traders could buy power at $250 and sell it for $1200.

   b. This strategy appears not to present any problems, other than a public relations risk arising from the fact that such exports may have contributed to California's declaration of a Stage 2 Emergency yesterday.

2. "Non-firm Export"

a. The goal is to get paid for sending energy in the opposite direction as the constrained path (counterflow congestion payment). Under the ISO's tariff, scheduling coordinators that schedule energy in the opposite direction of the congestion on a constrained path get paid the congestion charges, which are charged to scheduling coordinators scheduling energy in the direction of the constraint. At times, the value of the congestion payments can be greater than the value of the energy itself.

b. This strategy is accomplished by scheduling non-firm energy for delivery from SP-15 or NP-15 to a control area outside California. This energy must be scheduled three hours before delivery. After two hours, Enron gets paid the counterflow charges. A trader then cuts the non-firm power. Once the non-firm power is cut, the congestion resumes.

c. The ISO posted notice in early August prohibiting this practice. Enron's traders stopped this practice immediately following the ISO's posting.

d. The ISO objected to the fact that the generators were cutting the non-firm energy. The ISO would not object to this transaction if the energy was eventually exported.

Apparently, the ISO has heavily documented Enron's use of this strategy. Therefore, this strategy is the more likely than most to receive attention from the ISO.

2. "Death Star"

a. This strategy earns money by scheduling transmission in the opposite direction of congestion; i.e., schedule transmission north in the summertime and south in the winter, and then collecting the congestion payments. No energy, however, is actually put onto the grid or taken off.

b. For example, Enron would first import non-firm energy at Lake Mead for export to the California-Oregon border ("COB"). Because the energy is traveling in the opposite direction of a constrained line, Enron gets paid for the counterflow. Enron also avoids paying ancillary service charges for this export because the energy is non-firm, and the ISO tariff does not require the purchase of ancillary services for non-firm energy.

c. Second, Enron buys transmission from COB to Lake Mead at tariff rates to serve the import. The transmission line from COB to Lake Mead is outside of the ISO's control area, so the ISO is unaware that the same energy being exported from Lake Mead is simultaneously being imported into Lake Mead. Similarly, because the COB to Lake Mead line is outside the ISO's control area, Enron is not subject to payment of congestion charges because transmission charges for the COB to Lake Mead line are assessed based on imbedded costs.

d. The ISO probably cannot readily detect this practice because the ISO only sees what is happening inside its control area, so it only sees half of the picture.

e. The net effect of these transactions is that Enron gets paid for moving energy to relieve congestion without actually moving any energy or relieving any congestion.

3. "Load Shift"

a. This strategy is applied to the Day-Ahead and the real-time markets.

b. Enron shifts load from a congested zone to a less congested zone, thereby earning payments for reducing congestion, i.e., not using our FTRs on a constrained path.

c. This strategy requires that Enron have FTRs connecting the two zones.

d. A trader will overschedule load in one zone, i.e., SP-15, and underschedule load in another zone, i.e., NP-15.

Such scheduling will often raise the congestion price in the zone where load was overscheduled.

The trader will then "shift" the overscheduled "load" to the other zone, and get paid for the unused FTRs. The ISO pays the congestion charge (if there is one) to market participants that do not use their FTRs. The effect of this action is to create the appearance of congestion through the deliberate overstatement of loads, which causes the ISO to charge congestion charges to supply scheduled for delivery in the congested zone. Then, by reverting back to its true load in the respective zones, Enron is deemed to have relieved congestion, and gets paid by the ISO for so doing.

e. One concern here is that by knowingly increasing the congestion costs, Enron is effectively increasing the costs to all market participants in the real time market.

f. Following this strategy has produced profits of approximately $30 million for FY 2000.

4. "Get Shorty"

a. Under this strategy, Enron sells ancillary services in the Day-ahead market.

b. Then, the next day, in the real-time market, a trader "zeroes out" the ancillary services, i.e., cancels the commitment and buys ancillary services in the real-time market to cover its position.

c. The profit is made by shorting the ancillary services, i.e., sell high and buy back at a lower price.

d. One concern here is that the traders are applying this strategy without having the ancillary services on standby. The traders are careful, however, to be sure to buy services right at 9:00 a.m. so that Enron is not actually called upon to provide ancillary services. However, once, by accident, a trader inadvertently failed to cover, and the ISO called on those ancillary services.

e. This strategy might be characterized as "paper trading," because the seller does not actually have the ancillary services to sell. FERC recently denied Morgan Stanley's request to paper trade on the New York ISO.

The ISO tariff does provide for situations where a scheduling coordinator sells ancillary services in the day ahead market, and then reduces them in the day-of market. Under these circumstances, the tariff simply requires that the scheduling coordinator replace the capacity in the hour-ahead market. ISO Tariff, SBP 5.3, *Buy Back of Ancillary Services.*

f. The ISO tariff requires that schedules and bids for ancillary services identify the specific generating unit or system unit, or in the case of external imports, the selling entity. As a consequence, in order to short the ancillary services it is necessary to submit false information that purports to identify the source of the ancillary services.

5. "Wheel Out"

a. This strategy is used when the interties are set to zero, i.e., completely constrained.

b. First, knowing that the intertie is completely constrained, Enron schedules a transmission flow through the system. By so doing, Enron earns the congestion charge. Second, because the line's capacity is set to "0," the traders know that any power scheduled to go through the inter-tie will, in fact be cut. Therefore, Enron earns the congestion counterflow payment without having to actually send energy through the intertie.

c. As a rule, the traders have learned that money can be made through congestion charges when a transmission line is out of service because the ISO will never schedule an energy delivery because the intertie is constrained.

6. "Fat Boy"

a. This strategy is described above in section A (1).

7. "Ricochet"

a. Enron buys energy from the PX in the Day Of market, and schedules it for export. The energy is sent out of California to another party, which charges a small fee per MW, and then Enron buys it back to sell the energy to the ISO real-time market.

b. The effect of this strategy on market prices and supply is complex. First, it is clear that Enron's intent under this strategy is solely to arbitrage the spread between the PX and the ISO, and not to serve load or meet contractual obligations. Second, Ricochet may increase the Market Clearing Price by increasing the demand for energy. (Increasing the MCP does not directly benefit Enron because it is *buying* energy from the PX, but it certainly affects other buyers, who must pay the same, higher price.) Third, Ricochet appears to have a neutral effect on supply, because it is returning the exported energy as an import. Fourth, the parties that pay Enron for supplying energy to the real time ex post market are the parties that underscheduled, or underestimated their load, i.e., the IOUs.

8. Selling Non-firm Energy as Firm Energy

a. The traders commonly sell non-firm energy to the PX as "firm." "Firm energy," in this context, means that the energy includes ancillary services. The result is that the ISO pays EPMI for ancillary services that Enron claims it is providing, but does not in fact provide.

b. The traders claim that "everybody does this," especially for imports from the Pacific Northwest into California.

c. At least one complaint was filed with the ISO regarding Enron's practice of doing this. Apparently, Arizona Public Service sold non-firm energy to Enron, which turned around and sold the energy to the ISO as firm. APS cut the energy flow, and then called the ISO and told the ISO what Enron had done.

9. Scheduling Energy To Collect the Congestion Charge II

a. In order to collect the congestion charges, the traders may schedule a counterflow even if they do not have any excess generation. In real time, the ISO will see that Enron did deliver the energy it promised, so it will charge Enron the inc price for each MW Enron was short. The ISO, however, still pays Enron the congestion charge. Obviously a loophole, which the ISO could close by simply failing to pay congestion charges to entities that failed to deliver the energy.

b. This strategy is profitable whenever the congestion charge is sufficiently greater than the price cap. In other words, since the ex post is capped at $250, whenever the congestion charge is greater than $250 it is profitable to schedule counterflows, collect the congestion charge, pay the ex post, and keep the difference.

C. ISO Tariff

The ISO tariff prohibits "gaming," which it defines as follows:

> "Gaming," or taking unfair advantage of the rules and procedures set forth in the PX or ISO Tariffs, Protocols or Activity Rules, or of transmission constraints in period in which exist substantial Congestion, to the detriment of the efficiency of, and of consumers in, the ISO Markets. "Gaming" may also include taking undue advantage of other conditions that may affect the availability of transmission and generation capacity, such as loop flow, facility outages, level of hydropower output or seasonal limits on energy imports from out-of-state, or actions or behaviors that may otherwise render the system and the ISO Markets vulnerable to price manipulation to the detriment of their efficiency." ISO Market Monitoring and Information Protocol ("MMIP"), Section 2.1.3.

The ISO tariff also prohibits "anomalous market behavior," which includes "unusual trades or transactions"; "pricing and bidding patterns that are inconsistent with prevailing supply and demand conditions"; and "unusual activity or circumstances relating to imports from or exports to other markets or exchanges." MMIP, Section 2.1.1 et seq.

Should it discover such activities, the ISO tariff provides that the ISO may take the following action:

1. Publicize such activities or behavior and its recommendations thereof, "*in whatever medium it believes most appropriate.*" MMIP, Section 2.3.2 (emphasis added).

2. The Market Surveillance Unit may recommend actions, including fines and suspensions, against specific entities in order to deter such activities or behavior. MMIP, Section 2.3.2.

3. With respect to allegations of gaming, the ISO may order ADR procedures to determine if a particular practice is better characterized as improper gaming or "legitimate aggressive competition." MMIP, Section 2.3.3.

4. In cases of "serious abuse requiring expeditious investigation or action" the Market Surveillance Unit shall refer a matter to the appropriate regulatory or antitrust enforcement agency. MMIP, Section 3.3.4.

5. Any Market Participant or interested entity may file a complaint with the Market Surveillance Unit. Following such complaint, the Market Surveillance Unit may "carry out any investigation that it considers appropriate as to the concern raised." MMIP, Section 3.3.5.

6. The ISO Governing Board may impose "such sanctions or penalties as it believes necessary and as are permitted under the ISO Tariff and related protocols approved by FERC; or it may refer the matter to such regulatory or antitrust agency as it sees fit to recommend the imposition of sanctions and penalties." MMIP, Section 7.3.

Committee on Governmental Affairs
EXHIBIT #A-58

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

NEWS RELEASE

NEWS MEDIA CONTACT:
Barbara A. Connors
(202) 208-0680

FOR IMMEDIATE RELEASE
August 23, 2000
Docket Nos. EL00-95-000 and EL00-98-000

COMMISSION ADDRESSES CALIFORNIA ELECTRICITY MARKETS, ORDERS INVESTIGATION

The Federal Energy Regulatory Commission today ordered a formal investigation of the electric rates and structure of California's Independent System Operator (ISO) and power exchange (PX) as well as market-based sellers in the California market.

The decision to launch a formal investigation was taken at this time so the process can be accelerated when the Commission staff concludes a previously announced nationwide fact-finding probe of electric markets and recent price spikes. The findings of the national probe will be presented to the Commission which will then decide on any formal action. Today's order directs staff to focus its investigation as soon as possible on California and the Western region and also launches the separate formal Commission investigation in California. The formal investigation will permit the Commission to take remedial action if rates are found to be unjust and unreasonable.

The California investigation comes in response, in part, to a complaint from San Diego Gas & Electric Company (SDG&E). It is appropriate, the Commission said, to investigate not only public utility sellers' rates in the ISO and PX but also the tariffs and agreements of the ISO and PX to determine whether market rules need to be modified.

Chairman James J. Hoecker commented: "SDG&E has asked us to limit what it believes to be excessive rates in the California wholesale market. We did that three weeks ago. Today, we affirm that action. This order demonstrates that the Commission is committed to reasonable rates for consumers of power. I believe we must pursue that goal vigorously within the limits of our authority. I therefore directed staff two weeks ago to accelerate the California portion of our national market investigation. And, I anticipate that at least one hearing pursuant to today's order will be held in San Diego. We do not find finger-pointing to be helpful at this juncture. Rather, the Commission recognizes the importance of getting all the facts before passing judgment on how this circumstance could have been avoided or what we must do to ensure that power markets function well in the future."

The Commission has said that while many of the factors that have contributed to recent increased prices in California's retail market are under the jurisdiction of state regulators, the Commission is committed to working with California officials to ensure that consumers have an efficient, affordable and reliable electric power market.

In addition to the new investigation, today's action denies the San Diego utility's request for an immediate broad \$250 per MWh price cap on all sellers in California. SDG&E did not present evidence that all potential sellers in California have market power, nor did it show why a broad price cap would be an appropriate response, the Commission said. Importantly, however, although today's order finds that immediate seller price caps were not justified on the existing record, the order does not disturb the California ISO's recent decision to set its maximum purchase price cap for imbalance energy and ancillary services at \$250 per MWh. The ISO's actions to change purchase price caps were sustained in an order issued by the Commission three weeks ago. The ISO purchase price caps will mitigate pricing volatility and serve to discipline prices in both the ISO and the PX, the Commission explained.

The national investigation was ordered July 26 to determine if the electricity markets are operating efficiently as the industry transitions to a more competitive marketplace.

Earlier this month, Chairman Hoecker, in a letter to California Governor Gray Davis, assured the Governor that the Commission is committed to finding solutions to Californians' concerns about electricity prices. Last week, the Commission's General Counsel Douglas Smith testified in California that the Commission is working with California officials and emphasized the Commission's ongoing investigation into electric bulk power markets. Daniel Larcamp, the head of the Commission's Office of Markets, Tariffs and Rates, will participate in a hearing scheduled by the California Public Utilities Commission in San Diego this week.

UNITED STATES OF AMERICA92 FERC ¶ 61,172
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. Docket No. EL00-95-000

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

Respondent.

Investigation of Practices of the California Independent System Operator and the California Power Exchange Docket No. EL00-98-000

ORDER INITIATING HEARING PROCEEDINGS TO INVESTIGATE JUSTNESS AND REASONABLENESS OF RATES OF PUBLIC UTILITY SELLERS IN CALIFORNIA ISO AND PX MARKETS AND TO INVESTIGATE ISO AND PX TARIFFS, CONTRACTS, INSTITUTIONAL STRUCTURES AND BYLAWS; AND PROVIDING FURTHER GUIDANCE TO CALIFORNIA ENTITIES

(Issued August 23, 2000)

On August 2, 2000, San Diego Gas & Electric Company (SDG&E) filed a complaint pursuant to Rule 206 of the Commission's Rules of Practice and Procedure [1] asking the Commission for an emergency order capping at $250 per MWh the prices at which sellers subject to its jurisdiction may bid energy or ancillary services into the markets operated by the California Independent System Operator (ISO) and the

[1] 18 C.F.R. § 385.206 (2000).

California Power Exchange (PX). SDG&E seeks an amendment to the market-based rate schedules of all sellers into the markets operated by the ISO and PX to restrict their bids into those markets. [2] SDG&E requests that the Commission act as quickly as possible on the merits of its complaint.

In this order, as discussed below, we are denying SDG&E's requested immediate imposition of a price cap on all sellers in California.[3] However, we are instituting consolidated hearing [4] proceedings pursuant to section 206 of the Federal Power Act to investigate the justness and reasonableness of the rates and charges of public utilities that sell energy and ancillary services to or through the California ISO and PX, and to also investigate whether the tariffs and institutional structures and bylaws of the California ISO and PX are adversely affecting the efficient operation of competitive wholesale electric power markets in California and need to be modified. In light of the fact that many of the same issues raised here are also the subject of a fact finding staff investigation ordered by the Commission on July 26, 2000, we intend to issue a further order after the Commission reviews the outcome of the staff investigation related to California markets to take into account the staff investigation findings, as appropriate, and to address or further refine the issues set for hearing herein, as appropriate.[5]

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[2]SDG&E states that it would be impracticable to list all such sellers in its complaint. It states that it served the complaint on all parties to various Commission proceedings involving California pricing and restructuring issues, including Docket Nos. ER98-2843, ER99-4462, EL00-91, ER96-1663, and EC96-19. It states that it also requested the ISO to distribute it electronically to the ISO's list of market participants.

[3]However, we are not disturbing the California ISO's decision to set its purchase price cap at $250/MWh, see, Morgan Stanley Capital Group Inc. v. California Independent System Operator Corp., 92 FERC ¶ 61,112 (2000).

[4]Hearings under section 206 may take the form of a proceeding before an administrative law judge or a hearing directly before the Commission. A hearing before the Commission may include written and/or oral presentation of evidence and arguments. We do not in this order determine which type of proceeding that will be required.

[5]The section 206 proceeding we are initiating here differs from the staff investigation in several respects. A section 206 investigation initiates a formal evidentiary process where all interested parties are assured an opportunity to present evidence and arguments on the record before the Commission. In addition, it provides a (continued...)

Our goal in these proceedings is to detect and, to the extent within our jurisdiction, to resolve as expeditiously as possible, any defects in the operation of competitive power markets in California. To the extent market performance issues surface in our staff investigation or the section 206 investigation that concern the structure or independence of the ISO, the Commission will also take up these issues to the extent they are present in any RTO proposal that is filed on January 16, 2001, pursuant to Order No. 2000. [6]

SDG&E's Complaint

SDG&E states in its complaint that since the restructured electric market began operation in California in April 1998, the three large investor-owned utilities in the state transferred operational control of their transmission facilities to the ISO, and began purchasing all of the energy needed to serve their retail customers through the PX. SDG&E states further that because it has completed recovery of certain stranded generation costs, the retail rate caps imposed by state statute no longer exist for it, although they are still in place for the other two investor-owned utilities.

SDG&E asserts that since the beginning of June 2000, wholesale electric prices in California have at times exceeded, often by a multiple of three or four, prices seen at comparable load levels in prior years. SDG&E cites to data showing that the PX day-ahead price for Southern California never exceeded $250 in June and July of 1999, but equaled or exceeded that level in 167 hours in 2000. SDG&E attributes this to "dysfunctional" wholesale markets, particularly at high demand levels, that allow sellers

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[5](...continued)
statutory mechanism for the Commission to exercise its remedial powers to change the rates, terms and conditions of jurisdictional services that are determined to be unjust, unreasonable, unduly discriminatory or preferential and, if appropriate, to order refunds. By establishing the proceeding in this order, the Commission ensures that its remedial authorities under Section 206 will be available at the earliest time permitted under the Federal Power Act.

[6]Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (2000), FERC Stats. & Regs. ¶ 31,092 (2000), petitions for review pending sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC, Nos. 00-1174, et al.

to exact prices considerably above levels that would prevail in a more fully competitive market.

SDG&E is critical of what it calls the "de-centralized" market structure and design in California, stating that the market is not capable of supplying the electricity needs of consumers at competitive prices. SDG&E states that the Commission has already seen fit to intervene when it found that the ISO's congestion management system is in need of overhaul or replacement. [7] SDG&E argues that although the Commission did not design California's market, it has a statutory responsibility to lead the effort to fix the problems and protect consumers in the interim until reforms are in place.

SDG&E contends that the Commission's market-based rate authorizations were based on the necessary premise that the sellers lack market power and that the markets into which they are selling are workably competitive. SDG&E asserts that the energy and ancillary services markets in California are not workably competitive, at least when state-wide demand reaches 33,000 MW, and at such demand levels, wholesale prices are no longer reasonable. SDG&E asks that any seller's market-based rate authority "should be conditioned to provide that, unless or until the Commission finds that the bulk power markets for energy and ancillary services in California are workably competitive, such seller shall not submit a bid of more than $250 per MWh to supply energy or ancillary services into markets operated by the ISO or PX." SDG&E requests that the Commission act as quickly as possible on its complaint.

Notice and Pleadings

Notice of SDG&E's filing was published in the Federal Register, 65 Fed. Reg. 48,693 (2000), with comments, protests, and motions to intervene due on or before August 14, 2000.

The Public Utilities Commission of California (California Commission) filed a notice of intervention supporting SDG&E's request for a $250 bid cap and asking that such caps remain in place until the Commission finds based on an evidentiary hearing that workable competition exists in California and western energy and capacity markets. Pacific Gas and Electric Company and Southern California Edison Company filed motions to intervene and stated positions in support of the complaint. The Utility Reform Network filed a late motion to intervene in support of the complaint.

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[7] Citing California Independent System Operator Corp., 90 FERC ¶ 61,006 (2000).

Answers in opposition to the complaint were filed by Dynegy Power Marketing, Inc., El Secunda Power, LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC, (jointly); Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (jointly); and by Enron Power Marketing, Inc. and Enron Energy Services, Inc. (jointly). Reliant Energy Power Generation, Inc. filed an answer in opposition to the complaint and a motion to file it one day out-of-time. Merrill Lynch Capital Services, Inc. filed a motion to intervene and answer in opposition. New York Mercantile Exchange, Morgan Stanley Capital Group Inc., Duke Energy North America LLC (together with Duke Energy Trading and Marketing, LLC and Duke Energy Merchants, LLC), Williams Energy Marketing & Trading Company, and Independent Energy Producers Association filed motions to intervene and protests.

The ISO filed a motion to intervene, answer, and request for summary rejection of the complaint. The PX filed a motion to intervene with comments noting the existence of its hedging products and disputing that the separation of the ISO and PX is a fundamental impediment to competition. The following filed motions to intervene and stated a position in opposition to the complaint: Electric Power Supply Association; Western Power Trading Forum; Portland General Electric Company; Automated Power Exchange, Inc.; and Northern California Power Agency (agrees with allegations but opposes price cap).

The following filed motions to intervene raising no issues: California Electricity Oversight Board; El Paso Merchant Energy, L.P.; the cities of Redding, Santa Clara, and Palo Alto and the M-S-R Public Power Agency; Arizona Districts; PPL EnergyPlus, LLC and PPL Montana, LLC; California Manufacturers and Technology Association; Sacramento Municipal Utility District; Metropolitan Water District of Southern California; California Department of Water Resources; Modesto Irrigation District; and Transmission Agency of Northern California. In addition, a number of individuals filed brief letters of comment on the complaint.

Discussion

A. Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[8] the notice of intervention and the timely, unopposed motions to intervene serve to make those who filed them parties to this proceeding. In addition, those respondents filing answers to the complaint are parties. We will accept the late-filed pleadings.

B. Rejection of Immediate Seller Price Cap and Institution of Hearing on Seller Rates, ISO and PX Tariffs and Market and Institutional Design

The Commission is very concerned about the impact of significant increases in retail electricity rates on residents and businesses in San Diego. We note that a number of factors have interacted to lead to these rate increases, and that many of the factors that contributed to these increases fall within the jurisdiction of state regulators and are not within the jurisdiction of the Commission, including, (1) siting of new generation and transmission facilities, (2) lack of demand-side programs that allow consumers and businesses to receive and respond to price signals, (3) rules under which SDG&E provides retail electric service which limit its actions as a purchaser of wholesale power (e.g., requirements that SDG&E make all purchases through a single power exchange and restrictions on SDG&E's ability to enter into wholesale supply or risk management agreements that could protect against excessive volatility in wholesale commodity prices), and (4) retail rate designs that do not offer retail customers of SDG&E the option to arrange for stable, levelized rates. And, of course, the severe weather which has blanketed the West and exacerbated the generation supply shortage that exists in California is beyond the control of any public body.

The Commission does have jurisdiction over wholesale electric prices and a role in determining whether and to what extent factors related to wholesale electric markets might have contributed to the increase in retail electric rates in San Diego. We take seriously volatile price increases during high load periods in California and allegations that the markets are not functioning properly. According to SDG&E, prices in June and July of 1999 rarely exceeded $150/MWh, while prices for the same period in 2000 exceeded $250/MWh in 167 hours and $500/MWh in 59 hours. SDG&E contends that these higher prices come at a time when load levels for 2000 are below the peak levels of 1999. SDG&E argues that even accounting for this year's higher natural gas prices, energy and ancillary services prices during June and July of 2000 greatly exceed the operating costs of a typical Southern California gas-fired generating unit. SDG&E concludes that the markets cannot be workably competitive if sellers are able to exact

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[8] 18 C.F.R. § 385.214 (2000).

prices that are considerably above levels that would prevail in open competition, i.e., sellers are able to bid and receive prices significantly above their marginal costs. SDG&E also argues that the hour-to-hour volatility in imbalance energy prices and the erratic clearing price for ancillary services is an indication that the market is breaking down when it is moderately stressed.

In addition, numerous reports prepared by the independent monitoring bodies of the PX and ISO indicate that the current market in California experiences problems during tight supply/high demand periods such that it may not yield just and reasonable rates. These reports indicate that, despite significant increases in demand, there has been no corresponding increase in the construction of new generation. Given the lack of any meaningful demand response, this means that virtually all bids must be accepted when these shortage conditions arise. In addition, these reports indicate that most of the load in California is being met through spot market wholesale purchases rather than longer-term power sale contracts and hedging arrangements that could provide price certainty and stability. As a result of all these factors, there are periods when all generation must be accepted, regardless of the bid price, and sellers may be in a position to act on this knowledge and raise bids above the level that would be expected solely as a result of scarcity.

For all of these reasons, we conclude that a further formal investigation is appropriate to determine why anomalous prices occur at certain times, whether certain market or institutional factors cause the anomalous prices, and whether the anomalous prices are unjust, unreasonable, unduly discriminatory or preferential. While SDG&E has focused on the performance of sellers in the market, the action of sellers may in part be caused by the current market rules and institutional structures. Accordingly, we conclude that it is appropriate to investigate not only the justness and reasonableness of public utility sellers' rates in the PX and ISO markets but also to investigate the tariffs and agreements of the ISO and PX to determine whether market rules or institutional factors embodied in those tariffs and agreements need to be modified.

We note that all of the markets operated by the ISO and PX markets are highly inter-related and largely served by the same generating units. The rules for pricing and bidding for any one market can affect the price and quantity bid into any of the other markets. Consequently, a poorly designed market not only can distort prices for its own participants but can also create high opportunity costs to participants in other markets that may, by themselves, be well-designed and functioning properly.

While we find it appropriate to institute a section 206 hearing on these issues, we cannot implement an immediate price cap of $250/MWh as requested by SDG&E because there is no record before us to support such an action. 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. While the issues raised by this complaint are important, the Commission has no basis to conclude that SDG&E's proposal to place an immediate, arbitrary $250/MWh cap on the price that every public utility seller of energy and ancillary services may bid into the PX and ISO markets would satisfy this standard. SDG&E has provided no evidence to demonstrate that all potential sellers are able to exercise market power, has not documented a single instance of a seller exercising market power during times of scarcity, and did not attempt to show that the conditions underlying the Commission's approval of market-based rates for public utility sellers of energy and ancillary services have changed. Nor did it address specific market or institutional factors that may be causing rates to be unjust or unreasonable. In addition, the ISO's analysis raised concerns that a cap at this level would call into question the ISO's ability to attract sufficient supply to meet the totality of California loads, and SDG&E has not provided any basis for the Commission to evaluate the reliability impacts of adopting a $250/MWh seller's bid cap. In sum, SDG&E has not met the burden of showing that an immediate, universal bid cap on all potential sellers supplying energy and ancillary services into the PX and ISO markets is justified and in the public interest.

Although we have concluded that immediate seller price caps have not been justified based on the existing record, we have not disturbed the actions taken by the California ISO, in its discretion as a purchaser of imbalance energy and ancillary services, to set its purchase price cap at $250/MWh. This action addresses SDG&E's concern that pricing volatility be mitigated. While the ISO's authority to implement this cap expires in November 2000, the ISO has recently stated that it will make a timely filing with the Commission to extend its authority. In addition, while only the ISO's markets are directly affected by its recent action, the ISO purchase price caps currently permitted by the Commission will serve to discipline prices in both the ISO and PX. We disagree with SDG&E that the effect of the maximum purchase price that the ISO will pay for energy and ancillary services on prices in the PX market is only indirect. The ISO sets a maximum purchase price at $250/MWh and the evidence to date indicates that the unconstrained PX clearing price has not exceeded the maximum purchase price set for ISO imbalance energy (currently $250/MWh) plus the rate for replacement reserves ($100/MWh) for under-scheduled load. Buyers in the PX submit conditional bids. They offer to purchase energy and ancillary services from the PX at a price at or near the ISO's maximum purchase price because they know that if their bids are not accepted in the PX, they may still buy energy and ancillary services at the maximum purchase price in the ISO's real-time market. Thus, the ISO's maximum purchase price effectively disciplines prices in the PX markets.

C. Congestion Management and Market Redesign

SDG&E asserts that the ISO's congestion management and market structures are flawed and in need of overhaul. In support of its assertion, SDG&E points to an order issued by the Commission on January 7, 2000, in which the Commission directed the ISO to file replacement congestion management and market approaches. [9] Furthermore, SDG&E expresses its concern that, for a number of reasons, the congestion management and market reform efforts being pursued by ISO stakeholders will not produce meaningful results. SDG&E indicates that it is prepared to work with the ISO to develop alternative reform proposals; [10] however, SDG&E's complains that the ISO stakeholder process has, in SDG&E's judgment, been ineffective with respect to these issues.

Various interveners contend that SDG&E's arguments are premature. In particular, the ISO notes that in initiating the ISO's market redesign, the Commission stated that it should be pursued with input from all stakeholder groups, and it argues that SDG&E is attempting to circumvent that process. [11]

We agree with Interveners. In California ISO, the Commission found the ISO's existing congestion management structure to be flawed, and, on that basis, we directed the ISO to develop and submit to the Commission a comprehensive congestion management and market redesign. Moreover, as noted by the ISO, we stated that such a redesign should be pursued with input from all stakeholder groups, as well as from the ISO's Market Surveillance Committee. The reform efforts have been the subject of extensive public review and comment and are nearing completion. Accordingly, we reject

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[9] See California Independent System Operator Corp., 90 FERC ¶ 61,006 (2000) (California ISO).

[10] Notably, SDG&E indicates its preference that the ISO adopt the market and congestion management structures currently in use by the PJM and New York Independent System Operators. SDG&E at 7.

[11] ISO Answer at 6, citing California ISO, 90 FERC at 61,014.

SDG&E's arguments at this time. We will defer any consideration on the merits of the ISO's reform efforts until the earlier of the ISO's filing of its reform proposal or the date which the Commission issues a supplemental order in this proceeding.

D. Other Available Methods to Reduce Impact of Spot Market Volatility

SDG&E cites a number of problems that contribute to produce the unsatisfactory results facing its retail customers, including its exposure to spot market price volatility. In its complaint, SDG&E states that under California's restructuring policy it remains a "default" service provider for residential customers that have not chosen other energy service providers. SDG&E states that it will continue until directed otherwise to provide service to these customers by passing through the PX and ISO spot market wholesale price.

According to many of the comments, SDG&E has chosen not to purchase risk management tools that were and are available and that would have provided price certainty during periods of short supply. Furthermore, SDG&E appears to be the only major investor-owned utility in California that had not sought state commission authority to hedge its price risks through forward contracts which are designed to "lock-in" a specific price in advance of spot or real-time market activities. We note that other Interveners argue that the price cap proposal will penalize those market participants that hedged against price volatility relative to those market participants that chose to remain exposed to the spot markets. They argue that SDG&E should not be sheltered for the consequences of its decision not to protect its retail customers and remaining fully exposed in the spot market, when other participants made decisions to hedge their risks.

It is unclear whether SDG&E's failure to purchase hedging instruments for its retail operations is due to state regulatory policies or its business decisions. A retail rate design that exposes consumers to the volatility of commodity prices would be extraordinary, particularly when consumers do not have the ability to receive or respond to price signals. While the Commission has no authority over retail electricity rates nor authority to rule on the prudence of SDG&E's provision of retail electric service, we would expect any responsible retail supplier to rely on a portfolio of resources and to turn to the spot market only to engage in economy transactions or to meet portions of its load that could not be predicted well in advance or which were not anticipated due to resource outages greater than are covered by prudent reserves. We note that responsible hedging in the forward markets will greatly reduce price volatility for SDG&E's retail customers even within the limits established by the California Commission. [12] The Commission has approved a number of recent filings by the Cal PX and its Cal PX Trading Services (CTS) division that enhance and expand wholesale forward market services (e.g., block forward contracts for balance-of-the-month, monthly and multi-year). We encourage SDG&E to discuss with the California Commission the use of all available hedging tools to prudently manage the price risks associated with the retail market.

E. Other Market Reforms

The record indicates that a current market problem is underscheduling of loads and generation in the Cal PX Day ahead and Hour Ahead markets. In some hours as much as 25 percent of system needs were met in the ISO real-time market. This significant level of under-scheduling is largely attributable to the different market incentives faced by buyers and sellers. We are concerned that this increasing level of market activity in the real-time market raises significant reliability and economical concerns. For example, if there is insufficient supply in the ISO markets, then the ISO must procure additional supplies out-of-market (OOM) at the last minute in order to meet its needs for the operating day. Historically, the ISO procures on a daily basis only the resources needed for the operating day. Not only does this procurement practice put pressure on the grid operator to secure needed resources at the last minute, but the practice is uneconomical. Such spot-market purchases are not subject to the ISO's buyer's cap. Furthermore, because the ISO is the supplier of last resort for these services, when OOM calls are made, suppliers realize that the ISO is in a must-buy situation.

In an effort to address this problem, we direct the ISO to immediately institute a more forward approach to procuring the resources necessary to reliably operate the grid. Specifically, the ISO should anticipate the need for such additional resources based on forecasted peak periods. We direct the ISO to factor these reforms into an analysis of the need for and level of purchase price caps and to include this analysis as support for any filing it makes to extend its purchase price cap authority.

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[12]For example, SDG&E currently has the ability to obtain a hedged position in the wholesale market at a price below $60/MWh. Morgan Stanley at 4.

F. Refund Effective Date

In cases where the Commission institutes a proceeding on complaint under section 206 of the Federal Power Act, section 206(b) requires that the Commission establish a refund effective date that is no earlier than 60 days after the filing of the complaint, but no later than five months subsequent to the expiration of the 60-day period. In cases where the Commission institutes a section 206 proceeding on its own motion, section 206(b) requires that the Commission establish a refund effective date that is no earlier than 60 days after publication of notice of the Commission's intent to institute a proceeding in the Federal Register, and no later than five months subsequent to the expiration of the 60-day period. We will establish the refund effective date in Docket Nos. EL00-95-000 and EL00-98-000 60 days from the date on which notice of our initiation of the investigation in Docket No. EL00-98-000 is published in the Federal Register.

We note that although the Commission is statutorily required to establish a refund effective date whenever it institutes a proceeding under section 206 of the FPA, it is not required to order refunds at the end of the proceeding. [13] Refunds are discretionary. Moreover, any attempt to establish a just and reasonable price to serve as the basis for a refund calculation would be extremely difficult to the extent that it would require the Commission to reconstruct economic decisions that would have been made under different circumstances. In addition, in the context of market-based rates and a competitive market, refunds may not be the appropriate remedy to address any competitive problems that may be found. Thus, in establishing a refund effective date in these dockets, we wish to emphasize that, while refunds would ultimately offer some level of restitution to California ratepayers, they may be an inferior remedy from a market perspective and not the fundamental solution to any problems occurring in California markets. Further, we are cognizant of the effect that potential refund liability could have

[13]Under section 206, if the Commission finds that any public utility's rates, charges or classification, is unjust, unreasonable, unduly discriminatory or preferential, it shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. Section 206 provides that at the conclusion of the proceeding, the Commission may order a public utility to make refunds of any amounts paid for the period subsequent to the refund effective date through a date 15 months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate the Commission orders to be thereafter observed and enforced.

on public utility sellers in the California ISO and PX markets and we emphasize that while we must protect ratepayers, we also do not intend to undermine the financial stability of public utility sellers. We emphasize these points not to prejudge the issue of whether the Commission will find it appropriate to order refunds, but rather to ensure that all parties are aware of the statutory framework and the complexity of the issues raised in this proceeding. Any decision whether or not to impose refund obligations will be based on our findings regarding just and reasonable rates and a balancing of consumer and investor interests.

G. Consolidation and Further Orders

Because Docket Nos. EL00-95-000 and EL00-98-000 raise common issues of law and fact, we will consolidate them for purposes of hearing and decision. Accordingly, any party who has moved to intervene in Docket No. EL00-95-000 will be considered to be a party to the consolidated proceeding. We shall also issue further orders in this proceeding after we consider information related to California markets to be provided by the staff investigation ordered on July 26, 2000. In our July 26, 2000 Order Directing Staff Investigation, the Commission directed staff to undertake a fact-finding investigation of the conditions in electric bulk power markets (including volatile price fluctuations) in various regions of the country and report its findings to the Commission by November 1, 2000. Because of recent events in the ISO and PX markets, we will direct staff to focus on the California and Western region as soon as possible. By having the benefit of the fact-finding results, we will be better able to further narrow the focus of the hearing ordered herein, as appropriate.

The Commission orders:

(A) SDG&E's request for the imposition of a price cap on sellers into the California markets is hereby denied as discussed in the body of this order.

(B) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly section 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held in Docket Nos. EL00-95-000 and EL00-98-000 concerning the justness and reasonableness of the rates, charges, and practices of public utility sellers of wholesale power into the California ISO and PX markets and of the California ISO and PX tariffs, agreements and institutions, as discussed in the body of this order.

(C) The hearing ordered in Ordering Paragraph (B) above shall be held in abeyance pending a further Commission order, as discussed in the body of this order.

(D) Docket Nos. EL00-95-000 and EL00-98-000 are hereby consolidated for the purposes of hearing and decision.

(E) The Secretary shall promptly publish in the Federal Register a notice of the Commission's initiation of section 206 proceedings in Docket No. EL00-98-000, and we direct the ISO and PX to electronically serve this notice upon their respective list of market participants and to immediately post a copy of this order on their webpages.

(F) The refund effective date in Docket Nos. EL00-95-000 and EL00-98-000, established pursuant to section 206(b) of the Federal Power Act, will be 60 days following publication in the Federal Register of the notice discussed in Ordering Paragraph (E) above.

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

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

Linwood A. Watson, Jr.,
Acting Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company

Complainant,

v.

Docket No. EL00-95-000

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

Respondent.

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

Docket No. EL00-98-000

(Issued August 23, 2000)

MASSEY, Commissioner, dissenting in part:

There is a crisis of confidence in California wholesale electricity markets that threatens to erode the political consensus necessary to sustain a market-based approach to regulation. In these circumstances, the Federal Energy Regulatory Commission must act forcefully and decisively to reassure California market participants, policymakers and consumers that federal regulators will insist that jurisdictional wholesale markets produce consumer benefits and just and reasonable rates. I would grant the relief requested in the complaint and would cap bids into the California ISO and PX markets at $250/Mwh [1] as a temporary stopgap measure pending the outcome of the section 206 investigation

[1] In order to provide the ISO with the flexibility to maintain reliability, I would not apply the bid cap to Out of Market calls to out of state generator resources or to energy payments in the Summer 2000 Demand Relief Program currently in effect.

initiated by today's order. I am convinced that such a cap is necessary to ensure just and reasonable rates during our investigation. [2]

In recommending that a price cap be put in place now, I am motivated by a deep concern about the high prices in wholesale markets in California. The Commission has a statutory duty to ensure that wholesale prices are just and reasonable. This is the Commission's fundamental consumer protection responsibility, and the Federal Power Act provides no exception for poorly functioning markets. Indeed, the Commission's primary rationale for promoting market-based policies has been that markets would produce consumer benefits and lower prices compared to cost of service regulation.

There are sufficient indications in this record that California wholesale markets are not producing prices that are just and reasonable. California wholesale electricity costs for June 29 of this year were seven times what they were for the same date in 1999 ($340 million vs. $45 million) even though energy usage was only about 3% more. [3] Southern California Edison states that during the month of June, 2000, the total cost of electricity (energy and ancillary services combined) charged to the California market was nearly half of California's total electricity cost for all of 1999. In two separate five-day periods in June, 2000 (when demand was at least 3,000 MW to 5,000 MW below the projected annual peak) California's total cost of electricity exceeded $1 billion, with one of those five day periods reaching $1.3 billion .[4] SDG&E provides a comparison of final PX day-ahead prices for the Southern California zone for June and July during 1999 and 2000. During June and July of 1999, prices rarely exceeded $150/MWh even during the highest load levels. During the same period this year, prices have multiplied to three and

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[2] The majority order notes that the ISO's existing $250/MWh purchase price cap effectively limits bids into California, and this appears to be true. Rather than rely totally upon the ISO for temporary price relief, however, this Commission must take firm responsibility for prices in jurisdictional wholesale markets. In most other respects, I agree with the conclusions reached by the majority order. In particular, I endorse opening an expedited section 206 investigation and setting the earliest possible refund effective date, although I disagree with the portion of the text that appears to characterize the prospects for refunds as unlikely. In any event, if refunds are unlikely, it is even more incumbent upon the Commission to ensure that unreasonably high prices are mitigated during the pendency of our investigation.

[3] See Attachment B to Notice of Intervention of the Public Utilities Commission of the State of California.

[4] Motion to Intervene and Response of Southern California Edison Company.

four times the levels reached last year whenever load levels exceed 33,000 MW, according to SDG&E. [5] The California Public Utilities Commission states that every analysis of the California markets since their opening has found substantial exercise of market power. [6] In these circumstances, the confidence of California consumers in wholesale markets may quickly erode.

The record supports the conclusion that during periods of high demand in California, generator bid prices are virtually unrestrained by the forces that would apply in competitive markets for other commodities. In other markets besides electricity, when the price is too high, consumers purchase less and this in turn has a substantial dampening effect on price. In the California wholesale electricity markets, the willingness of purchasers is largely unaffected by price, and sellers understand this dynamic. In fact, the ISO's Department of Market Analysis concluded that when demand exceeds 40 GW "there is no constraint on how high [generators] might raise their prices in the absence of price caps." [7]

This lack of demand responsiveness appears to have the strong tendency to influence generator bids sharply higher. In high usage hours where no market forces restrain an unbridled price runup, a large transfer of wealth from purchasers to sellers can occur rapidly because all sellers are paid the highest market clearing price. The high prices that wholesale purchasers pay are ultimately passed through to retail consumers, either immediately or over some period of time. [8]

The complainant and interveners identify other serious problems as well in California wholesale markets. The siting of generation is lagging rather sharp increases in demand, which makes it likely that during peak usage all generator bids, regardless how high, must be accepted. There is limited transfer capacity over high voltage transmission wires into California. There have been very limited hedging and forward contracting by wholesale purchasers who have been required by state policy to make the bulk of their purchases through the ISO and PX spot markets. Serious questions are raised about the wisdom of the somewhat unique California market design, required by

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[5] Complaint of San Diego Gas & Electric Company.

[6] Notice of Intervention of the Public Utilities Commission of the State of California, at 8.

[7] Id., at 7.

[8] Narragansett Electric Co. v. Burke, 381 A.2d 1358 (1977), cert. denied, 435 U.S. 972 (1978). Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953 (1986).

state law, that provides for separate ISO and PX markets. In addition, this Commission has already declared that the ISO's current congestion management system must be completely overhauled.

I do not believe that customers must be required to bear the full economic brunt of the poorly functioning market and high prices that these problems create. I am pleased that the Commission is launching a section 206 investigation, and it is my hope that we will leave no stone unturned in investigating and proposing market-based solutions that will lead to just and reasonable prices.

I must point out, however, that neither the FERC nor state policymakers, acting in isolation from each other, can solve all of these market flaws because our respective jurisdictions are sharply delineated under existing law. State policymakers cannot effectively define or police market power in interstate wholesale markets. They cannot require a wholesale market structure, based upon an efficiently operating interstate transmission grid, that will produce just and reasonable rates. These are federal responsibilities. By the same token, under existing law the FERC cannot site the generation and transmission facilities that are necessary to bring supply and demand into equilibrium, and has no direct authority to require purchasers of power to hedge price volatility risk in forward or financial markets. These are state responsibilities. Both federal and state policymakers have a role in pursuing policies that will facilitate an effective and price-dampening demand side response (where, for example, customers bid "negawatts" into the market).

In short, high prices in California may not ultimately be reduced without a joint effort by federal and state policymakers. We must work together to solve the problems at hand, including joint proceedings and hearings as appropriate.

I would not recommend a $250/MWh bid cap as a long term solution to these market flaws. I am very much aware that the installation of additional generation facilities is a key part of the solution in California, and our policies must not discourage that investment. Nevertheless, I am convinced that this temporary price cap is necessary pending the implementation of measures to ensure that California wholesale markets produce just and reasonable rates.

For these reasons, I respectfully dissent in part to today's order.

William L. Massey
Commissioner

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company

v. Docket No. EL00-95-000

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 Docket No. EL00-98-000

(Issued August 23, 2000)

HÉBERT, Commissioner, *concurring:*

I write separately to explain my position on one of the issues raised in today's order. In my opinion, California consumers are not adequately served by the Commission's selection of possible refund relief. If it were up to me, I would refrain from adopting a refund effective date. If a refund effective date were in fact required by the Commission's institution of a proceeding under section 206, as amended by the Regulatory Fairness Act, I would choose a different refund effective date. Specifically, I would select the latest possible refund effective date (7 months from the date of publication of the investigation in EL00-98-000 in the Federal Register) rather than the earliest date (60 days from the date of Federal Register publication).

I understand that the selection of a later refund effective date would be contrary to the Commission's standard practice, repeated here, of selecting the earliest possible date. In the present circumstances, however, the interest of California consumers justifies a departure from standard practice. That is because the Commission's investigation of practices of the California ISO and PX is tied to its ongoing investigation of wholesale power practices throughout the United States. The Commission is unlikely to conclude either of its investigations prior to the refund effective date instituted in today's order. That means that in the intervening period -- after the refund effective date but before the conclusion of the Commission's investigations -- wholesale power suppliers into California markets will not know for certain the price they ultimately will be allowed to recover.

I appreciate the language in today's order, slip op. at 12-13, that indicates that refunds may not represent an appropriate remedy, in the context of market-based rates and competitive markets, to address any identified competitive problems. Nevertheless, the fact remains that a later refund order remains a possibility, no matter how remote. This looming contingency will deter power suppliers from entering capacity-starved California markets. The possibility of a retroactive price adjustment, just like the imposition of price caps, acts to undermine precisely the type of reliability of service and robustness of competitive markets that the Commission (and all market participants) claim to vigorously support.

Consumers are best served by regulatory policies that promote market entry and ensure that electricity supply will be available to meet demand. Directives from regulators and politicians to make refunds or release emergency funds may offer some relief in the short-term. In the long-term, however, electricity consumers can be assured of low prices and reliable service only if entrepreneurs have the motivation to build plants and string wires. Without badly-needed capital investment, capacity-limited regions such as southern California will continue to lurch uncertainly from summer to summer.

In all other respects, I agree with the determinations of the Commission in today's order.

Therefore, I respectfully concur.

Curt L. Hébert, Jr.
Commissioner

CALIFORNIA ISO

Report on California Energy Market Issues and Performance: May-June, 2000

Special Report

Prepared by the Department of Market Analysis
California Independent System Operator
August 10, 2000

Table of Contents

Summary of Findings and Recommendations

In late May and June of this year, prices in the California energy markets were significantly higher than expected. Prices in the Power Exchange's Day Ahead market and the ISO's real time energy market reached the ISO's $750 price cap during many hours. The ISO's Department of Market Analysis (DMA) examined market activity during these two months to determine the underlying causes for the high wholesale prices. DMA found that the high prices were the result of the combination of several factors, including (1) unusually high demand for electricity region-wide due to unseasonably high temperatures and recent economic growth, (2) a doubling of gas prices over the last year, and (3) the fact that no significant new supply has been added in California in recent years. The combination of very tight supply and demand conditions — in conjunction with very limited ability of consumers to reduce consumption in response to rising prices — created absolute shortages of supply, as well as the opportunity for the exercise market power during many hours. The exercise of this market power further inflated wholesale prices well above levels that would have resulted under competitive market conditions.

The performance of the ISO markets over the past two years has shown that workable competition has existed for most hours of the year (i.e. for all but about 1 to 2% of total annual hours). During those hours, supply has been sufficient to cause competition among suppliers. Our findings show that when workable competition exists, prices tend to be close to the short-run variable cost of the highest-cost generating unit required to meet demand. However, during high load hours, the combination of tight supply conditions and the limited ability of consumers to reduce consumption in response to prices creates the situation in which any firm that owns a significant share of the generation serving the state can exercise market power to inflate wholesale prices.

While California has experienced robust economic growth during the past decade, there has been very little investment in new generation and transmission within California over the last 15 years. As a result, the ample reserve capacity California has enjoyed in the past has shrunk to a dangerously low level. During peak load days in May and June, reserve margins were further reduced by unusually high levels of generation unit outages and a decrease in available supplies of out-of-state energy. This combination caused unusually high prices in both the PX and ISO markets and resulted in a high overall cost of wholesale power. If supply had increased to keep pace with even a modest share of the growth in demand over the past decade, there would have been sufficient reserve margins and a sufficient number of new supply entrants to allow competitive markets to moderate electricity prices this summer.

In markets where consumers have the ability to respond to price increases by reducing consumption, extraordinarily high prices during periods of true shortage of supply may be seen as legitimate "scarcity rents" because they reflect the willingness of consumers to pay for electricity. Moreover, where scarcity prices are set by consumer willingness-to-pay and there are no barriers to the entry of new suppliers, occasional high prices under scarcity conditions are important signals to new generators to enter the market. However, where consumer responsiveness and new entry are severely limited, as in today's electricity markets, the ability of suppliers to exercise market power under tight supply conditions cannot be limited by competitive market forces. In this situation effective mitigation of market power must be accomplished through rules, procedures and incentives designed into the structure of the markets themselves. The fundamental solution to mitigate this market power is to create ways for consumers to respond to increasing prices and accelerate entry to the market by new suppliers.

Based on our examination of the market, we believe that actions have to be taken to remedy the high costs experienced in May and June, and additional actions will be taken to further improve the performance of the market. All of the recommendations noted below are part of a comprehensive ISO Action Plan that outlines a number of short- and long-term initiatives which require ISO, UDC and state agency action. The ISO Board has already taken the immediate step to contain wholesale energy costs by lowering price caps to $250. This is only a first step. Additional actions are needed, and could include:

- **Accelerating the permitting and siting of generation and transmission projects.** One of the primary reasons for high prices has been the underlying tight supply conditions in the California market, which have been developing for more than a decade. Action should be taken to increase the amount of in-area generation through expedited siting and permitting of generation and transmission facilities that will be critical to ensuring that the supply of resources keeps up with needs created by accelerated load growth. We believe that expedited approval can and must be accomplished without compromising the need for adequate environmental impact review. In fact, we would expect enhanced environmental quality to result with the addition of cleaner, more efficient generation, and the re-powering of aging and inefficient resources with cleaner technologies.
- **Placing a priority on developing load responsive programs and removing barriers to load's ability to hedge.** These structural changes are critical to promoting competitive market outcomes by allowing load to protect itself from high prices. In the near-term, while the utility distribution companies (UDCs) are the retail electricity providers for the vast majority of California's load (and the exclusive default service providers), this involves expanding the ability of the UDCs to develop extensive load response programs and to enter forward hedging contracts in the wholesale markets. Forward financial contracts when combined with a retail rate freeze are an important measure for mitigating market power in all restructured spot markets.
- **Ensuring that the UDCs have adequate incentives to conduct their wholesale market activities in the most efficient manner possible to keep retail rates low.** At present the retail rate freeze and the rules for collecting CTC provide such incentives. However, as the recent experience of SDG&E's ratepayers indicates, once these mechanisms end there may be inadequate incentives for the UDCs to strive to minimize the costs of electricity for end users. Direct incentives such as the retail rate freeze on UDCs are critical mechanisms to mitigate market power in the wholesale electricity markets. This is because UDCs have the financial interest (dollar for dollar) to maintain low wholesale costs. This incentive causes them to work diligently using their knowledge of markets and remaining resources to keep wholesale prices low.
- **Promoting robust retail competition by removing key regulatory barriers.** In the longer–term, promoting competition among retailers will provide the incentive to keep electricity supply costs low. Among the current regulatory barriers are the lack of definition and structure for default service rates and the structure needed to provide the right incentives and opportunities for competitive provision and innovation in revenue cycle services (e.g. metering, meter reading, billing services, etc.).

Since the above recommendations will take time to implement, the ISO has imposed an immediate reduction of the price caps in its markets to $250/MWh as a short-term measure to contain wholesale prices. In addition, we are examining other changes to market procedures that might be implemented in the short-term to increase the incentives for generation owners to schedule their energy on a forward basis rather than transacting substantial percentages of total system needs in the real-time market.

In summary, the major cause of high wholesale prices this summer has been the absence of new investment in generation and transmission to meet the growth in demand over the past decade. The major cause of these high prices being passed on to retail customers in the SDG&E service area was the absence of means for final customers to respond to high wholesale prices, and the failure to provide any other market participant besides final customers with the financial incentive to maintain low wholesale prices. The Department of Market Analysis has identified the above measures, which include offering real choices to retail customers to protect themselves against high prices, as crucial to helping promote a more competitive wholesale electricity market in California.

EXECUTIVE SUMMARY

This report reviews the performance of California's energy and ancillary service markets from late May to mid July. It focuses on the key causes and market structure issues underlying the series of price spikes and high costs over this period. The body of the report examines in more detail the specific factors that contributed to price spikes in May and June. The major factors can be summarized in three areas:

- High Demand and Tight Supply in California and Regional Markets
- Market Design and Operational Features that Contributed to High Cost
- Market Power and Scarcity Rent

I. High Demand and Tight Supply in California and Regional Markets

- **High Peak Demand Growth.** A major factor underlying the price spikes in May and June was high levels of demand. This was due to robust economic growth throughout the West over the last few years, coupled with unseasonably high temperatures, which reached 1-in-10 year highs for the months of May and June in many parts of the state. Average daily peak loads grew by 13% in May and 15% in June compared to these same months of 1999.
- **Units on Scheduled Maintenance and Forced Outages.** Because May and June are typically marked by relatively moderate loads, high hydro run-off, and some of the lowest energy prices of the year, this is traditionally a period when maintenance is done to prepare generation units for the peak summer months. In addition, the May and June price spikes coincided with an unusually high rate of forced outages within the ISO system, as well as in other control areas. During the May 22 price spike, about 22% of the state's nearly 17,000 MW of thermal generation recently divested by the state's IOUs to Non-utility Generation Owners (NGOs) was unavailable due to scheduled maintenance and forced outages. During the June price spikes, an average of about 10% of this generation capacity was unavailable due to scheduled maintenance and forced outages. Although these current outage rates may seem high compared to long-term historical outage rates, we expect that maintenance and forced outage rates may increase from historical levels due to the increasing age of the existing stock of generation plants.[1] These unit outages – combined with a variety of transmission system outages – also played a key role in local area shortages and reliability problems. These issues are the subject of reports and information provided by other departments of the ISO.
- **Higher Gas Prices.** There has been a significant increase in natural gas prices with an almost doubling from $2.50/MMBTU in June of 1999 to $5.00/MMBTU in June of 2000. The recent increase in gas prices is the most easily quantified factor underlying the high costs of electricity in June. About 20% of the increase in overall electricity costs in June 2000 compared to Summer 1999 can be attributed to the doubling of natural gas prices over the last 12 months.[2] As loads moderated during the first two weeks of July 2000, electricity prices returned to 1999 levels when adjusted for the increase in natural gas prices over the last 12 months.

[1] Over 60% of California's gas and oil-fired generation capacity is over thirty years old. As power plants age, they require more maintenance and are more prone to outages. In addition, current demand and supply conditions are causing many older plants to be operated and "cycled" on and off with increasing frequency, which tends to increase the frequency of maintenance and forced outages.

[2] See Table 2 of report for details of this analysis.

Lack of New Investment in Generation and Transmission. Despite robust economic growth, there has been little new investment in generation and transmission in California during the past 15 years.

Tight regional supply and reduced imports. Tight regional demand/supply conditions affect California's deregulated energy market in several ways. First, because California requires significant imports of electricity to meet demand during peak demand periods, tight regional supply conditions reduce the supply (and increase the cost) of imports available to meet demand. In addition, tight regional supply conditions – combined with the development of regional market hubs in which merchant generators may sell electricity – also increase the opportunity cost (and decreases the supply) of power within California available to meet demand. Finally, tight demand and supply conditions on a regional level also create the potential for the exercise of market power on a regional level by entities controlling available excess supply (i.e. supply beyond what an entity may need to meet its own load or pre-existing contract obligations). Diagnosing the amount of market power that may exist and be exercised on a regional level is extremely difficult, and will be the subject of further investigation by the ISO in conjunction with other entities.

. Market Design and Operational Features that Contributed to High Cost

ı addition to the tight supply and demand conditions, several fundamental features of California's market tructure and design play a key role in explaining recent market performance and price spikes. Some of ıese are likely to continue facing the ISO in the coming months.

- **Lack of Demand-side Response to Prices.** Critical to the working of all deregulated markets is the capability of loads to respond to prices and hedge against high prices. There are many regulatory barriers to bringing about price-responsive demand and forward market hedging within the current California market structure.
- **Under-scheduling of Loads and Generation.** Recent aggregated bid information released by the PX shows that supply being offered in the PX market is lower in quantity and higher in price than the supply offered under comparable load conditions last year.[3] Decreased supply in the PX is attributed to two key factors. First, a significant amount of thermal capacity divested to merchant generators is being scheduled through bilateral contracts or through regional block forward and spot markets. Of capacity scheduled through these bilateral or forward market contracts, a significantly greater amount appears to have been purchased for out-of-state markets. The result has been an increase in gross exports and a decrease in overall net imports into the California market. In addition, high real-time and replacement reserve purchase prices and quantities have created a significant opportunity cost that may have led suppliers to withhold or bid higher prices in the PX Day Ahead market.

  Price spikes in the ISO's real-time market during May and June occurred primarily during hours when the ISO needed to increment significant amounts of generation in real time in order to meet demand due to under-scheduling of loads and generation in the Day Ahead and Hour Ahead markets. Most under-scheduling can be attributed to strategic bidding of demand and supply resources in the Day Ahead and Hour Ahead markets. Until recently, large buyers appear to have successfully limited their exposure to overall wholesale price spikes by their ability to shift demand into the real-time market. However, the ability of large buyers to "defend" against potential exercise of market power and lower costs during periods where there is a true shortage of supply has been limited in recent months due to

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' See presentation on *Price Behavior in Cal-PX Markets: May-June 2000*, prepared by PX compliance Unit for the Energy Oversight Board, June 29, 2000, available in archives on PX website (calpx.com) suppliers offering less supply at higher prices in the Day Ahead market and the ISO's policy to charge replacement reserve to under-scheduled load and over-scheduled generation.

Replacement Reserve Procurement Policy. One of the key adjustments the ISO made following the May 22 events was to implement an operational practice of *defending* against significant under-scheduling of loads (and avoiding potential *out-of-market* purchases). The ISO would purchase large volumes of replacement reserve capacity to narrow the gap between scheduled and forecasted loads. In some hours, as much as 25% of system needs were met in the real-time market. This significant level of under-scheduling is largely attributable to the different market incentives faced by buyers and sellers. Large buyers try to "defend" against higher prices in the PX Day Ahead Market by shifting some of their demand to the real-time market and suppliers have offered less supply at higher prices in the Day Ahead market because of opportunities to earn higher replacement reserve payments and real time energy prices. An important objective from a reliability perspective is to limit the amount of transactions in real time. Creating stronger incentives for load and suppliers to bid and schedule in the forward markets will help reliability and promote more competitive markets.

Reliance on Supplemental Energy from Other Control Areas. A key issue encountered during the May and June price spikes involves the difficulty of relying on supplemental energy bids (representing "unreserved" capacity) from other control areas to meet demand in real time during periods of tight regional supply/demand conditions. During extremely tight supply conditions, supplemental energy bids from neighboring control areas have decreased significantly. This occurs precisely when the ISO projects a shortfall of operating reserves and faces the need to initiate *out-of-market* purchases from suppliers in neighboring control areas in order to ensure sufficient supplies for projected peak demand in the afternoon hours.

When purchasing energy *out-of-market*, the ISO has typically purchased multi-hour blocks of energy at prices at or near the $750 price cap. *Out-of-market* purchases made during May and June included some multi-hour blocks of energy purchased at $750/MW, which spanned hours during which the *ex post* real-time imbalance price (the price paid to suppliers subsequently dispatched through the ISO's hourly real-time imbalance market) was below $750. From the ISO's perspective, this experience highlights the difficulty of relying on supplemental energy supplies to ensure system reliability: Suppliers *negotiating out-of-market* transactions for blocks of energy at prices that may be higher than the ex-post price seriously undermine the operations of the ISO energy and ancillary services markets. If in-state generators know that a better deal can be had from out-of-market purchases than from participating in the ISO's market, then we would expect them to export their power to out-of-state control areas and reduce their participation in the ISO's markets, thereby exacerbating the need for *out-of-market* purchases under tight supply/demand conditions.

From the perspective of the out-of-control-area suppliers, sales of blocks of energy during very tight supply and demand conditions provide a number of advantages. These include the ability to compare revenues from sales to the ISO against potential sales in other regional spot markets and bilateral transactions that are not conducted based on real-time hourly markets with *ex post* market prices. However, from the perspective of suppliers within the ISO control area, any out-of-market purchases of energy at prices higher than the *ex post* price unfairly discriminate against suppliers participating in the ISO's hourly real-time market.

The ISO's reliance on out-of-market purchases also creates operational concerns, due to the "manual", case-by-case nature in which out-of-market purchases may need to be made. Relying on out-of-market mechanisms to meet a large volume of demand in real time involves significant inefficiencies (as well as potential reliability concerns) in the event that either "too much" or "too little" energy is purchased out-of-market to meet real time demand.

III. Market Power and Scarcity Rent

In restructuring the California power market, divestiture of generation resources was an important means of mitigating market power. None of the current non-utility generation owners have more than a 9% of share of total generation capacity in California, and previous analysis[4] shows that the California wholesale energy market is competitive except for peak demand hours. Under the tight demand and supply conditions experienced in May and June of 2000, however, the incidence of high prices clearly highlighted that the remaining market power can have an extremely costly impact.

Our analysis of the events of May and June and the behavior of market participants in causing price spikes distinguishes between the exploitation of *market power* and *scarcity rents* which are derived from true willingness of consumers to buy under conditions of scarcity or shortage of supply. The classical economic definition of a workably competitive market is one in which a large number of firms compete to produce the same product and no firm is able to raise prices significantly above system marginal costs for a sustained time period. A workably competitive market produces market clearing prices which are reasonably close to system marginal cost, i.e. the highest cost unit necessary to serve the load. Market power exists if firms have the ability to raise prices significantly above system marginal cost for a sustained period of time unimpeded by competition from other suppliers, other substitute products, or demand response.

Not all incidences of price exceeding system marginal cost are evidence of market power, because scarcity rents are legitimate during hours of shortage. Scarcity rents are appropriate when the level of electricity demand is such that there is little, if any, unused capacity available throughout the system and consumers have the ability to reduce their purchases as the price rises. In these instances, prices in the market should be set by the willingness of consumers to forego purchases of electricity, rather than by the bids of generators. These market conditions indicate genuine scarcity of generating capacity, because all available capacity is used and no additional capacity exists to serve any incremental increase in demand.

Due to the extremely limited degree of demand elasticity that currently exists in California's newly deregulated energy market, the ISO's real-time price cap has had to serve as a proxy for consumers' willingness-to-pay during periods of true scarcity, as well as the limit on generator market power during periods of high demand. However, while price caps can serve as a proxy for consumers' willingness-to-pay during periods of true scarcity and limit market power during periods of high demand, price caps do not allow price signals to actually be sent to consumers, many of which would reduce demand if exposed to extremely high prices. Thus, price caps represent a very imperfect proxy for actual demand elasticity.

Shortage can be defined for two geographic areas: a California ISO control area shortage and a greater Western regional shortage. A California ISO control area shortage is when net demand for capacity[5] (total demand for capacity minus actual imported energy and reserve) is greater than the available capacity from

[4] Frank Wolak, Borenstein and Bushnell, "Diagnosing Market Power in California's Restructured Electricity Market,", April, 2000, available from http://www.stanford.edu/~wolak.

[5] Demand for capacity is the demand for energy plus losses and requirements for operating reserves and upward regulation service (measured in MW for any particular hour).

generation resources inside the ISO control area. This type of shortage is influenced by the amount of available imports. The regional shortage definition extends the scope to the surrounding control areas to cover the entire WSCC region, and compares the entire regional demand for capacity with available capacity in the region.

Our preliminary analysis shows there were shortages in the California ISO control area for a number of hours, when available capacity was not sufficient to meet the net demand for capacity. There were other high price hours when we cannot identify any apparent shortage and the high prices can clearly be attributed to market power. The presence of market power can be verified by bid prices significantly over the variable costs of many suppliers in the ISO's markets. The highest variable cost of in-state generators is below $100/MWh, while many suppliers routinely bid a significant part of their capacity at $750 (the price cap level). With supply limited and high demand, these bids are guaranteed to be selected to meet the demand during high load periods.

The observed market power was the combined effect of the bidding activity of in-state and out-of-state generation resources. The available data and tools do not allow detailed analysis of the market power of out-of-state generation owners. The ISO, however, is not aware of any acute regional shortages in most of the high price hours. The high prices bid by out-of-state suppliers as well as the high prices quoted to ISO's out-of-market calls are indications of the market power of out-of-state suppliers.

The divestiture of generation resources by IOUs has resulted in a market share of approximately 9% for a few of the large non-utility generation companies. These companies are net sellers who can profit from price spikes. While for most hours the ISO markets are sufficiently competitive, at high load conditions, a capacity share of 9% or less can give market suppliers a pivotal position. This implies that, at high load conditions, even suppliers with less than a 9% market share can have significant market power. When net demand for capacity in the ISO control area is more than 91% of available capacity, all suppliers can easily bid high prices, and know their bids will be accepted and set the market clearing price. Thus, prices have hit the price cap during many hours even when there is not a shortage on the system.

Fundamental Corrective Measures

The following fundamental could be implemented to facilitate the development of workably competitive wholesale energy markets:

- **Expedite Generation and Transmission Investment.** Although it is clearly a long-term market power mitigation measure, the California Energy Commission and other state agencies should expedite the siting and approval process for all new plants under consideration. The fact that siting power plants in California takes considerable longer than other surrounding states hinders the ability of new entry to mitigate market power. These state agencies should also allow the ISO to take a pro-active role in the determination of the need for new transmission investment. Given that transmission constraints enhance the ability of generators to exercise their market power, transmission upgrades have the potential to significantly increase the efficiency of the ISO's energy and ancillary services markets. Consistent with siting and environmental review, any transmission upgrade that reduces total energy and ancillary services costs on an annual basis by more than the annual cost of the transmission upgrade should be undertaken as soon as possible.

- **Clarification of Retail Sector Structure.** An important contributing factor to the price spikes in the ISO's energy and ancillary services market is the lack of clarity regarding the structure of the retail sector. Under the current market rules, in any UDC territory not subject to a retail rate freeze, there are no market participants, besides individual consumers, with an incentive to lower wholesale prices. Because hourly wholesale prices must be passed through in retail rates, higher wholesale prices simply increase the cost of doing business to all retail suppliers. Given that all the parameters necessary for robust retail competition have not yet been determined by the California Public Utilities Commission (CPUC), there is also little reason to believe that retail competition will provide the strong incentives to lower wholesale prices.
- **Remove Barriers to Demand-Response Programs and Hedging.** Crucial to the success of any initiatives in the retail sector is the removal of all regulatory barriers to forward contracting by all load-serving entities, including the UDCs. Had the UDCs had the ability to fully contract their peak net demand position in the forward energy markets, it is unlikely that nearly as many price spikes would have occurred during May and June, and those that did would have been significantly less costly to final load. By restricting forward purchases by the UDCs to the PX block forward market, the CPUC is restricting the ability of these load-serving entities to mitigate market power in a least-cost manner. A second crucial feature to the success of either of the above two options to mitigating market power is to remove all regulatory barriers to price-responsive final demand. Either of the above two solutions must allow all UDCs complete freedom in configuring price-responsive demand programs. Subject to the retail rate freeze in the first option or robust retail competition under the second option, all load serving entities should be able to offer pricing contracts which support a price-responsive hourly demand.
- **Market Power Mitigation Options Should Include Maintaining Short-term Purchase Price Caps and Instituting Incentives for Forward Scheduling.** A short-term option for the summer of 2000 was to implement lower purchase price caps on the ISO's energy and ancillary services markets. Because of inadequate forward market purchases by the UDCs for the summer of 2000, price caps were one of the few short-term options for market power mitigation available to the ISO. However, there are uncertain reliability costs associated with implementing lower caps, with the ISO having to make out-of-market purchases at whatever price is necessary to maintain system reliability. This also creates a tremendous incentive for in-state resources to export outside of the ISO control area during high demand periods in order to sell this energy back into California through out-of-market transactions. Reliability concerns also dictate that the ISO have options to encourage all available capacity to be either submitted in a day-ahead energy schedule or bid into the ISO's day-ahead ancillary services market. Some potential options for reducing underscheduling include: charging bids or schedules not submitted in the Day Ahead (bilateral, PX, or ancillary service) markets, additional fees for transactions in real-time markets, establishing an availability standard, and penalizing physical withholding and/or specifying a requirement for a certain portion of loads to be forward scheduled. However, each of these options should be carefully examined to assess the potential positive and negative market impacts.

The following report provides a more detailed discussion of these events and issues summarized above. The report is organized as follows:

- Section II provides an overview and chronology of market performance and events from late May to mid-July 2000.
- Section III provides an estimate of the total market costs during this period, examines how these costs impact different market participants over the short-term, and summarizes these recent costs in a longer-term perspective of market energy costs before and since deregulation.
- Section IV examines the issue of underscheduling of load and generation, and potential options that have been proposed or discussed for reducing the operational problems stemming from underscheduling.
- Section V reviews the role that purchasing large quantities of replacement reserve may play in ensuring reliability, as well as total energy costs.
- Section VI examines the relationship between the California's energy markets and other regional markets, and how this relationship may impact policy and market design decisions.
- Section VII examines the issue of scarcity vs. market power in the context of the recent price spikes, and other related issues discussed in this report.

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II. Overview of Market Events and Performance

This section provides an overview of demand and supply conditions during the May and June price spikes. Subsequent sections provide a more detailed discussion of underlying causes and impacts of the price spikes. The price spikes occurring during May and June were triggered in large part by unseasonably hot weather, which — coupled with the significant economic growth that has occurred over the last two years – created record high electric loads for these months. Unlike most heat waves experienced during the ISO's first two years of operation, the May and June heat waves coincided with high demand (and unusual amount of forced and scheduled outages) on a regional level. As a result of these factors, the number of hours when peak loads hit critical levels in terms of both market power and potential scarcity of regional supply grew dramatically.

Chronological Summary of Market Performance

May Price Spikes

- Price spikes in May began in the real time market on May 21, when actual peak loads exceeded forecasted by nearly 3,000 MW, or about 9% (see Figure 1). On May 21, prices approached the ISO's real time price cap several hours, hitting \$632 and \$732 during hours 15-16, while prices in the PX Day Ahead market (clearing on May 20) remained below \$52 during all hours (see Figure 3).
- Price spikes at the \$750 continued in the real time market on May 22, when loads peaked at 39,532 MW, and PX prices rose to over \$200 during the early evening hours. On May 22, the ISO purchased over 9,100 MWh of energy out-of-market for hours ending 12 – 21 (or an average of over 1,000 MW per hour over this 9 hour period) from suppliers outside the ISO's control area in order to ensure system reliability in the face of forecasted loads of over 40,000 MW. The price for most energy purchased out-of-market on May 22 was \$750, with average price of \$723/MWh, compared to a weighted average ex post price of about \$523. Additional information on out-of-market purchases in May and June is provided in Section II of this report.
- Prices in the PX rose to over \$400 for operating day May 23, while prices in the real time market dropped. This trend may be attributable in large part to the fact that actual loads on May 23 fell well below the level of loads being forecasted at the time of the Day Ahead market (run May 22 for operating day May 23), as shown in Figure 2.
- Prices in the PX remained over \$200 during the super peak hours of May 24, while prices in the real time market dropped to under \$50 during these hours. This trend may again be attributable in large part to the fact that actual loads on May 24 fell well below the level of loads being forecasted at the time of the PX Day Ahead market the previous day (see Figure 2).
- During the May 21-24 period, PX prices spiked over \$100/MW at loads of over 30,000 MW, and spiked over \$200/MW as loads exceeded 35,000 MW. As discussed later in this report, price spikes during June occurred primarily during hours when loads exceeded 35,000 MW, and neared the \$750 level as loads exceeded 40,000 MW. This difference reflects the difference in the amount of capacity unavailable during these two periods. During the May 22-25 period, about 6,600 MW in ISO control area was unavailable due to outages, while the amount of capacity out during the June price spikes generally ranged from 2,000 to about 3,000 MW.

Figure 1. May Load Conditions (1999 vs. 2000)

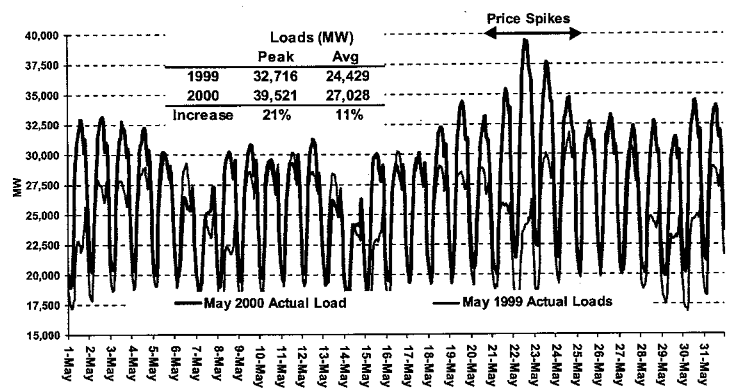


Figure 2. Loads and Schedules During May Price Spikes

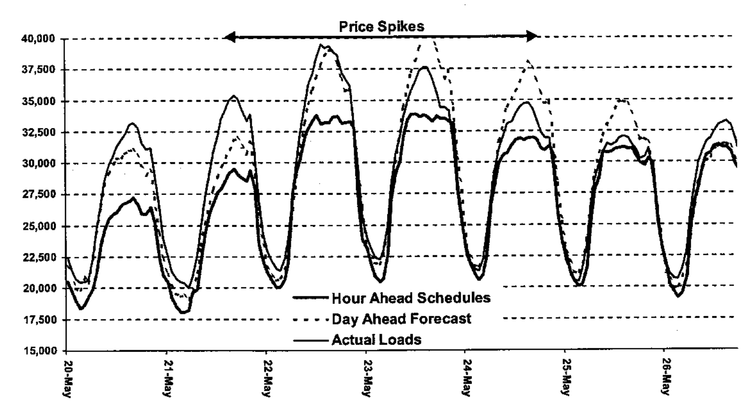
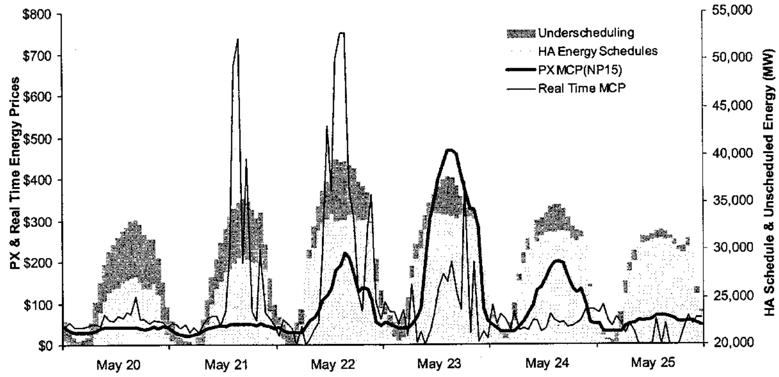


Figure 3. PX Day Ahead and Real Time Imbalance Prices (May 20-25)



June Price Spikes

- In June, average daily peak loads grew by 15% in May, with peak loads growing by 6% compared to May 1999 (see Figure 1).
- Loads exceeded 40,000 MW during 51 hours in June, compared to a total of only 56 hours of loads over 40,000 experienced during the entire three month period of June-August, 1999. Most of the hours when loads exceeded 40,000 fell during two major heat waves: June 13 –16, and June 26-30.
- Severe price spikes in the PX Day Ahead energy and ISO's ancillary service and real time markets occurred during two major heat waves: June 14 –16, and June 26-30. As discussed in the following section of this report, over 70% of up to $3.6 billion in market costs incurred during the month of June were incurred during the peak hours of these eight days.
- During the June 14-16 period, prices in the PX Day Ahead market averaged $387 during the peak hours (7–22), and exceeded the $600 level for 5 hours during this 3-day period.
- Despite peak daily loads over 40,000 MW on June 21-22, PX Day Ahead prices did not rise above $271. Real time prices exceeded $700 during 4 hours during this period, hitting the $750 cap during two hours on June 21.
- During the June 26-30 period, PX Day Ahead prices averaged $381 during peak hours (7 to 22), and reached or exceeded the $749 level during seven-hour block on both June 28 and 29. On June 28, constrained prices in NP15 reached an all-time high of $1099 for five hours.

Figure 4. June Load Conditions (1999 vs. 2000)

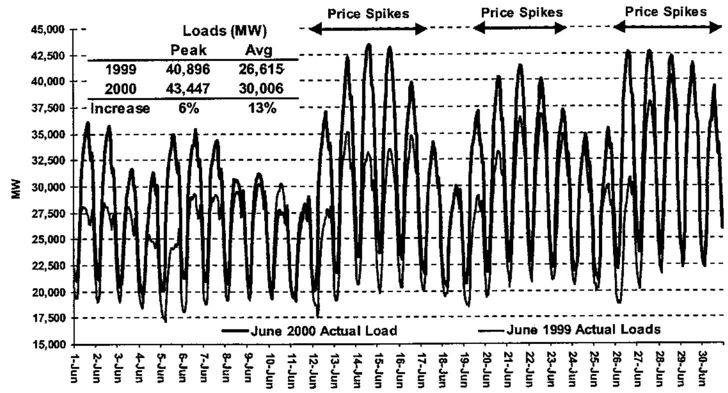


Figure 5. Loads and Schedules During June Price Spikes

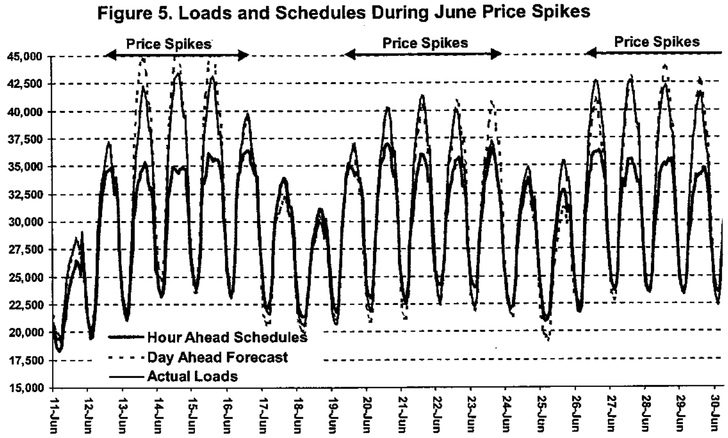
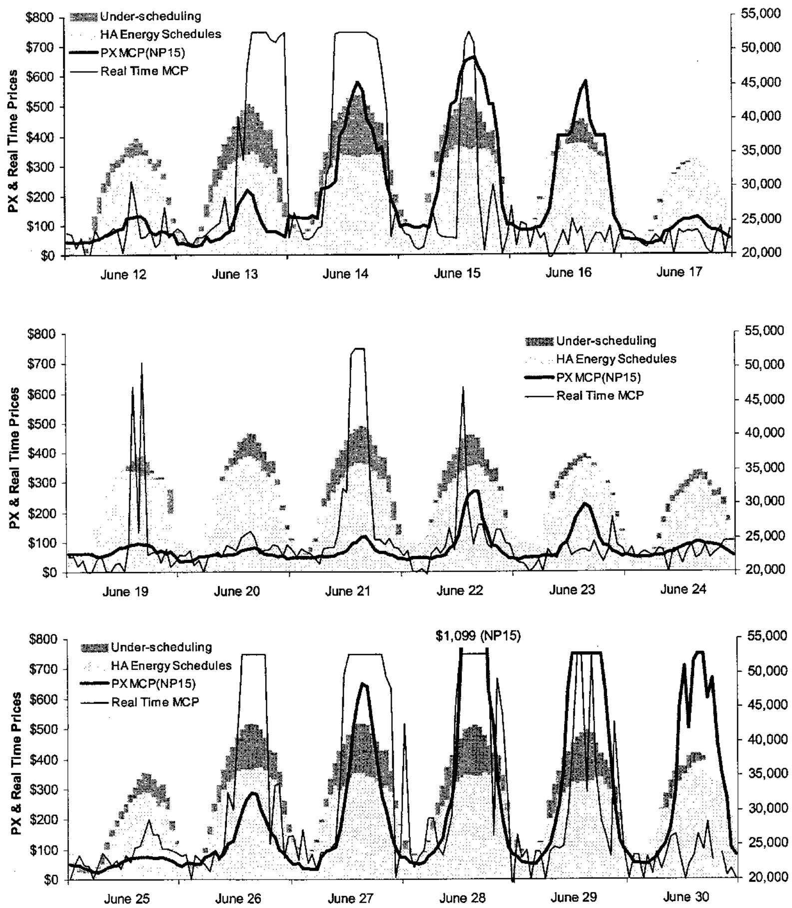


Figure 6. PX and Real Time Energy Prices (June Heat Waves)



- The higher PX prices during that June 26-30 heat wave appear to be due, at least in part, to an adjustment of demand bidding in the PX reflecting a willingness to pay significantly higher prices in the Day Ahead market. This adjustment may be attributable to the higher cost of demand met in the real time market due to the combination of higher real time prices, plus significant deviation replacement reserve charges. These issues are discussed in other sections of this report.
- Real time prices hit the $750 price cap at total of 24 hours over the four-day period from June 26-20, before dropping on June 30.

III. Total Market Costs

This section provides an estimate of the financial magnitude of the May and June price spikes based on the amount of load served and prices in different energy and ancillary service markets. For this analysis, we estimated total market costs as follows:

- Costs of scheduled energy (which includes loads and generation scheduled in the Day Ahead PX as well as bilateral markets or "self-scheduled" loads/generation) are estimated based on the total Hour Ahead schedules valued at the market clearing prices in the PX Day Ahead market.[6]
- Costs of energy met in the real time market are estimated based on the difference between actual loads and scheduled loads, multiplied by the real time prices.[7]
- Costs of Replacement Reserve, which accounted for a very high portion of ancillary service costs in June, were assumed to be allocated entirely based on unscheduled loads met in the real time market.[8]
- Costs of all other ancillary services were assumed to be allocated based on actual loads.

Figure 7 summarizes total daily costs for each of these four categories from the period May 18 through July 5. Figure 8 shows a more detailed breakdown of costs in the ISO markets (real time energy, replacement reserve, and other ancillary services) for this same time period. As shown in Figures 7– 9:

- Over 73% of total market costs during the month of June were incurred during the peak hours of the eight days from June 13 –16 and June 26-30.
- The portion of ISO market costs incurred during the heat waves of June 13-16 and June 26-30 was even greater, with over 87% of total real time energy and ancillary service market costs incurred during these two heat waves.

Figure 9 and Table 1 provide a summary and additional discussion of total monthly costs by each category, including a breakdown of scheduled energy costs based on the approximate portion load actually scheduled in the PX versus other schedule co-ordinators. As shown in Figure 9 and Table 1, California's energy and ancillary service markets represented a $3.6 billion market in June, with the ISO real time and ancillary service markets accounting for about $765 million, or approximately 21% of total market costs during June.

Table 2 shows a calculation of the extent to which price increases in June may be attributed to higher gas prices relative to the summer months of 1999 (June to August). As shown in Table 2, at least 20% of the increase in total cost per MWh of load served in June 2000 relative to the summer months of 1999 may be directly attributable to the increase in gas prices over the last year. It should be noted that this example is based on what may be a conservative estimate of the average heat rate of the marginal unit needed to meet demand, since during many of the hours when prices were highest in the ISO system, resources with much higher heat rates were needed to meet demand. For instance, based on an average heat of 16,000

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[6] In effect, this approach values all loads and generation that is scheduled through final Hour Ahead schedules at the PX price. In practice, the actual price of a portion of this generation may depend on pre-agreed contract prices and other bilateral arrangements.The average of the zonal prices in SP15 and NP15 is used to approximate the amount of load met at each zonal price.

[7] See Footnote 5.

[8] In practice, a relatively small portion of Replacement Reserve that was not procured as Deviation Replacement Reserve in June may in fact be billed based on total load, rather than unscheduled deviations. We did not attempt to exactly replicate the actual allocation of these costs in the ISO settlement process.

MMBTU/MWh the price increase in June due to higher gas prices may reach $35, or about 27% of the price increase relative to summer 1999.

Figure 7. Total Daily Energy and Ancillary Service Market Costs (May and June Heat Waves)

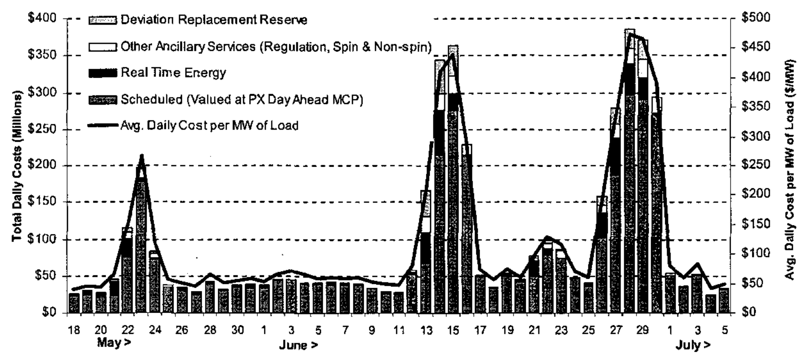


Figure 8. Total Daily ISO Real time and Ancillary Service Market Costs (May and June Heat Waves)

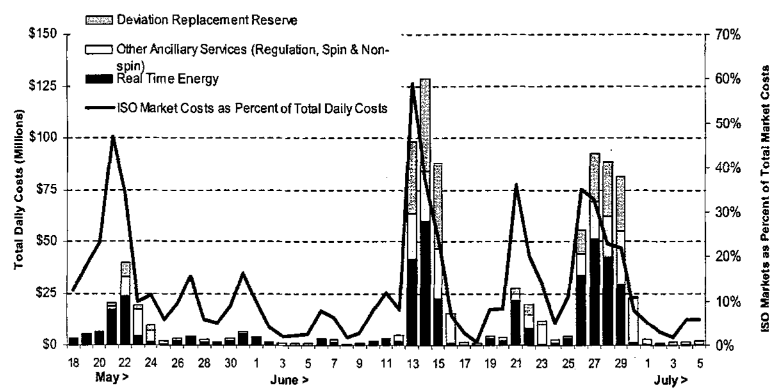
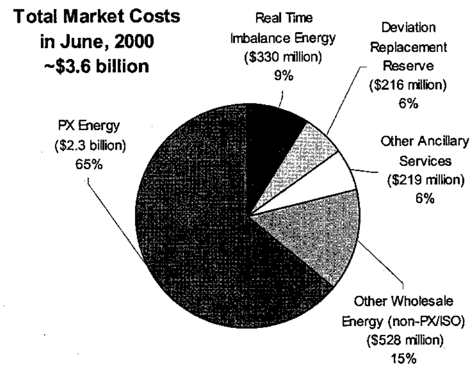


Figure 9. Total California Energy Market Costs, June 2000



California's energy and ancillary services markets represented a total market value of up to $3.6 billion in June 2000. In the figure above, total market costs are estimated based on total loads and schedules in the ISO system, valued at prices in the major PX and ISO energy and ancillary services markets. Additional details of how overall costs were estimated based on overall system loads, hour ahead energy schedules, and market clearing prices and quantities in the PX and ISO markets are provided in the text of this report and in Table 1. To the extent that some energy was "pre-purchased" by buyers through bilateral transactions and forward market hedging (such as the PX's block forward markets), actual costs paid by buyers would be lower than the $3.6 billion "value" of California's energy and ancillary service markets at market clearing prices.

The PX Day Ahead market accounts for the largest portion of California's energy market, representing a total market of $2.3 billion (or 65% of total market costs) in June. When valued at PX Day Ahead price, other energy scheduled in the Day Ahead and Hour Ahead markets (which includes bilateral transactions and municipal loads) represents a total market value of over $500 million in June.

The ISO real time market accounted for about $330 million in costs, or about 9% of the total wholesale market in June. Another $216 million (or about 6% of total market costs) was incurred due to replacement reserve capacity purchased by the ISO to ensure reliability in the face of significant underscheduling of loads and generation in the forward markets during many peak hours. The cost of replacement reserve purchased due to underscheduling is allocated based on uninstructed deviations in real time, which includes loads that were not scheduled in the Day Ahead or Hour Ahead market. Other ancillary services, which are billed based on metered demand, accounted for about another $219 million (or about 6% of total market costs).

Table 1. Total Market Costs per MWh of Load, June 2000

	Total Costs (Millions)	Total MWh	Avg $/MWh
PX Day Ahead [1]	$2,301	17,219,831	$134
Other [2]	$528	3,518,567	$150
Scheduled Energy[3]	$2,830	20,738,398	$136
Real Time Imbalance Market[4]	$330	867,447	$381
Replacement Reserve[5]	$217	867,447	$250
Real Time Energy (Effective Price)[6]	$547	867,447	$631
Total Energy (Weighted	$3,377	21,605,845	$156
Other Ancillary Services[7]	$219	21,605,845	$10
Total Average Price	$3,596	21,605,845	$166

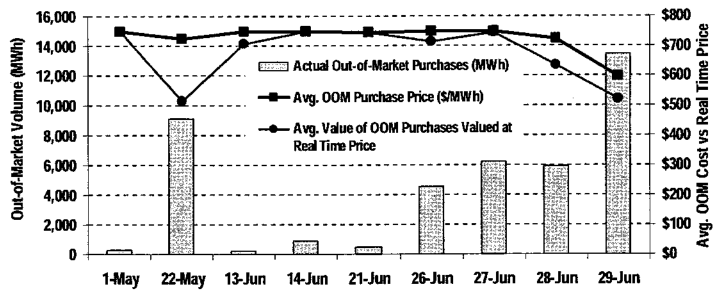
[1] PX MCQ x Avg
[2] (Final HA Scheduled - PX UMCQ) x Avg PX
[3] Final HA Scheduled x Avg PX
[4] (Actual Load - Final HA Schedule) x Avg PX
[5] Assumes Total Replacement Reserve Cost
to Deviations between Actual and Hour Ahead
[6] Effective Price of Unscheduled Energy (Real Time Price + Replacement Rese
[7] Regulation, Spin and Non-spin (MCP x MCQ, Day Ahead + Hour

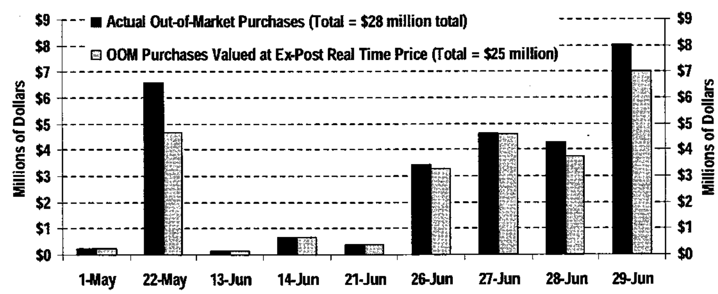
Table 2. Potential Increase Due to Gas Price

	Summer 1999	June 2000	Difference
Average Daily Gas Price [1]	$2.56	$4.73	$2.17
Average Marginal Heat Rate [2]	12,000	12,000	
Marginal Fuel Cost	$31	$57	$26
Average Total Cost [3]	$36	$166	$130
Increase in total cost per MWh of load due to Gas Price [4]			20%

[1] Average daily spot market price in Northern California
[2] Assumption of average heat rate of marginal unit needed to meet demand.
[3] Includes energy and ancillary service costs, as shown Table 1.
[4] $26 increase due to gas price ÷ $130 increase in total costs oer MWh of load served. Under the assumption of an average peak hour heat rate of 16,000 MMBtu, the same calculations show that the price increase in June due to gas prices may be as high as $35, or about 27% of the price increase relative to summer 1999 months.

Figure 10. Out-of-Market Purchases





The charts above show out-of-market purchases by the ISO during the months of May and June. Over this period, about 60% of the energy purchased out-of-market by the ISO was at a pre-agreed price equal to the $750 price cap in effect during May and June. About 10% of out-of-market energy was procured at a price of $750 during hours when the real time price hit the $750 price cap through agreements under which suppliers were paid the ex post real time price. The remaining portion of real time energy procured out-of-market was at bid or pre-agreed prices less than $750. Overall, the average price paid for energy out-of-market was $690, compared to a weighted average ex post real time price of over $600 during hours when this energy was procured. The difference in average price paid for out-of-market energy and weighted average value of this energy at the real time price is due primarily to the purchase of some energy out-of-market at the $750 level (made during the morning of several operating days) for hours when the real time ex post price ultimately fell below $750.

As shown in Figure 10, which provides a summary and discussion of out-of-market purchases by the ISO during May and June, out-of-market purchases accounted for a relatively small portion of total real time energy costs over these months. During May and June, out-of-market purchases of energy to meet demand in the real time market totaled about $28 million, with a value of $25 million based on the corresponding hourly ex post real time price (see Figure 10 for more detailed discussion).

Figures 11 and 12 examine the issue of how the $3.6 billion in total market costs may ultimately affect different market participants and consumers. As shown in Figure 11:

- Publicly available data on the total volume of net sales in the PX block forward market for NP15 show that PG&E may have hedged up to about 1,100 MW in the block forward market in June and about 1,800 MW in the other summer months out of a limit of about 3,000 MW allowed by the CPUC.
- The net volume of sales in the SP15 block forward market indicates that SCE may have hedged about 1,750 MW of its 2,200 MW limit in June, and about 3,000 to 3,500 MW of its 5,200 MW limit for the months of July to September.

Figure 12 and the accompanying discussion provide information concerning how total market costs incurred in June could ultimately impact different customers, IOU shareholders, and other market participants. It should be noted that actual impact that price increases depends a variety of factors beyond the scope of this analysis, and that other entities in California are better able to assess these impacts. However, information in Figure 12 is provided in this report to assist other entities in making such assessments, and to provide a preliminary indication of the ultimate impact of the June price spikes in terms of these different groups. As shown in Figure 12:

- At least 34% of costs incurred by the state's major IOU's (PG&E and SCE) are paid, in effect, to themselves as a result of generation owned by these utilities.
- We estimate that another 6% of costs in June were hedged through 2,850 MW sold in the PX block forward markets. For this example, we have assumed that energy purchased in the NP15 and SP15 block forward markets was purchased by PG&E and SCE, respectively. The portion of amount of total market costs (previously shown in Figure 10) that was hedged by these purchases (shown in Figure 12) was estimated by multiplying the amount of energy purchased in the PX block forward market by the average value of this energy based on average PX prices during the 6 x 16 hour period covered in the block forward market ($172 MWh).
- Remaining costs for the state's two major IOUs are partially covered in the frozen retail rates currently charged to PG&E and SCE customers. For instance, while costs for unhedged energy procured by IOUs in June may average about 16.6 cents/kWh, retail rates for the major IOUs include approximately 6 cents/kWh for recovery of energy charges and CTC recovery. Consequently, to provide an indication of the portion of energy costs increases that may impact shareholders of the major IOUs, Figure 12 further reduces the total potential cost exposure of the major IOUs by the amount of these costs that are covered in current retail rates.[9]
- Due to the rate freeze, costs not hedged or recovered through frozen rates may ultimately have the effect of delaying repayment of the Competitive Transition Charge (CTC), and/or the ultimate level of CTC recovered by IOU's. As noted above, we estimated the portion of costs that may impact the CTC

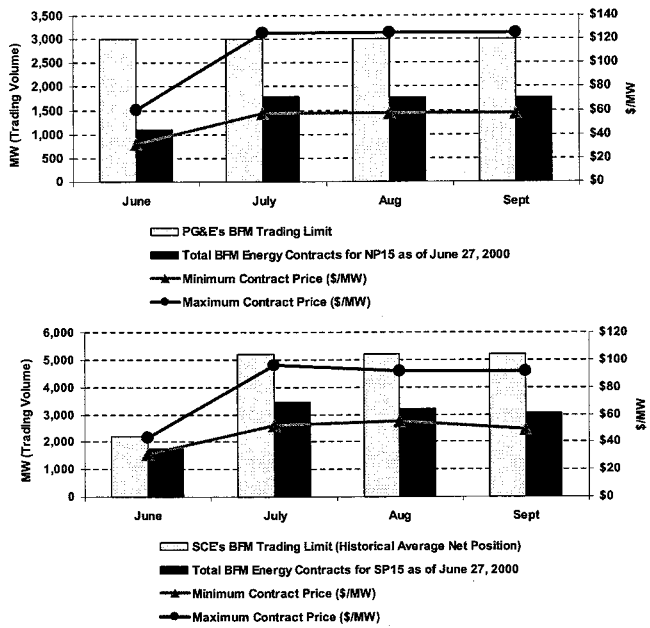
[9] Specifically, Figure 12 assumes that while the cost of unhedged energy procured by the state's major IUO in June averaged about 16.6 cents/kWh, retail rates for the major IOUs include approximately 6 cents/kWh for recover of energy charges and CTC recovery.

recovery based on the total market energy costs of PG&E and SCE not covered by either (1) estimated revenues from self-owned generation, (2) hedged by block market purchases, or (3) recovered in the frozen retail rates currently charged to PG&E and SCE customers. Results of this analysis are depicted in Figure 12 as "Potential Negative CTC Recovery".

> Direct access customers, ESP and municipals are estimated to account for about 17% of total loads and costs. Many of these loads are likely to be covered by bilateral contracts, so that cost impacts between customers and Energy Service Providers (ESPs) depend on the nature of each contract and the extent to which supplies for these customers were hedged through forward contracts.

> SDG&E, which has repaid its CTC and is no longer under a rate freeze, is estimated to account for about 6% of total market costs in June.

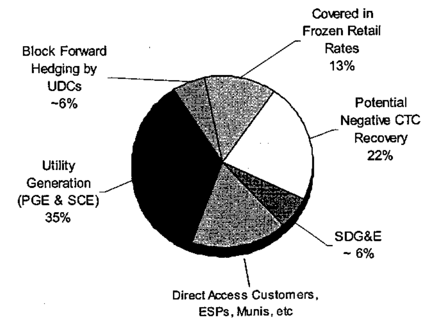
Figure 11. Forward Market Hedging in the PX Block Forward Market



The ability of California's two major utilities (PG&E and SCE) to hedge against high prices in the PX Day Ahead by pre-purchasing energy in other forward markets is currently limited by CPUC regulations in terms of both the quantity they may hedge, as well as the markets in which they may participate. UDCs are required to make all forward market purchases through the PX's block forward market. In addition, PG&E and SCE were limited to block forward market purchases of about 3,000 MW and 5,000 MW, respectively, during the summer 2000 months. Block Forward market hedging limits were based on levels requested by utilities, and were designed to allow each utility to hedge it's average minimum load during the peak summer months.

As shown in the charts above, publicly available data on the total volume of net sales in the PX block forward market for NP15 show that PG&E may have hedged up to about 1,100 MW in the block forward market in June and about 1,800 MW in the other summer months out of a limit of about 3,000 MW allowed by the CPUC. The net volume of sales in the SP15 block forward market indicates that SCE may have hedged about 1,750 MW of its 2,200 MW limit in June, and about 3,000 to 3,500 MW of its 5,200 MW limit for the months of July to September.

Figure 12. How Are Market Costs Allocated Among Consumers, IOUs and other Market Participants?



The figure above shows an estimate of how total market costs incurred in June could ultimately impact different customers, IOU shareholders, and other market participants.

At least 35% of costs incurred by the state's major IOU's (PG&E and SCE) are paid "to themselves" as a result of generation owned by these utilities. In making this calculation, revenues from IOU generation was estimated based on actual market schedules and market clearing prices.

Another 6% of costs in June were hedged through 2,850 MW sold in the PX block forward markets. The portion of total market costs already covered or hedged by block forward market purchases was estimated in Figure 12 by valuing block forward purchases at the PX Day Ahead price.

Remaining costs for the state's two major IOUs are partially covered in the frozen retail rates currently charged to PG&E and SCE customers. For instance, while costs for unhedged energy procured by the two major IOUs in June may average about 16.6 cents/kWh, retail rates for the major IOUs include approximately 6.27 cents/kWh for recovery of energy charges and CTC recovery. Consequently, to provide an indication of the portion of energy cost increases that may impact shareholders of the major IOUs, Figure 12 further reduces the total "unhedged" costs incurred by the major IOUs by the approximate portion of these costs that are covered in current retail rates (~6 cents out of an average cost of 16.6 cents).

Due to the rate freeze, costs not hedged or recovered through frozen rates may ultimately have the effect of delaying repayment of the Competitive Transition Charge (CTC), and/or the ultimate level of CTC recovered by IOU's. For this reason, this portion of total market costs is labeled "Potential Negative CTC Recovery" in Figure 12.

SDG&E, which has repaid its CTC and is no longer under a rate freeze, is estimated to account for about 6% of total market costs in June. Direct access customers are estimated to account for about 17% of total loads and costs. Many of these loads are likely to be covered by bilateral contracts, so that cost impacts between customers and Energy Service Providers (ESPs) depend on the nature of each contract and the extent to which supplies for these customers were hedged in the forward markets.

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IV. Underscheduling of Loads and Supply

During June, the total amount of load and generation scheduled in the Day Ahead and Hour Ahead market consistently hit a plateau of about 35,000 MW, with any remaining load above this level being met in the real time imbalance market (see Figure 5 and 6 in previous section). Figure 13 summarizes the overall pattern of underscheduling during the month of June at different load levels.

Figure 14 and the accompanying text summarize several of the key factors creating large under-scheduling of loads and generation in the ISO's real time imbalance market. Recent PX market prices and volumes -- as well as sample aggregate supply and demand curves released by the PX -- indicate that despite recent "shifts" in aggregate demand (reflecting an increased willingness-to-pay in the forward markets), the ability of buyers to increase purchases in the PX Day Ahead markets is severely limited by the nearly vertical slope of the PX supply curve around the 30,000 MW level. Due to the nearly vertical slope of supply offered in the PX at this level, any outward shift in demand simply increases the Market Clearing Price (MCP) significantly, with a minimal increase in the Market Clearing Quantity (MCQ). As a result, large buyers have an incentive to minimize overall costs by limiting their purchases in the PX market when overall aggregate demand intersects supply at this nearly vertical portion of the supply curve. Thus, the massive underscheduling that is occurring during high load hours represents a failure of both supply and demand to clear and schedule in the forward markets.

Within the current design of California's energy markets, the ability of buyers to limit the prices they are willing to pay in the forward energy markets and shift demand into the real time imbalance market represents one of the major ways that large buyers can limit overall costs and defend against market power. Other tools for "defending" against high prices due to both market power and scarcity include demand elasticity, and the ability of buyers to procure supply in forward markets and through bilateral contracts. However, the ability of buyers to utilize these tools is currently limited significantly due to regulatory constraints and the relatively immature nature of California's recently deregulated energy market.

One option that is sometimes suggested for reducing the reliability problems associated with under-scheduling of loads and generation is to simply require all (or a very high percentage) of actual expected loads and available generation to be scheduled in the forward markets. As illustrated in Figure 15 and the accompanying discussion, this is likely to simply cause the PX price to clear at $2,500 during many hours when prices now clear in the $500 to $750 range.

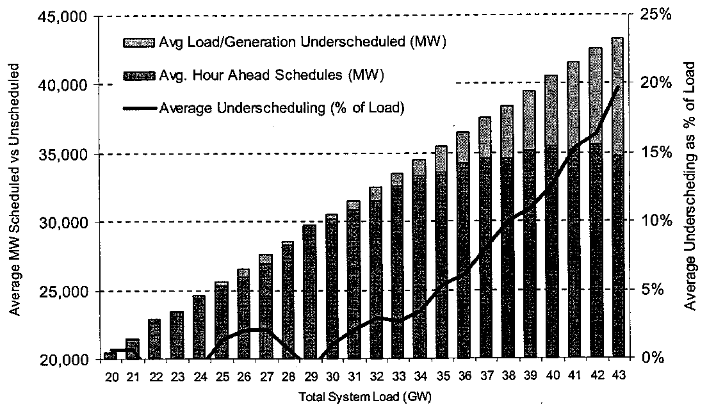
Another market design feature that may prevent buyers from paying the higher prices necessary to purchase and schedule additional load in the PX Day Ahead market results from the combination of:

(1) a requirement by the PX that adjustment bids for decremental demand submitted with initial schedules for load purchased in the PX be higher than the PX unconstrained price, and

(2) the ISO's requirement that adjustment bids not exceed the current $500 price cap (set at $750 during the June price spikes).

In combination, these two constraints can expose buyers in the PX to extremely high constrained prices in the event of congestion. For instance, if the unconstrained price is higher than the ISO's price cap, buyers in the PX are unable to submit adjustment bids which meet both the PX requirement that adjustment bids be *higher* than the unconstrained price, as well as the ISO's requirement that adjustment bids be *lower* than the ISO's price cap. This creates the risk that in the event of congestion, insufficient adjustment bids would

Figure 13. Average Underscheduling of Loads and Generation by System Load Level (June, 2000)



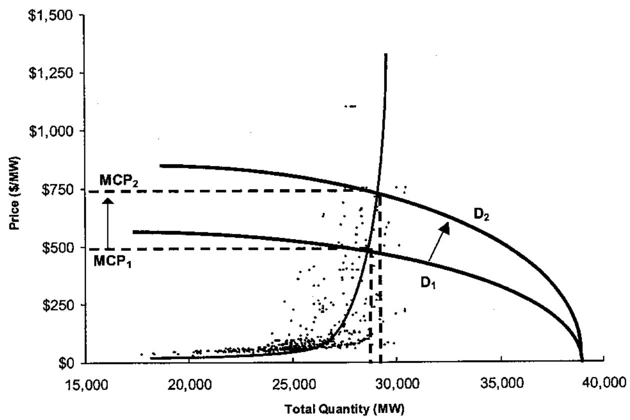
As previously shown in this report, the total amount of load and generation scheduled in the Hour Ahead Schedules consistently hit a plateau of about 35,000 MW, with any remaining load above this level being met in the real time imbalance market (see Figures 5 and 6). The 35,000 MW plateau of load and generation scheduled in the Day Ahead and Hour Ahead markets represents a maximum of about 30,000 MW scheduled in the Day Ahead PX market, plus a maximum of approximately 5,000 MW scheduled during peak hours from other Schedule Co-ordinators (SCs). Loads and generation scheduled by other SCs includes municipals, direct access customers, and other non-IOU loads and generation.

The figure above summarizes the average amount of underscheduling at different system load levels in June, in terms of total average MW (represented by bars charted on left axis) and as percentage of total system loads (represented by the line charted against the right axis).

Underscheduling of loads and generation in June was minimal below 30,000 MW, and averaged less than 5% of total loads up to load levels of about 35,000 MW. However, virtually all load and generation over 35,000 MW unscheduled in the Day Ahead and Hour Ahead markets.

The average amount of real time energy imbalance climbed from about 10% of total system loads at 38,000 MW, up to about 20% of total system peak loads (or nearly 9,000 MW) during hours when system load exceeded 43,000 MW. When system loads peaked at 43,447 MW on June 16 (Hour 16), total loads exceeded final Hour Ahead schedules by 9,064 MW, or about 21% of total system load.

Figure 14. Illustrative Example of Supply and Demand in PX Day Ahead Market



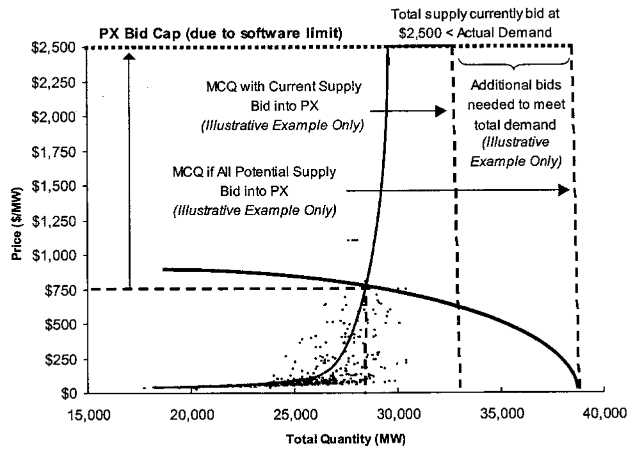
The figure above illustrates several of the key factors creating large under-scheduling of loads and generation in the ISO's real time imbalance market. Due to the very steep slope of the PX supply curve around the 30,000 MW level, any outward shift in the demand curve (representing an increased willingness of one or more buyers to purchase energy at relatively high prices) results in a significant increase in the Market Clearing Price (MCP), but only a small increase in the Market Clearing Quantity (MCQ).

Since the MCP is applied to the entire quantity purchased in the PX Day Ahead, large buyers have an incentive to limit their demand (or at least the portion of demand bid at very high prices) when the overall aggregate demand curve is intersecting the supply curve within this steeply sloped (almost vertical) portion of the PX supply curve. Although this sometimes requires a large portion of demand to be met in the real time market at potentially higher prices, this strategy limits overall costs paid by large buyers.

Within the current design of California's energy markets, the ability of buyers to limit the prices they are willing to pay in the forward energy markets and to shift demand into the real time imbalance market represents one of the major ways that large buyers can limit overall costs and defend against market power. Because of the nearly vertical slope of the PX supply curve at the 30,000 MW level, the massive underscheduling that is occurring during high load hours represents a failure of both supply and demand to "clear" and schedule in the forward markets. Figure 15 provides additional discussion of this issue.

In this illustrative example, the shape of the PX supply and demand curves is approximated based on actual data for several hours in June recently released by the PX (see Footnote 2), as well as publicly available data on the Market Clearing Price and Quantity in the PX Day Ahead market during peak hours in June (represented by red dots in the figure above). Actual aggregate PX demand and supply curves are only released after a six-month lag period.

Figure 15. Why Not Simply Require Load to Be Scheduled in the Forward Market?



One option that is sometimes suggested for reducing the reliability problems associated with under-scheduling of loads and generation is to simply require all (or a very high percentage) of actual expected loads and available generation to be scheduled in the forward markets.

The figure above illustrates several of the numerous problems with this approach. First, it must be remembered that over the short-term, many buyers (including California's major UDCs) are currently limited in their ability to meet demand by purchasing through the entire range of forward markets, ranging from regional futures and spot markets, to "traditional" bilateral contracts with individual suppliers. As a result, the state's UDCs must – over the short-run at least – continue to look to the PX Day Ahead market to meet a large portion of their demand.

Demand bid curves recently released by the PX suggest that the amount of demand currently being bid into the PX during peak hours meets or exceeds total actual loads, but that much of this demand is simply bid at a relatively low price so that it is very unlikely to clear under current market conditions (see Footnote 3, page 2). In order to ensure that their demand is scheduled in the forward markets, buyers would need to bid their total expected net demand into the PX as "price takers" (i.e. at the maximum bid price of $2,500/MW allowed for both supply and demand bids due to the PX's software). Unless a lower bid cap was placed on the PX market (and some way of requiring generators to bid capacity into this market was established), this would simply cause the PX price to clear at $2,500 during many hours when prices now clear in the $500 to $750 range.

Supply bid curves recently released by the PX suggest that the amount of supply currently being bid into the PX even at the $2,500 level during peak hours is well below the total available supply (including imports) and the level of supply needed to meet total demand (see Footenote 2). However, additional supply may be attracted to the PX if virtually all demand was required to bid into the PX as "price takers" or at a price comparable to the potential opportunity cost of capacity in other ISO and regional markets.

be available to relieve congestion, so that the Default User Charge (DUC) equal to the ISO price cap would be in effect. Under the Default User Charge, buyers are exposed to very high congestion charges of $500.

This feature of the market design represents the likely explanation for many hours in late June and late July when the PX market has clears slightly below the ISO's price cap (e.g. $749 or $499). This allows buyers to submit adjustment bids for decremental demand at a price slightly higher than the unconstrained price, which is still equal to or lower than the ISO price cap on adjustment bids.

The issue of the whether or not the adjustment bid cap should be modified or "unlinked" from the real time energy price cap requires careful examination, in order to avoid potential adverse affects which lead to the setting of a single price cap for both real time energy and adjustment bids.

Figures 16 through 18 provide an examination of underscheduling by UDC area, based on aggregate total Hour Ahead Schedules and Final Loads within each UDC area. Thus, data in Figures 16 through 18 include both IOU loads and other entities within each UDC area.

- As shown in Figures 16 through 18, the level of underscheduling is highest (in terms of total MW and as a percent of actual load) in the PG&E area, followed the SCE area, with a relatively small amount of underscheduling in the SDG&E area.
- This pattern may largely reflect the fact that the incentive for buyers to limit purchases in the Day Ahead Market is largely a function of each buyer's size: while larger buyers can have a very big impact on market clearing prices, smaller buyers have much less impact, and therefore have less incentive to limit purchases.
- In addition, it is important to note that smaller buyers benefit from this pattern, in that they are able to meet a relatively large portion of their demand in the PX market at lower prices due to the purchase strategies of larger buyers.

The following section of this report discusses the impact that purchases of large quantities of deviation replacement reserve at high prices often hitting the $750 price cap) appears to have had on under-scheduling of both load and generation during June.

Figure 16. Underscheduling By UDC Area

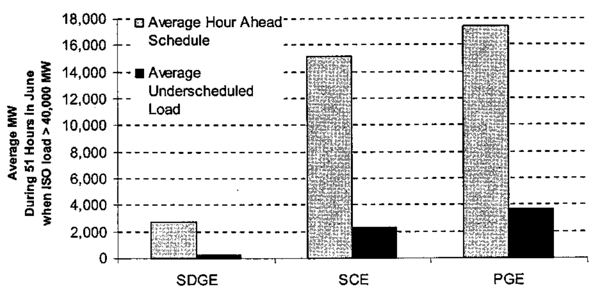


Figure 17. UDC Area Underscheduling By System Load Level
Underscheduling As a Percentage of Total UDC Area Load

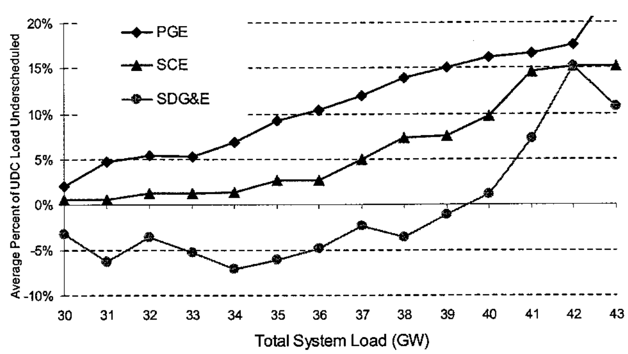
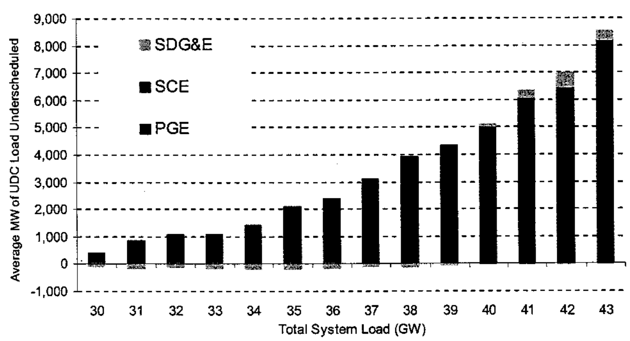


Figure 18. UDC Area Underscheduling By System Load Level
Total Average MW Underscheduled by UDC Area



V. Purchase of Replacement Reserve

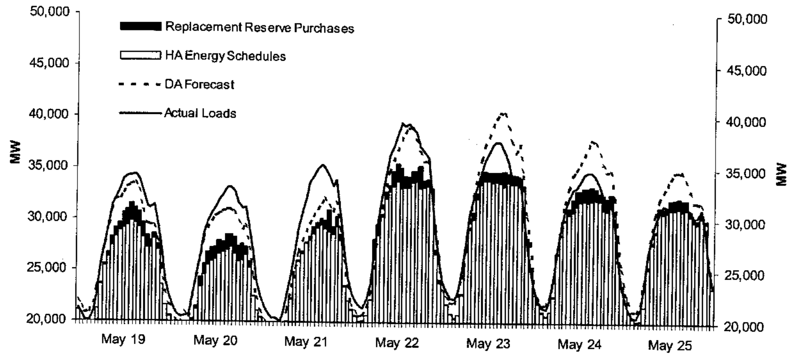
One of the key adjustments made by the ISO following the May 22 events was to implement an operational practice of defending against significant underscheduling of loads (and avoiding potential *out-of-market* purchases) by purchasing large volumes of replacement reserve capacity to narrow the gap between scheduled and forecasted loads. However, market performance during June indicates that the practice of purchasing replacement reserve based on the difference between scheduled and forecasted loads may have instead contributed to the development and/or perpetuation of a spiral of price spikes and underscheduling.

- Despite day ahead forecasted loads of up to 45,000 MW on the three day period from June 13-15, the amount of load and generation scheduled in the forward energy markets remained at approximately 35,000 MW. (See Figure 19)
- In contrast to the May 22 event, during the June 13-15 period the ISO purchased large quantities of Replacement Reserve (up to 7,000 MW) based on the difference between forecasted loads and generation/loads scheduled in the Day Ahead market, as shown in Figure 19.
- Purchasing this Replacement Reserve was intended to serve two purposes: (1) provide a firmer source of supply needed to meet projected demand (i.e. compared to supplemental energy bids, which have no obligation to deliver), and (2) provide an incentive for load to be scheduled in the forward market, in order to avoid being billed for the additional cost of this Replacement Reserve.
- The large volumes of Replacement Reserve purchased by the ISO accomplished this first objective by significantly reducing – but not entirely eliminating — the need to rely on "uncommitted" generation from supplemental energy bids.
- In practice, however, it appears the purchase of significant amounts of Replacement Reserve under the extremely tight supply and demand conditions existing during the June 13-15 period may have created an additional incentive for suppliers to withhold capacity from the Day Ahead PX market (by not bidding, or bidding at extremely high prices that buyers are unwilling to pay), and shift additional capacity into the Ancillary Services (particularly Replacement Reserve) and real time markets. As previously noted, suppliers can benefit from this strategy in two ways: they may be highly likely to receive a real time energy price higher than the Day Ahead PX price, and can receive both a capacity and energy payment by supplying Ancillary Services.

Figure 20 illustrates the effect that tight demand/supply conditions – coupled with the purchase and dispatch of large quantities of replacement reserves – may have had on PX market energy prices during the June 13-15 period. As shown in Figure 20, significant amounts of under-scheduling and real time price spikes occurred during both the May and June heat waves. However, PX Day Ahead prices rose significantly higher during the June heat wave, particularly in the days after large quantities of replacement reserves were purchased by the ISO.

Figure 21 compares the market clearing prices for Replacement Reserve during the May and June heat waves, along with the quantities of Replacement Reserves purchased. As shown in Figure 21, Replacement Reserves prices ranged from $250 to $500 during the peak hours of May 22 through 24, and spiked in the Hour Ahead market several hours on May 22-23 when the ISO procured significant amounts of Replacement Reserve in the Hour ahead market. During the June heat wave, however, the price of Replacement Reserve cleared at the $750 price cap during virtually all peak hours in both the Day Ahead

Figure 19. Purchases of Replacement Reserve
May vs. June Heat Waves



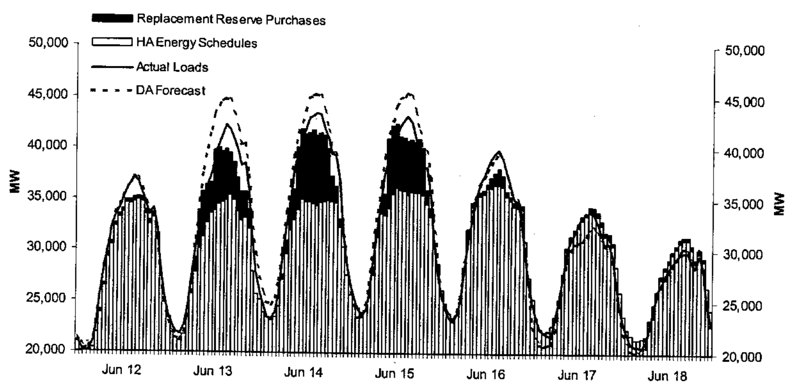


Figure 20. PX vs Real Time Energy Prices
May vs. June Heat Waves

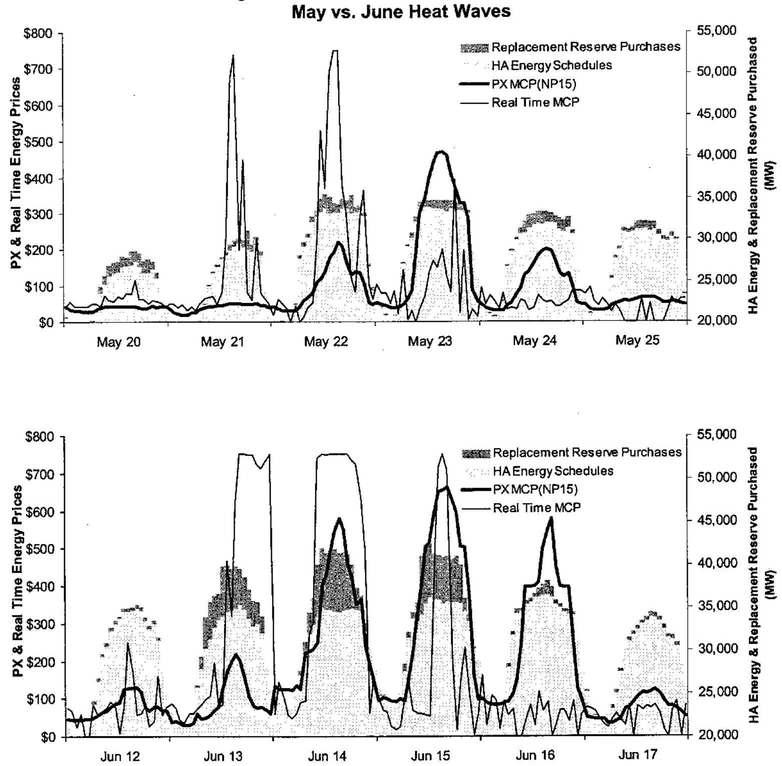
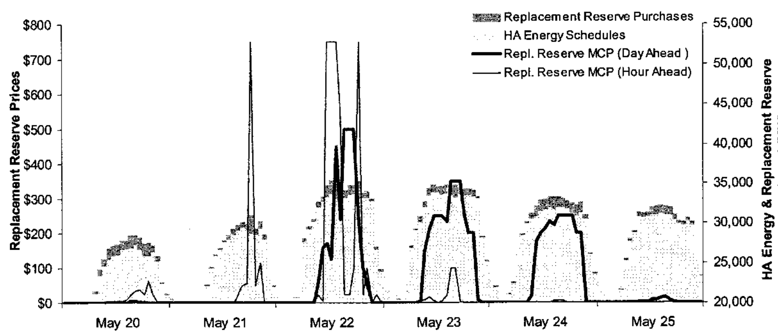
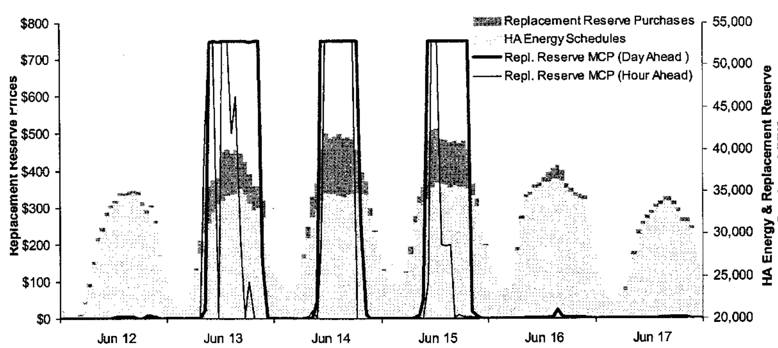


Figure 21. Replacement Reserve Purchases and Prices
May vs. June Heat Waves

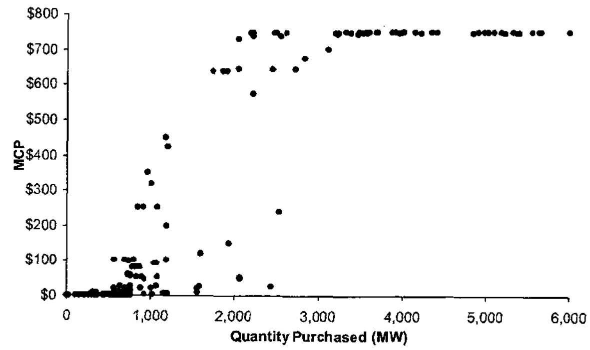




and Hour Ahead Markets, as the ISO purchased virtually all supplies offered in both these markets over this three-day period. Figure 22 illustrates the steepness of the supply curve and relatively large quantities of Replacement Reserve purchased by the ISO during June. Additional information on the bid prices of supply offered in the Replacement Reserve Market is provided in Section VI.

The purchase of replacement reserves is intended, in part, to discourage buyers from under-scheduling in the forward markets. However, as discussed in Section III of this report, experience during the June heat waves suggests that – at least over the short run—there may be little buyers can do to purchase additional energy in the forward markets. From the perspective of large buyers, this creates an incentive to continue the careful balancing act of attempting to under-schedule some portion of demand in the forward energy markets in order to minimize overall payments. Figure 23 and the accompanying discussion summarize the overall impact that deviation Replacement Reserve purchases and prices had on effective prices in the PX Day Ahead and ISO real time market in June.

Figure 22. Replacement Reserve Purchases and MCP Prices (June)
Day Ahead Market



Hour Ahead Market

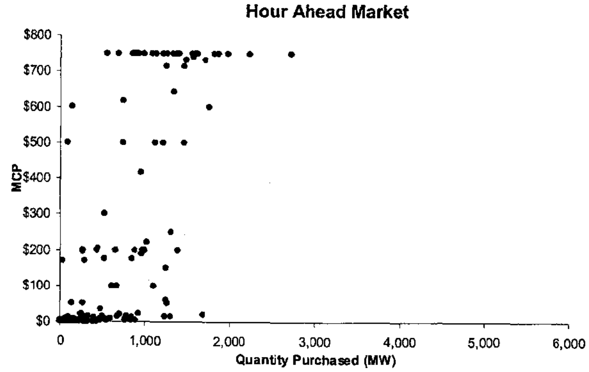
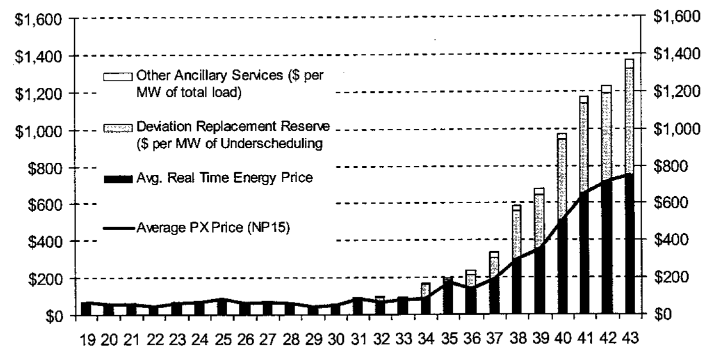


Figure 23. Replacement Reserve Purchases and MCP Prices (June) Day Ahead Market



The figure above compares the average PX Day Ahead price and ISO real time price at different load levels, along with the average estimated additional cost for load met in the real time market due to Deviation Replacement Reserve purchases. The average Deviation Replacement Reserve charge per MWh of load met in the real time market at each load level was estimated based on total Replacement Reserve costs, divided by the total difference between actual system loads and final hour ahead schedules. From the perspective of buyers, the effective cost of load met in the real time market includes both the real time energy price, plus Deviation Replacement Reserve charges. Thus, while average PX and real time prices tracked very closely at virtually all load levels in June, the effective price buyers in the real time market exceeded the PX price during load levels above 35,000 MW. At load levels of 40,000 MW and above, Deviation Replacement Reserve charges represent an estimated $400 to $500/MW, with average prices in both the PX and real time market nearing the $750 price cap at load levels of 42,000 MW and above. During the first two summers of operation, prior to implementation of Deviation Replacement Reserve charges real time prices consistently hit the $250 price cap at very high load levels, but PX prices rarely exceeded $150 due the limited demand in the PX at prices above this level.

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VI. Regional Energy Markets

This section examines prices and supply trends in other regional energy markets, which can play a pivotal role in California's energy markets during tight supply and demand conditions.

Imports and Exports

Average imports and exports between the ISO system of surrounding regional markets during peak load hours of June-August 1999 and June 2000 are summarized in Figures 24 and 25. More detailed information is provided in Table 3. As shown in these figures:

- Net imports into the ISO decreased by approximately 1,000 MW during the 51 hours in June with ISO system loads of 40,000 compared to the 56 hours during the summer 1999 months with loads of at least 40,000 MW. As shown in Figure 24 and Table 3, the bulk of this drop in net imports stems from increased exports to southwestern control areas.
- While total net imports of energy and reserve capacity from the Northwest has actually increased, the amount of energy scheduled in the Day Ahead and Hour Ahead market from the Northwest has dropped by over 1,800 MW (see Figure 24 and Table 3). This reflects a significant shift away from the forward markets, toward the Replacement Reserve and real time supplemental energy markets. During tight supply and demand conditions, this shift has created significant uncertainty about the available imports to meet demand in real time and has led the ISO to increase purchases of Replacement Reserves.
- Overall, the combined effect of increased exports to the southwest and decreased scheduling from the northwest energy in the forward markets has been to reduce total net energy imports scheduled in the Hour Ahead market by over 3,000 MW (see Figure 25 and Table 3). As noted above, this has created significant uncertainty about the availability of sufficient supply to meet demand in real time during high load conditions.

Comparison of Regional Energy Market Prices

Regional energy markets in which supply and demand in the ISO system may be transacted include:

- NYMEX futures markets for monthly blocks of energy for peak hours (known as 6x16 blocks).
- The PX block forward market for similar blocks of peak energy
- The PX Day Ahead market for hourly
- Daily spot markets, in which blocks of energy may be bought or sold at the beginning of each operating day, and
- The ISO's hourly real time imbalance energy market.

Prices in the different regional energy markets track closely, particularly when averaged over "6 x 16" peak hour blocks on a monthly basis, as shown in Figure 26. One notable exception to this trend in May and June was NYMEX future prices for monthly energy blocks, which closed significantly lower than prices in the daily spot and hourly PX and ISO energy markets. This may be attributed to the unexpectedly high prices experienced in these months due to the combination of factors examined in this report.

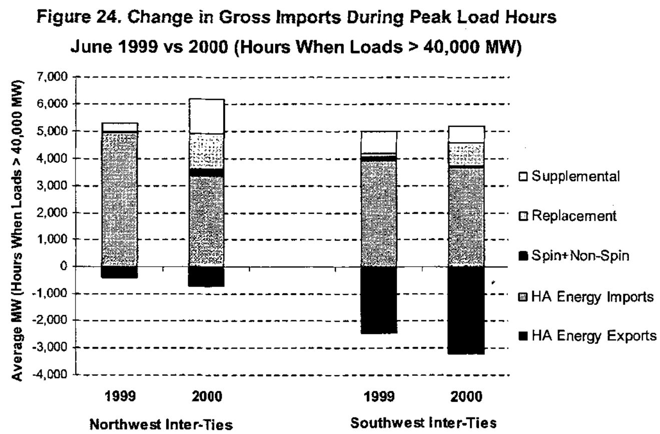


Figure 24. Change in Gross Imports During Peak Load Hours
June 1999 vs 2000 (Hours When Loads > 40,000 MW)
Average MW (Hours When Loads > 40,000 MW)
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
-1,000
-2,000
-3,000
-4,000
1999
2000
Northwest Inter-Ties
1999
2000
Southwest Inter-Ties
Supplemental
Replacement
Spin+Non-Spin
HA Energy Imports
HA Energy Exports

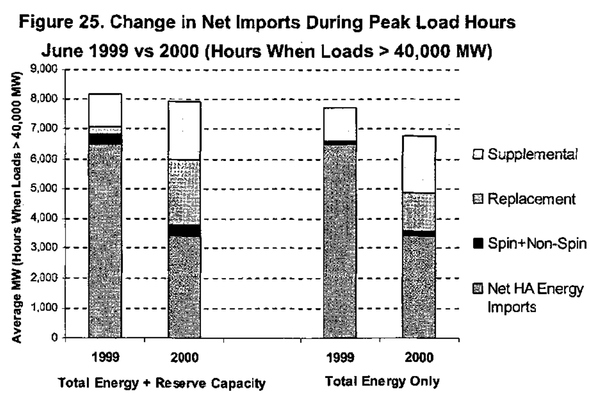


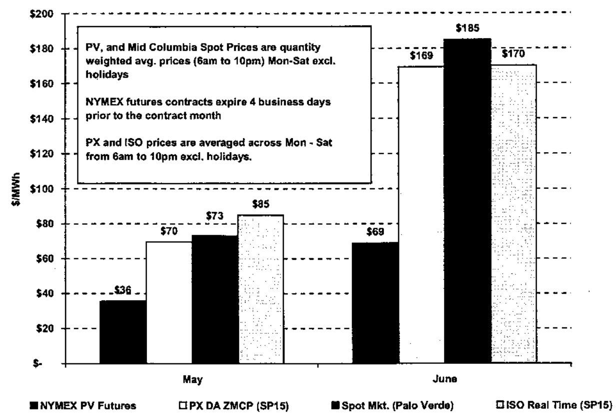
Figure 25. Change in Net Imports During Peak Load Hours
June 1999 vs 2000 (Hours When Loads > 40,000 MW)
Average MW (Hours When Loads > 40,000 MW)
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
1999
2000
Total Energy + Reserve Capacity
1999
2000
Total Energy Only
Supplemental
Replacement
Spin+Non-Spin
Net HA Energy Imports

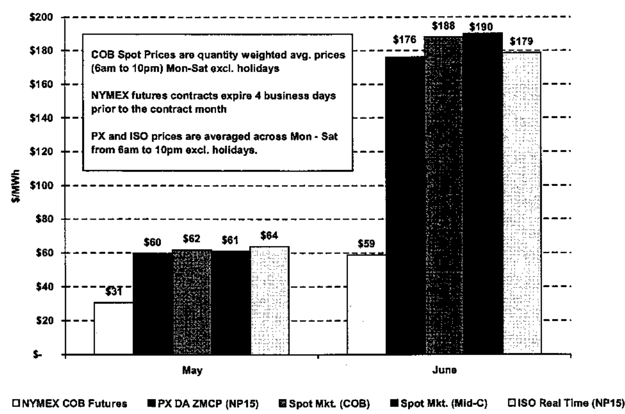
Table 3. Change in Gross and Net Imports – June 1999 vs 2000 During Peak Hours (Loads > 40,000 MW)

		Hour Ahead Energy Schedules			Oper. Reserves (Spin & Non-spin)		Replacement Reserve		Suppl.	Total HA	Total	Total
Region	Year	Imp	Exp	Net	Capacity	Energy	Capacity	Energy	Energy	Capacity	Capacity	Energy
NW	1999	4,930	408	4,522	21	0	30	1	285	4,573	4,857	4,807
NW	2000	3,348	684	2,663	263	108	1,300	617	1,288	4,227	5,515	4,676
	Change	-1,583	276	-1,859	242	108	1,270	616	1,003	-346	657	-132
SW	1999	3,898	2,439	1,459	191	26	125	31	777	1,776	2,553	2,293
SW	2000	3,638	3,226	412	83	46	861	607	623	1,356	1,978	1,687
	Change	-260	787	-1,048	-108	20	736	576	-154	-420	-575	-606
CA	1999	1,072	289	783	128	29	58	9	57	970	1,027	878
CA	2000	827	193	635	14	9	41	22	33	690	723	699
	Change	-245	-96	-149	-114	-20	-18	12	-23	-280	-304	-179
CFE	1999	0	250	-250	0	0	0	0	0	-250	-250	-250
CFE	2000	3	277	-274	0	0	0	0	1	-274	-274	-274
	Change	3	27	-25	0	0	0	0	1	-25	-24	-24
All	1999	9,900	3,386	6,515	340	55	214	41	1,119	7,069	8,187	7,729
All	2000	7,815	4,380	3,435	361	163	2,202	1,246	1,944	5,998	7,942	6,788
	Change	-2,085	994	-3,079	20	108	1,988	1,205	826	-1,071	-245	-941

Notes:
1. Regions: NW = Northwest, SW=Southwest, CA=Internal California Inter-ties, CFE = Mexico
2. Year 1999 data based on hourly averages for 56 hours between June-August 1999 when total ISO loads > 40,000 MW.
3. Year 2000 data based on hourly averages for 51 hours in June 2000 when total ISO loads > 40,000 MW.

Figure 26. Comparison of Regional Energy Market Prices





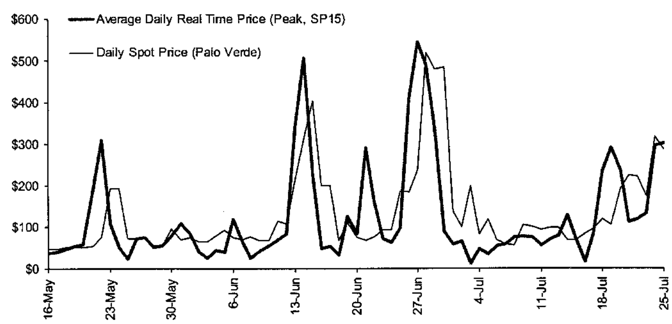
A key question facing the ISO in the context of addressing shortages of scheduled supply and setting the price cap involves the degree to which the ISO's real time market drives or follows other regional supply markets. On one hand, since the ISO's real time market is the final energy market chronologically and is marked by very limited demand elasticity, the real time market may, in effect, set the opportunity cost for both buyers and sellers in other forward markets. Thus, whether prices in the real time market reflect true scarcity or market power, the resulting prices nevertheless represent an opportunity cost that is likely to affect prices in other markets. At the same time, since the ISO's real time market is the final energy market to clear chronologically, during periods of true scarcity most available supplies may be committed through other markets or bilateral transactions unless suppliers expect to receive comparable or higher prices in the real time market. In this manner, real time prices may be driven by other markets during periods of true scarcity of supply.

The remainder of this section provides a brief, preliminary examination of the potential relationship between the ISO real time market and other markets:

- **Spot Market vs Real Time Prices.** First, average real time prices are compared to daily spot market prices to examine the degree to which prices in these markets appear to track, diverge and follow one another. When comparing prices in these two markets, it is important to note that hourly real time prices must be averaged over the 16 hour period used to calculate spot market price indices that are used to report prices in these markets. As shown in Figure 27, prices in these markets track closely, but tend to diverge during high priced periods, with spikes in spot prices lagging behind spikes in the real time market. Prices in the two markets continued to track in a similar manner in July, following the lowering of the ISO's price cap from $750 to $500, with overall prices in both markets lower even during high loads during the week of July 18-25. Together, these trends provide limited indication that spot market prices (for transactions at the beginning of each operating day) may tend to be driven in large part by the previous day real time prices.
- **Impact of Price Cap Decision on Futures Prices.** Futures prices can also be examined to assess whether these prices appear to have been affected by price decisions about the price cap in the ISO real time market. Figure 28 shows a time series of electricity and gas futures prices up to and shortly after the recent Board meetings concerning price caps. As shown in Figure 27, the rise in futures prices from April to early June is closely correlated with gas futures prices, but jumped more sharply following the price spikes in mid June. Futures prices actually rose sharply for several days after the price cap was lowered to $500, before falling in conjunction with gas futures prices just prior the July 6, ISO Board meeting at which price caps were kept at $500. Thus, futures prices also appear to provide a limited and mixed indication of the relationship between these markets.

Figure 27. Comparison of Daily Spot vs Real Time Price

Palo Verde and SP15



COB and NP15

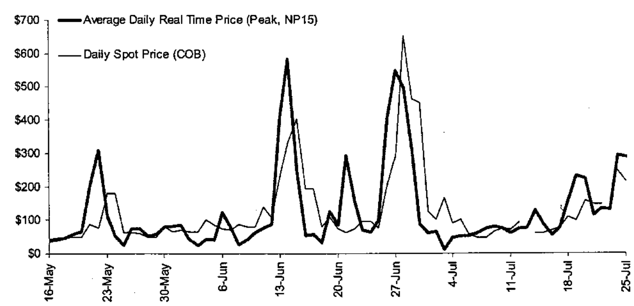
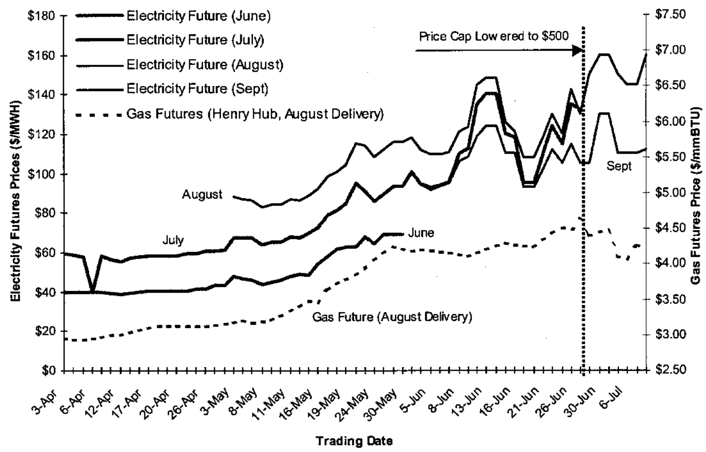
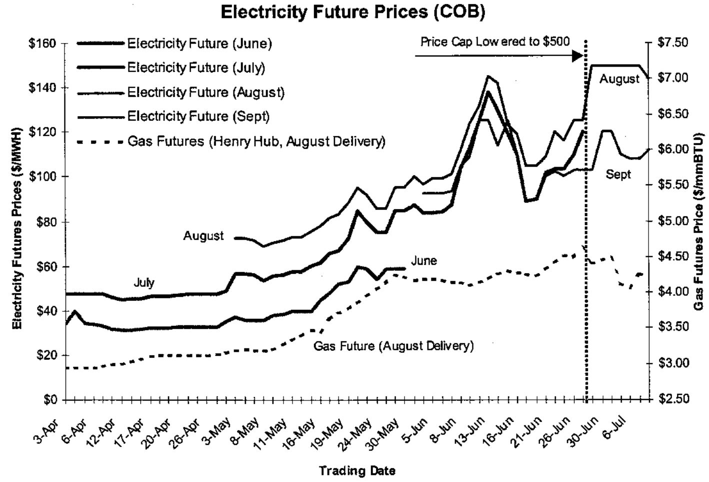


Figure 28. Electricity Future Prices (Palo Verde)



Electricity Future Prices (COB)



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VII. Market Power and Supply Scarcity

This section examines the issue of market power vs. supply scarcity in the context of the recent price spikes, as well as the behavior of market participants in causing price spikes. Analysis of supply and demand conditions presented in this section indicate that the persistent price spikes in June and July reflect both the exercise of market power, as well as absolute scarcity of supply during numerous hours.

Available Supply vs. Total System Demand

Figures 29 through 31 compare hourly supply and demand conditions for three periods during May and June when prices spiked in California's markets. Figure 29 provides a discussion of supply and demand conditions during each of these periods. For this analysis, total supply was estimated as follows:

> For the thermal units of non-utility owners, total available supply was based on the maximum operating level of each unit (as indicated in historical metered information) that was in operation and/or bid into the ISO markets. [10]

> For all other units within ISO control area, total supply was calculated for each hour based on total actual generation (including scheduled energy, real time energy dispatched and uninstructed deviations), plus any additional (non-dispatched) capacity bid into the market as Ancillary Services or Supplemental Energy markets. This assumption reflects the fact that most of these units are hydro, QFs or utility-owned generation which is operated and bid into the market during high load hours whenever it is available.

> For imports, available supply was based on final hour ahead schedules (for energy and ancillary service capacity), plus supplemental energy bids and any out-of-market purchases made during periods of peak demand. For imports, both energy and capacity needed to be estimated based on schedules and dispatches, rather than metering data, due to the lag or lack of reliable metering data for many paths at this time.

> The sum of estimated generation from all sources was reconciled with actual system loads as reported by the ISO based on telemeter data in order to account for system losses and any errors due to missing or inaccurate metering data. [11]

Total system demand for energy and capacity was calculated as follows:

> Total realized system demand (as measured by the ISO based on telemeter data) was increased to reflect any load curtailments reported by UDCs.

> Total unmanaged demand for energy was then increased by 10 percent to reflect capacity required for Ancillary Services during peak periods (approximately 3% of upward regulation plus 7% for operating reserve, including spinning and non-spinning reserve).

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[10] If metering information, final energy and ancillary schedules, and supplemental energy bids indicated a unit was available during any hour of a day, it was assumed the unit's full capacity was available for that operating day.

[11] For virtually all peak hours with relatively tight supply and demand conditions, the reconciliation the sum of unit level estimates of generation (plus import schedules) was between approximately 1 to 3% of the ISO official estimate of system loads. This is within the range expected to line losses, in combination with other any errors due to missing or inaccurate metering data

Figure 29. Demand and Supply Conditions (May 20-25)

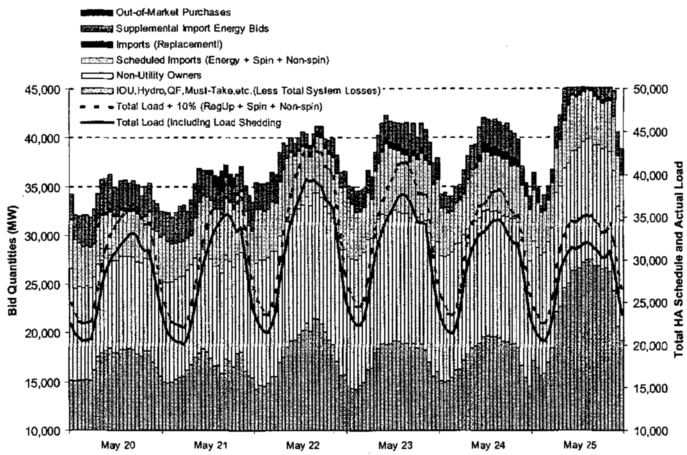


Figure 29 compares total system demand and supply conditions for the period from May 20 to May 25. Total demand is shown in terms of system loads, as well as total system demand for capacity, which is estimated based on total loads plus 10% for ancillary services (Regulation Up, Spinning and Non-Spinning Reserve).

Supply from within the ISO control area is shown for two different categories: major non-utility owners of thermal generation divested by utilities, and all other generation, which includes hydro, QFs, and other utility-owned generation. Supply from major non-utility owned thermal units is based on maximum generating capacity of units available or in operation. Supply from other resources is based on actual generation and capacity scheduled or bid into the ISO's markets. This approach is used to reflect the uncertainty and variability of actual capacity available each hour from hydro units, QFs and many other sources of supply, and the assumption that under peak load conditions the owners of these units have an incentive to schedule or bid all available capacity into the market.

Supply from imports is shown in terms of the following categories. Scheduled imports include energy plus operating reserves (spin and non-spin) scheduled in the Day Ahead and Hour Ahead markets. Import of Replacement Reserve is also shown to highlight the degree to which additional firm generation from other control areas was secured through purchases of large quantities of Deviation Replacement Reserve in June. Finally, we show Supplemental Energy Bids and Out-of-Market purchases from suppliers outside the ISO control area to highlight the critical role these supplies have played in allowing the ISO to meet demand during peak load conditions.

Figures 30 through 33 show similar comparisons of loads and supply during peak load periods in June, when the ISO experienced numerous hours of absolute scarcity of supply.

Figure 30. Demand and Supply Conditions (June 12-16)

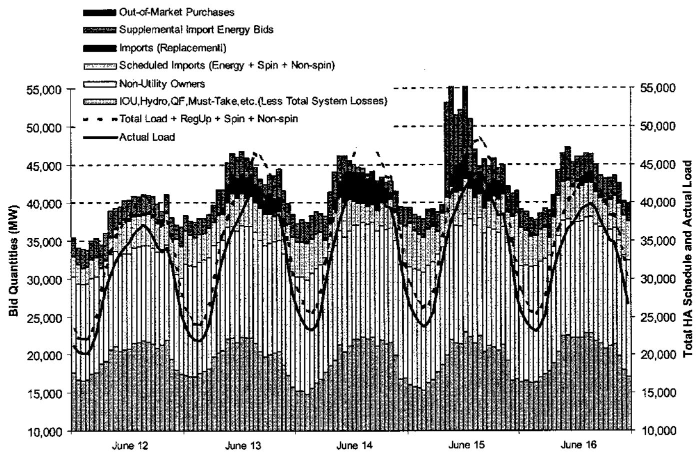


Figure 31. Demand and Supply Conditions (June 26-30)

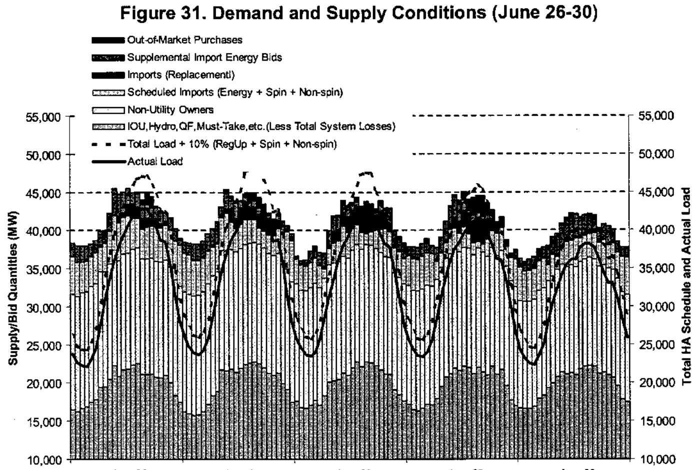
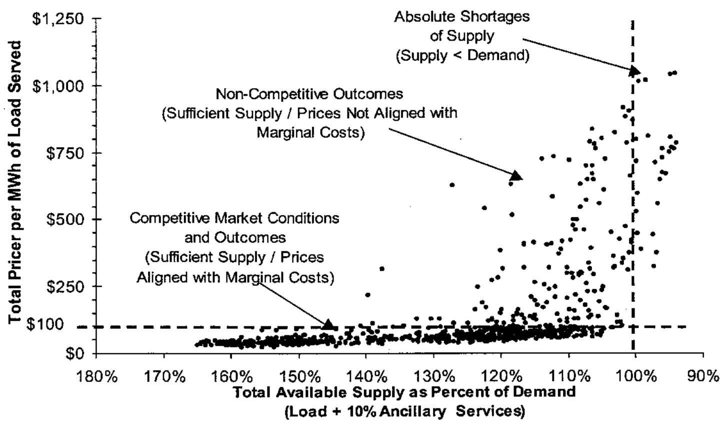


Figure 32. Hourly Demand and Supply Conditions and Total Cost of Load Served (June 2000)



The figure above compares the total price per MWh of load served in the ISO system at different supply and demand conditions, expressed in terms of total available supply as a percent of demand. The total price per MWh of load served is based on the prices and quantities purchased in the different energy and ancillary service markets. Additional details of this analysis were presented in Section II of this report. Total available supply and system demand is based on analysis previously described in this section of the report.

Also shown in Figure 32 are two reference lines that may be used to categorize different market outcomes. Hours to the right of the vertical dotted line represent hours when total available supply was insufficient to meet demand. The horizontal dotted line highlights hours where market outcomes appear to reflect competitive outcomes in which prices are not significantly in excess of the marginal operating cost of the highest cost thermal units within the ISO system. Together, these two lines also highlight market outcomes that are likely to reflect non-competitive market outcomes, or prices significantly in excess of system marginal costs despite sufficient supply.

Table 4 provides a statistical summary of data shown in Figure 32. The Executive Summary of this report and later sections of this report provide additional discussion of the issue of market power vs. scarcity.

Table 4. Summary of Demand and Supply Conditions And Total Cost of Load Served (June 2000)

Available Supply as Percent of Demand	Number of Hours: Hours	Pct	Avg. Load (MW)	Avg. Costs $/MWh	Total cost (Millions)	Percent of Total Costs
< 100%	27	4%	42,651	$709	$807	22%
100-110%	106	15%	37,853	$324	$1,335	37%
110-120%	187	26%	33,202	$121	$779	22%
120-130%	134	19%	29,813	$83	$353	10%
>130%	266	37%	23,507	$50	$321	9%
	720				$3,595	

Other Indicators of Market Power

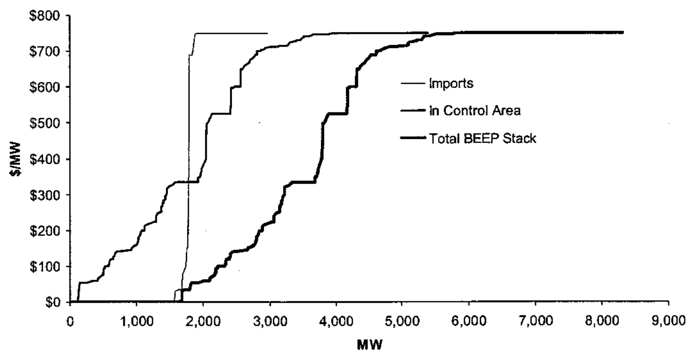
Analysis shown in the previous section indicates that there are many hours of extremely high prices when supply and demand are relatively tight, but there is no apparent shortage of supply. During these hours high prices are most likely the result of market power. The presence of market power can be verified by a high bid price over variable cost by many suppliers in the ISO's markets. The highest variable cost of in-state generators is below $100/MWh, while many suppliers routinely bid a significant part of their capacity at $750 (the price cap level). These bids had to be selected to meet the demand during high load periods.

Figure 33 shows a typical supply bid curve for all sources of real time energy during a peak hour of the June 26-30 price spikes. During these hours, a maximum of about 35,000 MW were scheduled in the Day Ahead and Hour Ahead markets, so that 5,000 MW or more of real time energy was needed to meet demand at load levels of 40,000 and higher.

As shown in Figure 33, observed market power can be the result of combined bidding activity of in-state and out-of-state generators. The available data and tools do not allow detailed analysis of the market power of out-of-state generation owners. The CA ISO, however, is not aware of any acute regional shortages in most of the high price hours (as indicated by reports of either load shedding or inability to maintain minimum operating reserve margins in other control areas in the WSCC). The high price bid by out-of-state suppliers as well as the high prices quoted to ISO's out of market calls are indications of market power of out-of-state suppliers.

The divestiture of generation resources by IOUs has resulted in a market share of approximately 9% for a few of the large non-utility generation companies. These companies are net sellers who can profit from causing price spikes. While for most hours of the market, the CA ISO market is sufficiently competitive, at high load conditions, a capacity share less than 10% can give several suppliers a pivotal position. This implies that at high load conditions, even suppliers with less than 9% market share can have significant market power. When net demand for capacity in the ISO control area is more than 91% of available capacity, suppliers can easily bid high prices, and know their bids will be accepted and set the market clearing price. Thus we have the long duration of prices at the price cap even when there is not a shortage on the system.

Figure 33. Real Time Energy Bid Curve
Typical Peak Hour, June 26-29



Figures 34–36 provide an additional illustration of the exercise of market power under relatively high load conditions.

- As shown in Figure 34, prices in the Replacement Reserve Market hit the $750 price cap virtually every day between the hours of 10 to 22 from June 13 – 15. Each of these days was marked by very similar load conditions, with peak loads in excess of 40,000 MW and a maximum of about 35,000 MW scheduled in the Day Ahead and Hour Ahead markets
- It is important to note that units providing Replacement Reserve still receive the real time energy price in addition to this Replacement Reserve capacity payment when called to provide real time energy. Virtually all Replacement Reserve purchased by the ISO is needed to meet real time demand under high load conditions, so that the direct and indirect opportunity cost of providing Replacement Reserve is likely to be minimal for most suppliers.
- Although price spikes and large quantities of Replacement Reserve purchases on June 13 attracted additional supply into this market, prices continued to clear at $750 on June 14 and 15. As shown in Figures 36 and 37, approximately 1,000 MW of additional supply from imports and an additional 1,000 MW of supply from non-utility owned units in the ISO control area entered the market during this period. However, while additional supply from suppliers outside the ISO control area bid as more aggressive price takers, a significantly higher portion supply offered by non-utility supplies within the control area was bid at or near the $750 price cap.
- Despite the continuation of this bidding pattern, prices dropped on June 16 as loads fell well below 40,00 MW, causing a dramatic decrease in quantity of replacement Reserve purchased by the ISO.

Figure 34. Replacement Reserve Bid Prices
Total Supply in Day Ahead Market (Hours 10-22 Only)

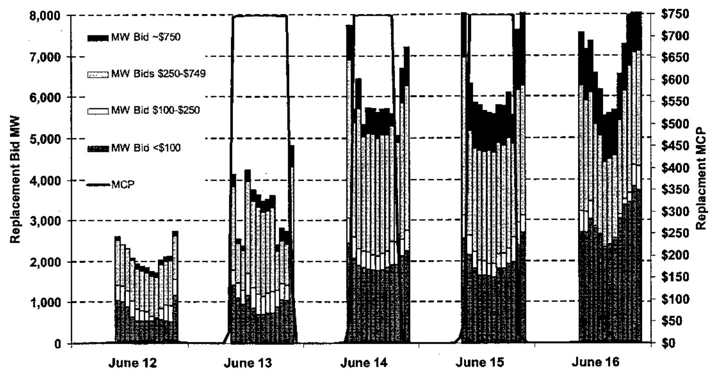


Figure 35. Replacement Reserve Bid Prices
Total Supply in Day Ahead Market

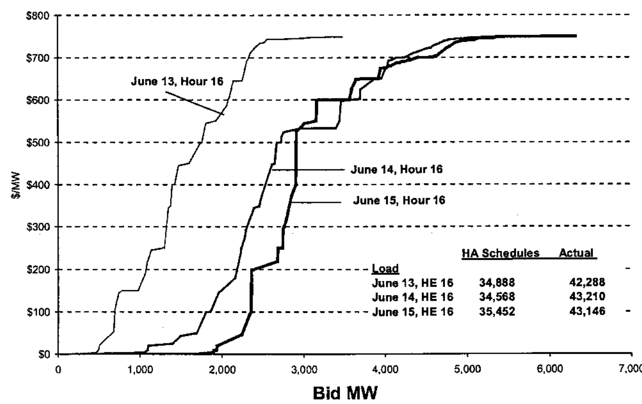


Figure 36. Replacement Reserve Bid Prices (Day Ahead Market)
Non-Utility Generation, Within ISO Control Area (Hours 10-22 Only)

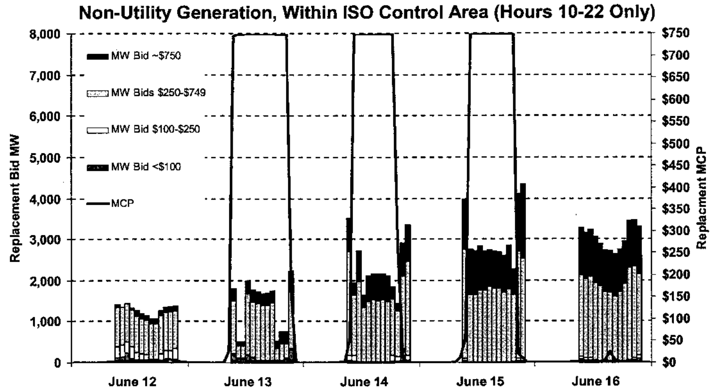
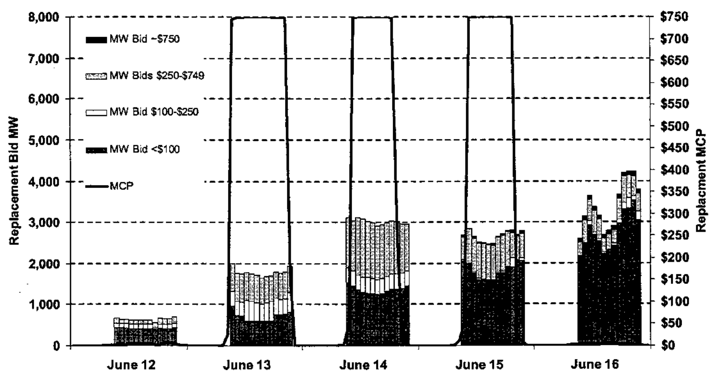


Figure 37. Replacement Reserve Bid Prices (Day Ahead Market)
Imports from Outside ISO Control Area (Hours 10-22 Only)



There are a number of potential mitigation measures that can be implemented to reduce the impact of this exercise of market power. All of the East Coast ISOs have implemented market power mitigation measures to deal with these circumstances. The basic feature of these approaches is to specify conditions under which generators' bids will be re-set to previously agreed upon cost-based levels or average prices during periods which the generator's bids were deemed reasonable. The Department of Market Analysis is exploring the feasibility of implementing these and other market power mitigation options within the California market design.

Committee on Governmental Affairs
EXHIBIT #A-61

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FEDERAL ENERGY
REGULATORY COMMISSION

October 20, 2000

The Honorable David B. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Room 1A
Washington, D.C. 20426

Re: *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange*, Docket No. EL00-95-~~000~~, and -003 *Investigation of Practices of the California Independent System Operator and the California Power Exchange*, Docket No. EL00-98-~~000~~ -003

Dear Secretary Boergers:

By this submission, the California Independent System Operator Corporation ("ISO")[1] is tendering the specifics of a proposed Offer of Settlement addressed to a core issue in the pending dockets – the need to have in place as soon as is practicable a system-wide market power mitigation regime. This submission is not intended to displace the important Congestion Management and market redesign efforts that now are nearing completion. Rather, it is complementary to those initiatives and addressed to issues that 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.

[1] Capitalized terms are used as defined in Appendix A of the ISO Tariff.

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The proposal is submitted as a statement of principles and in settlement format, both so that it may serve as a vehicle for constructive interchange among interested participants and so that it may result in corrective action on a schedule that is consistent with the gravity of the underlying problems. Because it is submitted in response to litigation already initiated, and for the sole purpose of providing a platform for the development of a consensual resolution, ISO management has not submitted the proposal to its Governing Board for its consideration.

Shortly before the filing of this submission, the ISO became aware of the Order issued by the Commission on October 19th. The Commission's order calls for a special meeting on November 1, 2000, a three-week comment period, and a public conference on November 9, 2000. The Commission indicates that it anticipates issuing an order adopting and directing remedies by December 31, 2000. The ISO believes that the procedural format laid out in this proposal can accommodate the Commission's procedural order and proposed schedule.

To facilitate achievement of an expedited consensual resolution, the ISO urges the immediate appointment of a Settlement Judge under direction to convene a technical conference after the Commission's November 1, 2000 meeting and before the public conference on November 9, 2000. Having corrective action in place at the earliest date practicable can best be achieved through a consensual resolution among all affected participants. The ISO urges that the parties to these proceedings be directed to appear at that conference, accompanied by a principal empowered to make commitments, and that each be required to indicate its acceptance of the settlement principles or, failing that, its specific objections to any of its provisions together with suggested modifications that would be acceptable. If a consensual resolution is achieved, it would be the focus of the public conference on the November 9, 2000. If a resolution is not achieved, the settlement effort will nonetheless assist in the public discussion that takes place on November 9, 2000. The ISO agrees with the need for a Commission order to be issued before the end of the calendar year, so that the ISO will be able to have the relief in place by the Spring of 2001.

California's restructured electric power market unquestionably is experiencing severe difficulties, difficulties that largely were camouflaged while retail consumers were insulated from wholesale price spikes. But with the temporary lifting of price caps in the service territory of San Diego Gas & Electric Company, the gravity of the problems has become apparent and has provoked an outcry from all quarters. Understandably, this Commission initiated both a broad investigation of power markets generally and a more specific expedited investigation of the California markets. Equally understandably, constituent groups have filed a series of complaints bringing to the fore more specific grievances and proposed solutions.

The Honorable David B. Boergers
October 20, 2000
Page 3

It perhaps also is understandable that much of the criticism has been focused on the markets administered by the ISO. The ISO's markets are, after all, visible and, as a result of a distortion of the intended market design, have been called upon to discharge responsibilities that never were intended to fall to the ISO. This is said not as a matter of exculpation, but as a fact.

The principal responsibility of the ISO, a responsibility that it has discharged admirably under exceedingly trying circumstances this past summer, is to keep the lights on and to operate the ISO Controlled Grid and its Interconnections with neighboring Control Areas reliably. This was accomplished notwithstanding the failure of Supply indigenous to California to keep pace with Load growth (for much of the decade preceding restructuring, infrastructure investment in Generation and transmission largely was ignored) and notwithstanding the diminished availability of imports to a State that historically has been import dependent.

When the California model was developed, it was recognized that the ISO, to meet its reliability responsibilities, would have to operate, in real-time, an Imbalance Energy market. However, it was always assumed (and intended) that no more than 5%, at the very outside, of the Load within the Control Area would be satisfied in that market. It was intended to be a fine-tuning mechanism, meeting Load that could not reasonably have been forecast in time to be balanced with Supply in a forward market.

In sharp contrast to the intended market design, the ISO real-time imbalance market regularly has been called upon to satisfy 20% of actual Load and on occasion as much as 30% or more. This is intolerable from both a reliability and cost standpoint. This shift of responsibility has placed an enormous added burden on the ISO's Operations staff.[2] Even though the challenges have been of unprecedented proportions, they were and are being met successfully. However, an inevitable consequence of this shift in Load-satisfying responsibility from the Power Exchange ("PX") and bilateral forward markets to the ISO's Real Time Market, apart from testing reliability in the extreme, was to focus attention on the wholesale prices that emerged when Supply had to be accepted because Demand (and the ISO) lacked the ability to say "no."

It is, quite frankly, tempting to provoke an analysis of where responsibility for current difficulties properly should be assigned. That, however, would not be productive. Nor, we submit, would it be productive to call for a reversal of restructuring. It was the failure of the regulatory paradigm to bring forth sufficient, reasonably priced Generation that was a principal impetus for restructuring. During the prior decade, virtually nothing was done to

[2] The ISO recognizes that its own policies may have contributed to underscheduling, and it already has taken corrective action. However, much more needs to be done.

supplement California's aged Supply inventory; in the few years since, independent Generators have proposed approximately 40 new, efficient, and environmentally-preferential projects, requiring an investment of over $10 billion.

Instead of focusing on the assignment of blame, it is imperative that we reach agreement on the underlying problems and on their solutions. In the judgment of the ISO, and without in any way diminishing the significance of the need to reevaluate Congestion Management and market design, the core problems are:

- infrastructure insufficiency, both Generation and transmission;
- inadequate Demand-side price responsiveness;
- insufficient forward contracting;
- inadequate forward scheduling; and
- the need for market power mitigation – system-wide and local.

It is important to note that there is widespread agreement on the core problems identified above, including among the FERC, State regulators, and the market monitoring entities of the ISO and the PX (both the internal market analysis units and the external market monitoring committees). In various orders and reports, these entities have acknowledged the need (a) to site and build new generating and new transmission facilities, (b) to address the lack of retail Demand responsiveness, (c) for forward contracting, (d) to reduce the amount of Load being served in the ISO's Real Time Market through more forward scheduling, and (e) for market power mitigation.[3]

The proposal that comprises this submission addresses system-wide market power mitigation and includes provisions regarding forward contracting and forward scheduling. The core problems regarding the investment needed for new generation facilities, new transmission facilities, and retail Demand response (e.g., end-use metering equipment) require significant action by state regulatory bodies as well as actions by the ISO and

[3] See, e.g., *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Power Exchange and California Independent System Operator* 92 FERC ¶ 61,172 at 61,605; August 2, 2000 Report to Governor Gray Davis by the President of the California Public Utilities Commission and the Chairman of Electricity Oversight Board, Executive Summary; September 6, 2000 Report of the ISO's Market Surveillance Committee; and the August 10, 2000 Report of the ISO Department of Market Analysis to the EOB.

others,[4] and are not specifically addressed in this proposal. Preliminarily, however, it may be instructive to summarize the initiatives that the ISO has underway to make the contribution it is able to make to the resolution of these issues.

"Local" market power mitigation is part of the Congestion Management redesign effort, the results of which soon will be considered by the ISO Governing Board and then presented to the Commission. The stimulation of infrastructure development has been a principal focus of the ISO. Each year the ISO technical staff analyzes the improvements that can be made to the backbone transmission system – from major new installations to rather minor, but still helpful, local modifications. To date, over $800 million in new transmission investments have been approved by the ISO as needed, and hundreds of millions of dollars of additional transmission investments are undergoing analysis.

On the Generation side, the ISO has, where appropriate, utilized its contracting authority to support new Supply additions. And, in response to the "needle" peak issue that complicates significantly California's Supply situation (Load typically is below 35,000 MW but can spike to as high as 44,000 MW for a few hours on relatively few days), the ISO has issued a Request for Bids soliciting incremental peaking resources. The primary objective of this measure is to assure the availability of critical peaking resources; resources necessary to maintain reliable operation of the system. The objective is to assure availability of critical peaking resources, but under a pricing regime that allows adequate compensation for those high cost units without distorting the Market Clearing Price that should pertain in a competitive baseload market. The bifurcation of the capacity required to address peak Demands from the majority of hours of the year in which the market is competitive is a practical recognition that, at least for the immediate future, there may not be a competitive market for peak needs absent significant participation by wholesale and retail Demand. The ISO, therefore, is endeavoring to obtain peaking resources through an alternative competitive regime. The success of this measure in addressing these non-competitive circumstances will ultimately depend on the amount of peaking resources the ISO is able to procure. The ISO's Demand Relief programs also can make a significant contribution to peak management. Accordingly, the ISO again intends to issue a Request for Demand Relief proposals in time to assure the availability of those tools for the Spring and Summer of 2001.

These peak management resources – both Supply enhancement and Demand reduction – are being acquired competitively, but under a pricing mechanism that will not impact Market Clearing Prices in the markets traditionally administered by the PX and the

[4] For example, State regulators must approve the siting, the construction, and the environmental review of new Generation and transmission facilities. The ISO, in consultation with State regulators and Market Participants, must develop and implement policies concerning Interconnection and long-term grid planning matters.

ISO. Peaking units that can and should run only a few hundred hours a year must be assured of the opportunity to achieve full cost recovery over those limited operating hours. If required to obtain that recovery in the traditional second-auction markets, clearing prices would be driven far above the competitive prices to be expected from non-peaking units. By establishing a differentiated pricing regime for peaking resources, the goals of assuring those units a fair opportunity of cost recovery, while insulating the traditional markets from inappropriate upward price pressure, can be realized. While peaking capacity and the ISO's Demand Relief programs are important elements in managing peak Demands, fully competitive retail markets require retail Demand that is able effectively to respond to price signals. The development of technical standards for, and the investment in, metering capability must be addressed in order to have effective Demand response by retail customers.

Finally, the ISO has been endeavoring to stimulate forward contracting and to encourage forward scheduling. As to the latter, tariff changes already have been adopted and more are under consideration. As to the former, the ISO has begun both to explore long-term Supply availability and, because it firmly is of the view that its market intervention should be minimized and that forward contracting more properly is the responsibility of load-serving entities, it has called upon the California Public Utilities Commission to empower and encourage utility distribution companies to forward contract.

These efforts must and will continue. But parallel action to protect against the potential for the system-wide exercise of market power – that is, market power that is not the result of a locational advantage – must be put in place as soon as is practicable. The ISO intends, by this submission, to facilitate achievement of that goal, hopefully through a consensual process. The proposal that is outlined in the enclosed Offer of Settlement and summarized below was designed as a comprehensive, implementable package. It is not presented, however, as a *fait accompli* but, rather, as a basis for considered deliberations. If the parties have suggestions for refinements or even for modifications, the ISO is prepared to explore them fully. What the ISO seeks to avoid is the squandering of time, prejudicing the pursuit, if necessary, of more action-forcing steps. The time-imperative does not permit anything short of the full commitment of all affected constituencies. That is why we call for the immediate appointment of a Settlement Judge and for direction from the Commission that all parties be required, expeditiously, to respond with specificity.

The proposal that is attached is bottomed on the analyses undertaken independently by the Market Surveillance Committee and the Department of Market Analysis ("DMA"), each of which indicates that, while the markets are competitive for many hours of the year, market power is evident when available Supply is only moderately sufficient to meet Demand. *See* the attached Declaration of Dr. Eric Hildebrandt. In response to these analyses, the ISO initially endeavored to develop a process that would allow for the bifurcation of the market between "competitive" and "non-competitive" hours. However, bifurcation of the markets in this fashion would present issues of practicality and predictability. Accordingly, while willing to discuss any and all options in settlement negotiations (including bifurcation of markets into competitive and non-competitive periods), the ISO is proposing a simpler approach. Namely, the ISO proposes that the price cap be established at $100/Mwhr with the following exemptions:[5] (1) if an owner demonstrates that a payment of $100/Mwhr 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 be exempt; (3) owners and operators whose units do not exceed 50 MW would be exempt; (4) incremental Generation (additions to existing units and new units) would be exempt; (5) any owner or marketer who demonstrates that it has committed 70% 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.[6] Exempt units would be subject to whatever higher damage-control price cap is in place.[7] It is the ISO's expectation that the combined effect of the $100/Mwhr price cap with the availability of an exemption from that limitation will incline those that own or control Generation resources to forward contract.

As a corollary measure, it is proposed that Load be required to forward contract for no less than 85% 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% requirement. Finally, while forward contracting should go a long way toward resolution of the underscheduling problem, Scheduling Coordinators would be required to schedule no less than 90% of Load in the Day-Ahead Market and no less than 95% 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

[5]A price cap ceiling of $100/Mwhr was selected because the analysis undertaken by the DMA indicates that during times when the market is workably competitive, it clears at prices below $100/Mwhr. *See* Hildebrandt Declaration at 3,7,9. The ISO would propose to peg that ceiling price to an assumed monthly average burner tip price of natural gas at $7/MMBtu. To the extent that the price of natural gas deviates from this assumed cost by more than a threshold level, say 5%, it would be the ISO's intention that the ceiling price be adjusted to reflect that cost change. Application of that standard today might require a price higher than $100/Mwhr in light of recent escalations in natural gas prices. It is proposed that the base price be established by reference to the most current natural gas information available at the time that the Commission approves the settlement.

[6]Imports present an especially vexing problem. A suggested solution is offered but on this issue in particular, we encourage the parties to engage in frank discussions toward the end of developing a satisfactory compromise.

[7] Demand-side programs would not be subject to any payment cap.

The Honorable David B. Boergers
October 20, 2000
Page 8

submitted, respectively, in the Day-Ahead and Hour-Ahead Markets, and out-of-market costs would be charged to underscheduled Load and to Generation appearing in real-time in excess of balanced schedules.

By requiring forward contracting to the extent proposed, Utility Distribution Companies, with the concurrence of the Public Utilities Commission, should be in a position to secure for their customers with the most inelastic Loads – residential and small commercial – adequate supplies at fixed rates. The ISO urges the participation of the Public Utilities Commission in this settlement effort so that the objective of consumer protection may best be realized.

The ISO does not presume that its proposal is free of difficulties for either Generators or marketers or for Load-serving entities. The ISO does urge, however, that interested parties resist the inclination to dwell on shortcomings, on the inclination to be critical. If the proposal were being offered as a final resolution, criticism might be appropriate. It is offered, instead, as a good faith basis for beginning a dialogue that no longer can be postponed. Development of an acceptable solution will require the cooperation of the ISO, of Market Participants, of Load-serving entities and their consumers, and of regulators. That is precisely what is so desperately needed at this critical juncture – cooperation and the cessation of finger-pointing. Nothing less is tolerable; nothing less will discharge the responsibility which each bears to ensure that restructuring works for the consumers who are to be its principal beneficiaries.

Copies of this submission are being served on all parties to these consolidated proceedings and Docket Nos. Docket Nos. EL00-104-000, EL01-1-000, EL01-2-000 and ER00-3673.

Sincerely,
Ed Berlin (MSC)
Edward Berlin

Attachments: Offer of Settlement
Declaration of Dr. Eric Hildebrandt, Ph.D.

cc: All Parties

The Honorable James J. Hoecker
The Honorable Linda K. Breathitt
The Honorable Curtis L. Hèbert, Jr.
The Honorable William L. Massey
Chairman Michael A. Kahn
California Electricity Oversight Board
President Loretta Lynch
California Public Utility Commission

OFFER OF SETTLEMENT

Guiding Principles

I. Protection of Consumers from the Exercise of Market Power

There is evidence that at times of supply insufficiency, California's electricity markets are not workably competitive. As a consequence, load-serving entities, and in one case its consumers, have been subjected to unacceptably high prices. To provide consumers with protection from the exercise of market power, while providing supply with the incentive both to enter California's markets and to forward contract with load-serving entities on terms that are fair to both, it is proposed that:

(a) the payment price cap that applies in the markets administered by the ISO be reduced to $100/Mwhr;

(b) that resources bidding into those markets be paid the market clearing price ("MCP"), but not in excess of $100/Mwhr. Bids submitted in excess of the $100/Mwhr payment cap would be rejected, unless they were submitted by an "exempt" entity, in which case the bidder would be paid the MCP not in excess of any prevailing damage-control cap (currently set at $250/Mwhr);

(c) the Owner of a supply resource or supply portfolio (including commitments for demand reductions) could receive partial or complete exemption from the $100/Mwhr payment price limitation:

(1) if it demonstrates that the $100/Mwhr price is insufficient to recover a unit's avoided operating costs (the costs that would not be incurred if the unit did not operate) and make a contribution to fixed cost recovery. In that event, the unit would be paid a price sufficient to recover those costs and to make that contribution, but that price will neither establish the MCP paid to the Owner for other resources within its portfolio nor the MCP paid to others;

(2) for generation that is powered by renewable resources (e.g., wind, solar);

(3) for a generation resource of 50 MW or less, providing that the Owner or operator of such resource neither owns nor operates a generating unit with a nameplate capacity in excess of 50 MW;

(4) for incremental supply resources, either additions to existing units or the development of new units, located within the State of California;

(5) for the remainder of a supply portfolio, if it is demonstrated that at least 70% of the portfolio is contractually committed to load-serving entities within California for a term extending at least through October 15, 2002; and

(6) for imports from out-of-State resources but only to the extent that the imports exceed exports made by the Owner of the supply or by any directly- or indirectly-affiliated entity.

(d) demand-side programs would not be subject to any payment cap, but could be compensated at a price that is acceptable to the Governing Board.

II. Forward Contracting by Load

It is a common attribute of commodity markets that those who must have access to supply – and therefore have requirements that are relatively inelastic – will hedge against exposure to spot price volatility by forward contracting for a significant portion of their requirements. The load-serving entities in California must be empowered to achieve this customary level of price protection and they must in fact exercise that authority. Therefore, it is proposed:

(a) that load-serving entities commit to forward contracting for no less than 85% of their anticipated requirements, at least through October 15, 2002. In calculating satisfaction of this commitment, load-serving entities would include capacity that they currently own; and

(b) that the California Public Utilities Commission empower the Utility Distribution Companies to forward contract at least to that extent.

III. Forward Scheduling For Load

It is intolerable for the imbalance energy market to be the vehicle for the satisfaction of load that could and should have been anticipated and met in the forward markets. Forward contracting should help alleviate this problem and enable Scheduling Coordinators to adhere to a requirement to submit balanced schedules covering at least 90% of load in the Day-Ahead market, and 95% of load in the Hour-Ahead market. To ensure compliance with this requirement, it is proposed that:

(a) a real-time charge (Large Uninstructed Deviation Charge) be assessed against load and generation that appears in real-time and exceeds 1.10 and 1.05 times the balanced schedules submitted, respectively, in the Day-Ahead and Hour-Ahead markets; and

(b) the ISO also proposes that a Real-time Trading Charge, initially set at zero, apply to all instructed deviations (both generation and load) that occur in real time. The purpose of this charge is to create a financial preference for all parties to trade in the forward markets; and

(c) Out-of-Market costs will be charged to underscheduled load and to generation appearing in real-time in excess of balanced schedules.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. All Sellers of Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.	)	Docket No. EL00-95-000
Investigation of Practices of the California Independent System Operator Corporation and the California Power Exchange	)	Docket No. EL00-98-000

DECLARATION OF ERIC HILDEBRANDT

1. My name is Eric Hildebrandt. My address is 151 Blue Ravine Road, Folsom, California 95630. I am employed by the California Independent System Operator Corporation ("the ISO") as Manager of Market Monitoring in the Department of Market Analysis (DMA).

I have specialized in economic analysis and market research relating to energy issues for over ten years, with emphasis on research, planning and evaluation studies for the electric utility industry. Since joining the ISO over two years ago, I have worked extensively on analysis of the overall performance and competitiveness of California's energy and Ancillary Services markets, analysis and mitigation of local market power through Reliability Must-Run (RMR) Contracts, and, most recently, on developing and analyzing system market power mitigation options. I am a primary author of a recent DMA report on California's market performance (*California Energy Market Issues and Performance: May-June, 2000*, Special Report by ISO DMA, August 10, 2000).

2. I began my career in energy research at the Center for Energy and Environment at the University of Pennsylvania, and then worked for over six years as an economic consultant to the electric utility industry. Prior to joining the ISO, I worked for over three years at the Sacramento Municipal Utility District as Supervisor of Monitoring and Evaluation. I have published numerous articles on energy issues in professional journals and have frequently presented my research in academic and industry forums. I hold a B.S. degree in Economics from the Colorado College, and an M.S. and a Ph.D. in Energy Management and Policy from the University of Pennsylvania.

3. I provide this declaration in support of the proposed Offer of Settlement being submitted by the California ISO in the above captioned proceedings.

4. The performance of the ISO markets over the past two years has shown that during most hours of the year supply conditions has been sufficient to ensure workable competition among suppliers and that such competition leads to prices closely aligned with the costs of supply required to meet demand. Analysis by the DMA shows that when significant supply exists (e.g., when total available supply reaches or exceeds 120% of system demand for energy and ancillary

services), prices tend to be close to the variable operating cost of the highest-cost generating unit required to meet demand. However, during high load hours and hours of limited supply, the combination of tight supply conditions and the limited ability of consumers to reduce consumption in response to prices creates the situation in which the markets are less than workably competitive.

5. The persistently high prices observed in California's wholesale energy markets since late May during periods when no absolute scarcity of supply exists provide a strong indication of lack of competitiveness over this period. While only a few peaking units have had estimated operating costs of $100/MWh, the combined hourly average wholesale cost of energy in the PX/ISO markets has exceeded $100/MWh of load served more than 1,200 hours or over 14% of total hours over this period on an annualized basis. In contrast, the average wholesale cost of energy in the PX/ISO markets exceeded $100/MWh during only 1% to 2% of hours during both the ISO's first two years of operation.

6. The DMA has also performed more systematic, quantitative analyses of market competitiveness and any potential scarcity of supply within the ISO system over the ISO's first two and one half years by comparing the difference between the actual wholesale price of energy in the ISO system and an estimate of baseline costs that would be incurred under competitive market conditions. The competitive baseline price used in this analysis represents the estimated variable operating cost of the marginal thermal generation unit within the ISO system needed to meet system demand each hour, after taking into account the actual supply of imports and other supply resources within the ISO control area. The

degree to which actual wholesale energy costs (including load met in the PX Day Ahead market and the ISO real time market) exceed this competitive baseline cost (expressed as a percentage of actual whole prices) represents the *price-cost markup.*

The methodology used to determine this competitive market baseline and price-cost mark-up can be briefly described as follows. First, the operating cost major thermal units within the ISO system are estimated based on unit heat rates, spot market gas prices, and estimates of other O&M costs. Second, the availability of each of these units is determined for each operating day based on metering, scheduling and bid data. Third, a thermal supply curve is developed by ranking units based on price, and summing up the capacity available at each price level. In the base case of our analysis, we also include in this "supply curve" real time energy bids from imports (submitted as Replacement Reserve and Supplemental Energy bids). Fourth, the net demand that must be met by these sources of supply is calculated by subtracting the actual output from all other sources of energy (including upward regulation) from the total system demand for energy (plus upward regulation).

In effect, this approach "nets out" from system demand all sources of supply other than the major thermal units within ISO system and real time energy from imports, and then calculates the marginal cost of meeting the remaining net demand based on the cost of the remaining supply of major thermal units and bid price of real time energy bids. Since the actual or opportunity cost of imports cannot be easily determined, we include real time energy bids "as bid" in this analysis in order to provide a conservative estimate of the degree to which wholesale prices exceed competitive levels.

In order to assess the degree to which high wholesale prices may be attributable to absolute scarcity of supply, we also identify the portion of the price-cost markup occurring during hours of potential resource scarcity. In this analysis, scarcity is defined based on hours when total available supply in the ISO system (including import bids and out-of-market purchases) is less than total system demand for energy plus 10% ancillary services (representing about 3% upward regulation, and 7% operating reserve). Additional details of the methodology and results of our analysis of scarcity were presented in a previous DMA report (*Report on California Energy Market Issues and Performance: May-June, 2000*, Special Report by ISO DMA, August 10, 2000).

Exhibit 1 presents result of this analysis of overall competitiveness of California's wholesale energy markets based on the markup of prices above costs. As shown in Exhibit 1, wholesale costs exceeded this competitive baseline by only 1% during the first year of operation and only 6% during the second year of operation. However, due to the very high price-cost markup since May of this year, wholesale costs have exceeded this competitive baseline by 39% on an annualized basis over this period. While a significant portion of the increase in wholesale costs above this competitive baseline have been incurred during hours of potential absolute resource scarcity, the bulk of these additional costs are attributable a lack of competition, rather than scarcity. In addition, prices continued to significantly exceed competitive levels even after the ISO's real time

Exhibit 1. Analysis of Impact of Non-Competitive Markets on Wholesale Energy Prices

Period	Avg. Wholesale Cost ($/MW) [1] A	Competitive Baseline Costs($/MW) B	Avg. Price-cost Markup ($/MW) (A – B)	Markup during Hours of Potential Scarcity [2]	Markup during Hours of No Potential Scarcity	Markup as Percent of Total Wholesale Cost [3]
Apr-98	$23	$27	-$3	$0	-$3	-12%
May-98	$13	$11	$1	$0	$1	14%
Jun-98	$14	$20	-$6	$0	-$6	-37%
Jul-98	$36	$30	$6	$0	$6	18%
Aug-98	$43	$34	$10	$0	$10	29%
Sep-98	$38	$29	$10	$1	$9	22%
Oct-98	$27	$29	-$2	$0	-$2	-6%
Nov-98	$26	$30	-$4	$0	-$4	-13%
Dec-98	$30	$30	-$1	$0	-$1	0%
Jan-99	$22	$25	-$3	$0	-$3	-12%
Feb-99	$20	$24	-$4	$0	-$4	-17%
Mar-99	$20	$24	-$3	$0	-$3	-15%
Apr-99	$25	$26	-$1	$0	-$1	-3%
May-99	$25	$24	$2	$0	$2	8%
Jun-99	$27	$27	$0	$0	$0	-1%
Jul-99	$35	$29	$6	$1	$5	17%
Aug-99	$38	$33	$5	$1	$4	9%
Sep-99	$36	$33	$3	$0	$3	10%
Oct-99	$50	$38	$12	$0	$12	26%
Nov-99	$35	$32	$4	$0	$4	12%
Dec-99	$30	$30	$0	$0	$0	0%
Jan-00	$32	$30	$2	$0	$2	6%
Feb-00	$30	$32	-$2	$0	-$2	-6%
Mar-00	$30	$33	-$3	$0	-$3	-10%
Apr-00	$31	$31	$0	$0	$0	0%
May-00	$58	$46	$12	$1	$11	22%
Jun-00	$147	$54	$93	$26	$67	67%
Jul-00	$112	$54	$58	$14	$44	56%
Aug-00	$167	$64	$104	$28	$76	67%
Sep-00	$119	$70	$49	$9	$39	45%
Apr 1998-Mar 1999	$27	$26	$0	$0	$1	1%
Apr 1999-Mar 2000	$33	$31	$2	$0	$2	6%
Oct 1999-Sep 2000	$74	$44	$30	$7	$23	39%

[1] Avg Wholesale Cost = [Hour Ahead $Schedule_{NP15}$ x PX MCP $_{NP15}$] + [Hour Ahead $Schedule_{SP5}$ x $PXMCP_{SP15}$] + [(System Load Hour $_{NP15}$ - Ahead $Schedule_{NP15)}$ x Real Time MCP $_{NP15}$] + [(System Load Hour $_{SP15}$ - Ahead $Schedule_{SP15)}$ x Real Time MCP $_{SP15}$],

where zonal schedules and loads are estimated based on Utility Distribution Company (UDC) area schedules and generation (with NP15 prices applied to PG&E area and SP15 prices applied to SCE and SDG&E service areas).

[2] Hours of potential scarcity defined as hours when market supply of capacity was less than total system energy demand plus 10% ancillary services (3% upward regulation, plus 7% operating reserve).

[3] Overall Price-Cost Markup = (Actual Wholesale Costs - Baseline Costs) / Baseline Costs, with hourly costs weighted by total system loads minus generation owned or under contract to UDCs (utility-owned generation, QFs, etc.)

price cap was lowered to $250 in August.

7. Both the methodology and results of the analysis summarized in Exhibit 1 are similar to analysis performed by the Chairman of the ISO's Market Surveillance Committee (MSC) in conjunction with researchers at the University of California Energy Institute (Borenstein, Severin; Bushnell, James; and Wolak, Frank, "Diagnosing Market Power in California's Restructured Electricity Markets", August 2000; Updated results through June 2000 presented in *An Analysis of the June 200 Price Spikes in the California ISO's Energy and Ancillary Service Markets*, MSC Report, September 6, 2000). Although conducted independently and with somewhat different assumptions, both of these studies reach essentially the same conclusion with respect to the significant increase in the degree to which the markets are not workably competitive since late May of this year.

8. The fundamental solution to increased competition is create ways for consumers to respond to increasing prices, accelerate entry to the market by new suppliers, and provide consumers the ability to avoid or hedge against the financial impacts of periods when workable competition is lacking through long term contracts. The DMA is examining the appropriate structural market changes to achieve these objectives, and will continue to present its analyses to the ISO Board to assist in the development of needed market reforms. However, needed structural market changes or developments are likely to require at least two years to be implemented to a degree that will ensure a workably competitive market. In the interim, mitigation of insufficient competition and its financial impact on consumers (and load serving entities that may be obligated to serve customers at

limited prices) is necessary to allow continued development of deregulated energy markets, rather than either a retreat to cost-based regulation.

The settlement agreement being proposed by the ISO at this time provides a framework for balancing the goal of protecting against the financial impacts of periods of insufficient competition over the short-term, with the need to accelerate the development of key structural changes necessary to ensure an efficient, equitable deregulated energy market over the longer term. Specifically, the proposed approach is designed to allow the bulk of wholesale energy costs (i.e. 80 to 90%) to be met at a lower, more reasonable and less volatile price, while allowing the remaining 10% to 20% to be met through a more robust spot market, which includes both the Day Ahead PX market and the ISO's real time imbalance market. This approach provides protection against the bulk of the financial *impacts* of a lack of competitiveness, without destroying the marginal price signals sent through higher spot market prices in periods of tight supply and demand. Preserving such price signals is essential for fostering development of demand elasticity and accelerating development of new supply.

The preferred outcome of the ISO's proposed settlement is to increase the level of forward contracting between the state's major load serving entities and non-utility generation owners to a level that would ensure that 80% to 90% of total ISO system load is covered through a combination of utility-owned generation and long term contracts with non-utility generation. In addition providing a financial hedge against the bulk of the impacts of insufficiently competitive markets, this would significantly reduce the reliability problems associated with the current level of under-scheduling of loads and generation during periods when competition is lacking. However, in the absence of forward contracting, the proposed approach also provides for an alternative $100/MW payment cap, representing a level that provides significant protection for buyers when competition is lacking, and exceeds the variable cost of virtually all thermal generation with the ISO system. The proposed approach allows for payment beyond the $100 cap for the limited number of units that may demonstrate costs in excess of this level.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. All Sellers of Ancillary Services into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, et al., Respondents.	)	Docket No. EL00-95-000
Investigation of Practices of the California Independent System Operator Corporation and the California Power Exchange	)	Docket No. EL00-98-000

DECLARATION OF ERIC HILDEBRANDT

I, Eric W. Hildebrandt, declare under penalty of perjury that the statements contained in the foregoing Declaration of Eric W. Hildebrandt are true and correct to the best of my knowledge, information, and belief.

Executed on this 19th day of October, 2000.

E Hildebrandt
Eric W. Hildebrandt

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties on the official service lists compiled by the Secretary in the above-captioned proceeding and Docket Nos. EL00-104-000, EL01-1-000, EL01-2-000 and ER00-3673 in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C. this 20th day of October, 2000.

Michael E. Ward

Committee on Governmental Affairs
EXHIBIT #A-62

California Electricity Markets: Issues for Examination

August 17, 2000

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Observed Abuses

Interzonal Congestion Gaming

Intentional Creation of Congestion

On 5/24/99, Enron scheduled 2800 MW on a 15 MW path knowing that all but 15 MW would be cut during the congestion process. This likely results in increased day-ahead energy prices, and increased congestion costs on the path where the game was played. Day-ahead peak energy prices increased from about $30 to about $45/MWh

Reference: ISO Market Operations Report 5/24/99

Fictitious day-ahead schedules counter-flow to congestion

Parties submit schedules flowing counter to congestion to receive congestion payments (these schedules also reduce the cost of congestion). The schedules are not performed in real-time.

Reference: e-mail from ISO dated 7/21/00

Intrazonal Congestion Gaming

INC game

Specific generation in a local area is required to *increase* output to resolve a local reliability problem. When the generation becomes aware it is needed, bids are increased from competitive levels to the cap. In 2000, the cost of the INC game has exceed $30 million.

Reference: ISO FERC filing Docket No. ER00-555-000 dated 11/23/99 "ANSWER OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO MOTIONS TO INTERVENE, COMMENTS, PROTESTS, AND REQUEST FOR HEARING", December 20, 1999 "Opinion of the ISO Department of Market Analysis"

DEC game

Specific generation in a local area is required to *decrease* output to resolve a local reliability problem. When the generation becomes aware of the problem, it is bids negative prices and forces the ISO to pay the cap to reduce output. During the week of June 14, 1999 Duke was able to extract about a $1 million a day as a result of this game.

Reference: ISO Amendment 18, FERC Docket No. ER-99-3301 and ISO FERC Amendment 23 filing Docket No. ER00-555-000 "ANSWER OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO MOTIONS TO INTERVENE, COMMENTS, PROTESTS, AND REQUEST FOR HEARING", December 20, 1999 "Opinion of the ISO Department of Market Analysis"

Scheduled/unscheduled maintenance of Reliability Must Run Units

Units under contract to relieve local reliability problems have simultaneous outages (both scheduled and unscheduled). The ISO must find another unit to resolve the problem; often there is only one owner that solve the problem.

This other unit plays the INC or DEC game and receives payments at the cap.

Out of Market (OOM) changes in bidding behavior

For local reliability reasons, the ISO requires a specific unit that has not bid. The ISO calls the unit and tells it is needed. The unit then bids the cap and forces the ISO to pay it the cap to perform

Reference: ISO FERC filing Docket No. ER00-555-000 dated 11/23/99 "ANSWER OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO MOTIONS TO INTERVENE, COMMENTS, PROTESTS, AND REQUEST FOR HEARING", December 20, 1999 "Opinion of the ISO Department of Market Analysis"

Real-time Energy Market Gaming

Large quantities of supply bid at the cap

Often several thousand of MWs are bid at the cap during moderate to high load conditions.

Reference: ISO DMA report to MSC, July 24, 2000

Gaming of target price

ISO reported that "thousands of MWs of DEC bids" were received on the ties. These bids resulting in an increase in the real-time price.

Reference: ISO document "ISO Target Price Change", 4/4/00 and SCE document "ISO Target Price: Problems with new Methodology".

Removing bids from the BEEP stack when the ISO indicates supplies are tight

When ISO indicates supplies are tight, parties remove bids from the ISO real-time market. This increases likelihood of real-time prices spikes, block OOM purchases (multiple hours) at the cap, increased replacement reserve purchases, and increases the probability of Stage III.

Day-ahead Energy Market Gaming

Supply withholding from the day-ahead market

Market power based bids

Bidding does not reflect the cost of generation

Congestion gaming

Bidding supply into the unconstrained market that will be removed during the congestion process.

Failing to bid supply to create congestion.

MW "laundering"

Exporting MWs outside of the ISO with the intent of selling back into the real-time market - Increases the day-ahead price, increases amount of load served in the real-time market, increases replacement reserve purchases, increases block OOM purchases. Increases likely that the CA ISO will be forced to declare a Stage III emergency during real-time (suppliers can be paid above the cap under these circumstances.)

Ancillary Service Gaming

Market power bidding

Price of Replacement Reserve reached $9999/MWh on July 13, 1998. Price of energy during that time was about $40/MWh. Bidder assumed that software only accepted 4 digits, in reality the software allows 17 digits.

Pricing for reserve capacity much more expensive than price of underlying energy

Partially resolved by changes to ISO market purchasing practices (Rational Buyer)

Double Selling of capacity

Many instances of generators selling ancillary services, then dumping energy out of the capacity. ISO has not implemented "No Pay" to penalize this behavior.

Failure to Perform

ISO has reported that parties selling Regulation down have removed their generation from the ISO's control and produced energy during periods of high prices.

Arenas for Investigation

Energy Markets

Changes in bidding behavior from a unit

- Examine changes in bidding in both quantity and price during
  - Low loads
  - High loads
  - Single zone/ split zones
  - Generation and transmission outages
  - ISO announcements (alerts, warnings, Stage I, Stage II)
- Examine changes in quantities bids at low, medium and high (cap) prices
- Changes in portfolio bidding behavior from an owner
- Examine changes in the total MWs bid into various markets (PX day-ahead, PX day-of, ISO real-time energy, ISO ancillary services)
- Examine changes in quantity of high price bids

Withholding of physical capacity

- Examine duration and timing of scheduled and unscheduled maintenance
- Examine behavior correlated with transmission outages and load conditions

Examine behavior of multiple owners

- Correlation of scheduled and unscheduled outages
- Correlation of bidding behavior between participants
- Selection of market, price and quantity bidding behavior of individual units based on
- ISO 2 day-ahead load forecasts, Real-time load conditions Transmission and generation outages
- Quantity (as percent of total ownership) offered to PX day-ahead
- Percentage of total bids offered at low, medium, high (cap) prices
- Correlation of capacity withdrawn from ISO and PX markets
- Withdrawing bids from ISO real-time markets

Changes in the amount of unscheduled capacity bid into the ISO real-time markets

- Results in increased purchases of Replacement Reserves
- Increases probability of block OOM calls
- Increase probability of Stage III payments above the cap

Bilateral contracts

- Examine the total amount of power parties have obtained via contract
  - Have third parties obtained market power via contract?
- Examine contracts for "parking"

  Power is scheduled out of the ISO in the day-ahead with the intention of selling into the ISO real-time markets. NERC tags contain false information indicating that load outside of the ISO will be served. Parties may do this in an attempt to withhold power from the day-ahead market and avoid detection, try to obtain block OOM calls, try to get Stage III above cap payments

- Transfer of bidding and scheduling rights
    - A single party may control the bidding behavior of multiple parties

Congestion Markets

- Behavior to increase Revenue from Firm Transmission Rights (FTRs)/cost of congestion
- Scheduling practice of FTR holders over paths in which they hold FTRs
- Adjustment bid practices of parties holding FTRs
- Changes in adjustment bids based on system conditions
- Behavior to increase zonal prices
- Scheduling practices
- Frequency and magnitude of schedule changes on particular paths
- Artificial schedules may be submitted to increase the magnitude/frequency of congestion to increase zonal prices

Ancillary Services Markets

- Changes in bidding behavior of both price and quantity offered
- Changes of bidding behavior during low and high load conditions, single zone/split zones
- Quantity bid at high prices
- Correlation of quantity, price bids between suppliers