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

Prepared by the Staff of the
Federal Energy Regulatory Commission

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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

[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.

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**

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.**

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).

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.

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.

- 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.

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 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.

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.

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.

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.

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

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[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.*

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

[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.

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.

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[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.

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.

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 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.

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[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).

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."

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.

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...)

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

[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.

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.

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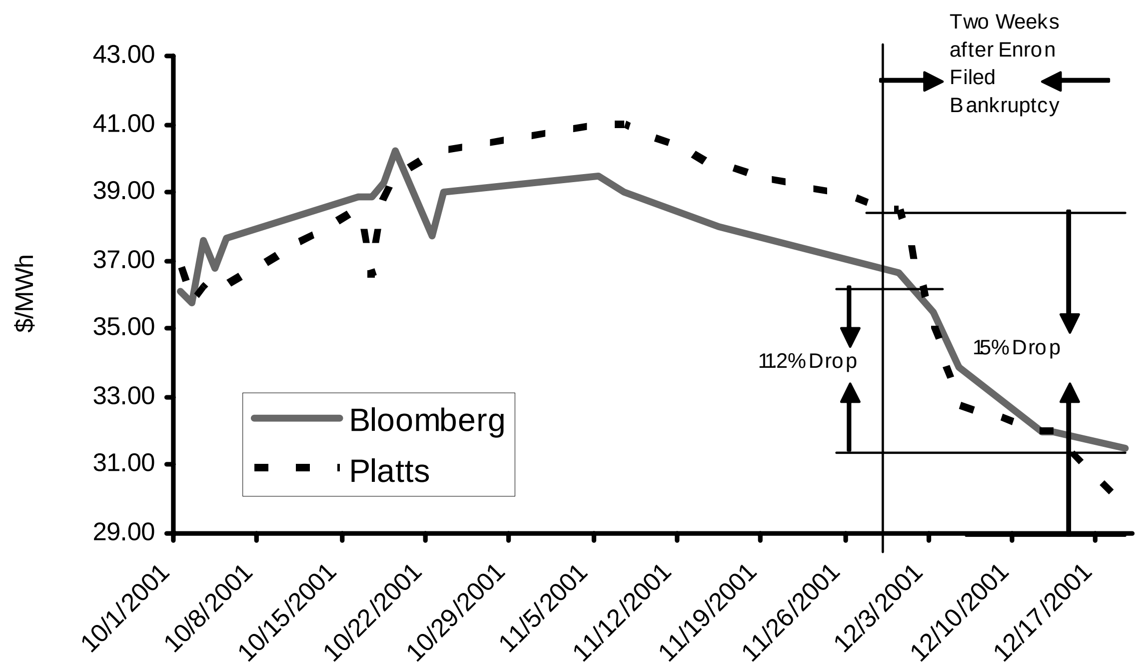
[45] "Western Senators Want to Know if Enron Manipulated the Market," *Power Markets Week*, February 4, 2002.

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.

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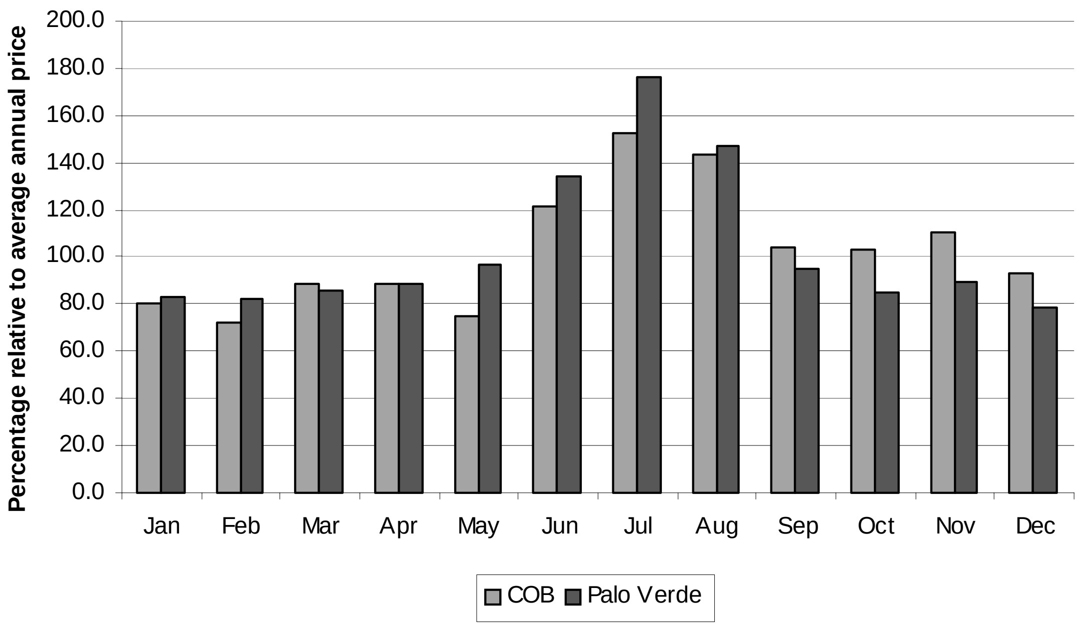
[46]Calculating SFs requires at least four-years of data. Accordingly, Staff used NYMEX futures data for COB and Palo Verde because the NYNEX COB and Palo Verde futures are the only futures or forward markets that have four-year data. Seasonal adjustment "requires at least four full years of data". *See*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

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?

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[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).

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]]

[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).

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).

- 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.

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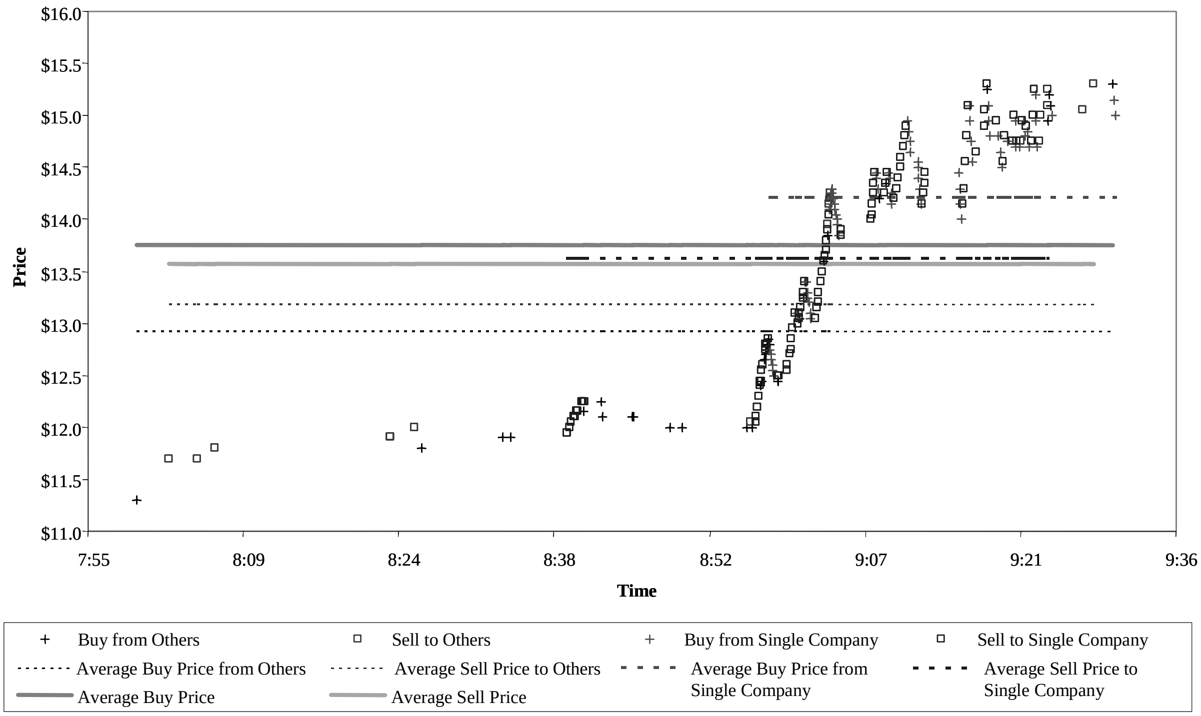
[62] June 4, 2002, response to NGI Data Request under Docket No. PA02-2-000.

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



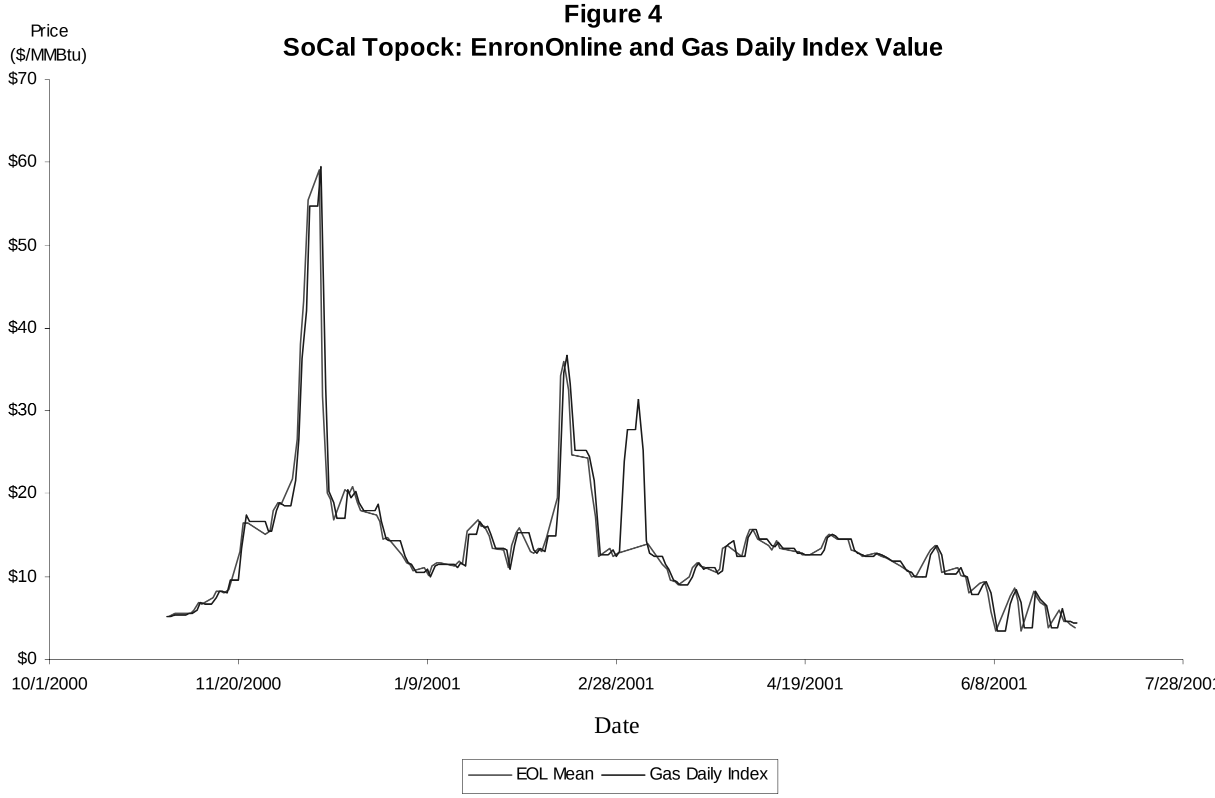
Total trading volume at Southern California Topock reported to *Gas Daily* was 6,766,000 MMBtu, which was the busiest trading point for that day. For February 1 at Topock, based on trades that took place on January 31, *Gas Daily* reported that prices ranged from a low of $11.10/MMBtu to a high of $16.05/MMBtu 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



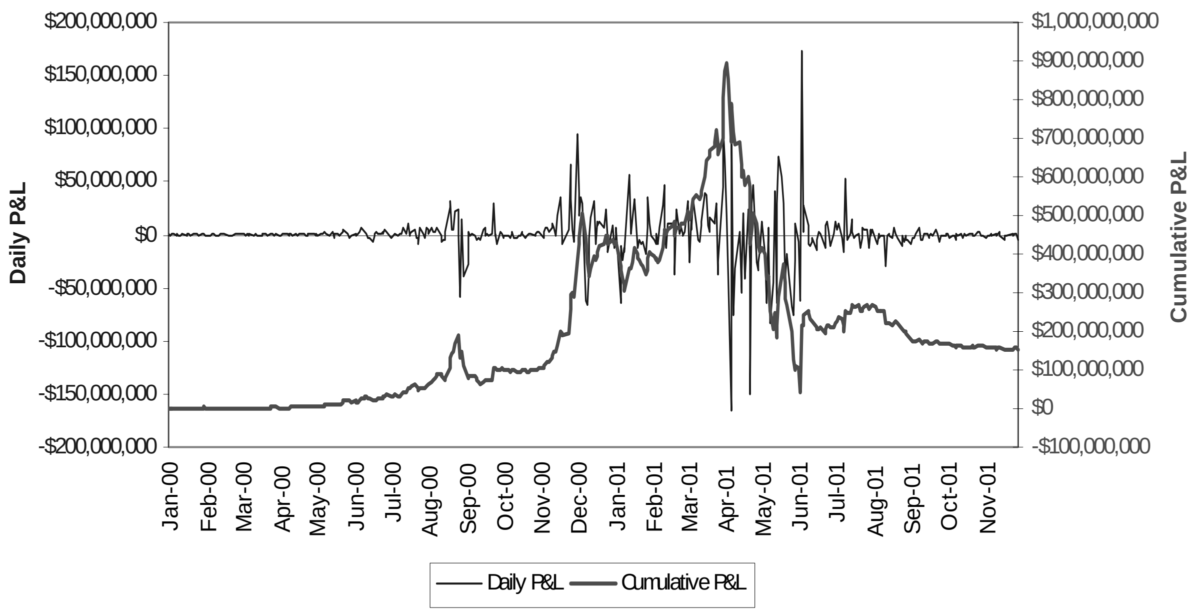
In short, the price data published by the reporting firms would only show a large price movement. No reader would know that a large percentage of that trading activity was between two specific parties, Enron and this single counter party, because the reporting firms would only receive an average price 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.

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 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.

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...)

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.

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.

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.

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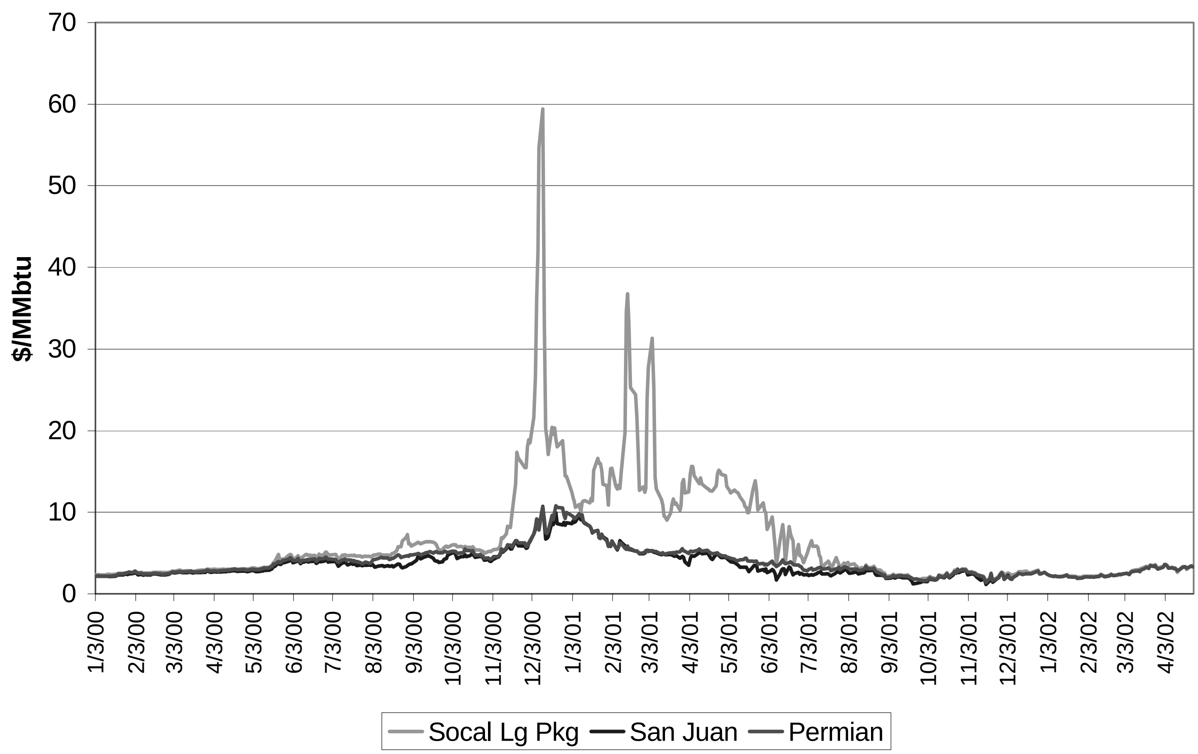
[76] *See* December 18 Order, 97 FERC at 62,171, 62,182, and 62,218; June 19 Order, 95 FERC at 62,558; San Diego Gas & Electric Co., *et al.*, 93 FERC ¶ 61,121 at 61,349-50 (2000); and 93 FERC ¶ 61,294 at 61,999 and 62,011.

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

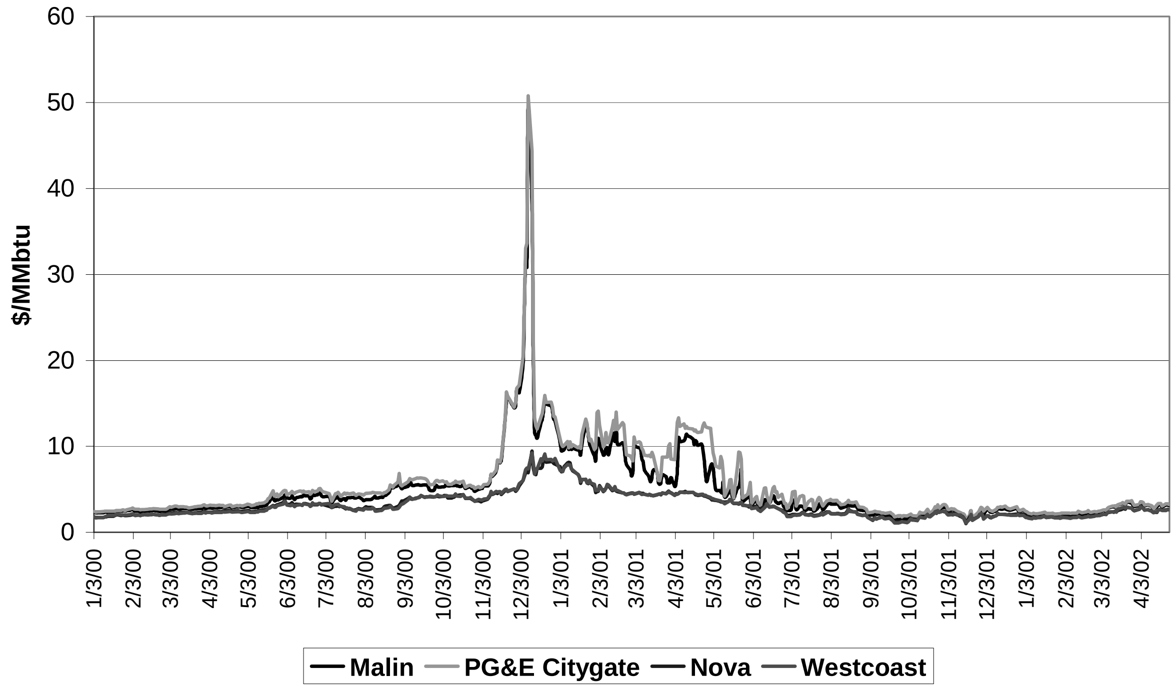


Large Packages) to the San Juan and Permian basin spot prices.

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]),

[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.

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.

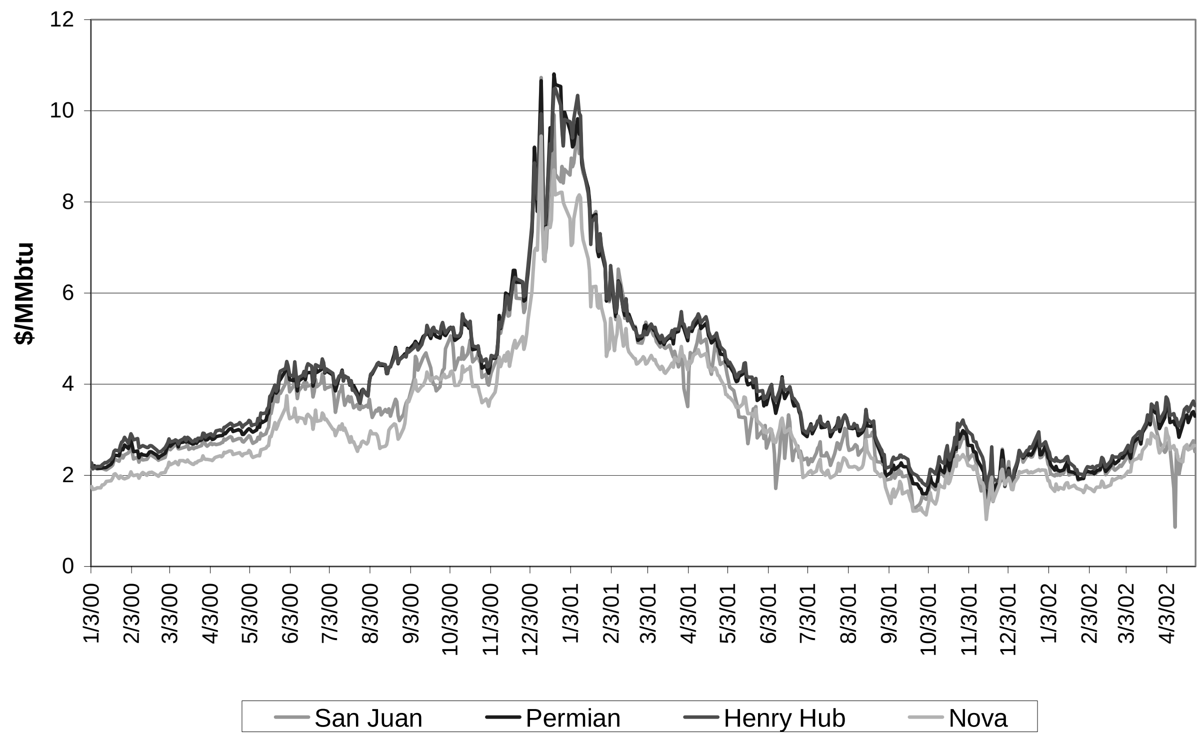
b. Comparison of Producing Area Spot Prices to Henry Hub Spot Prices

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.

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

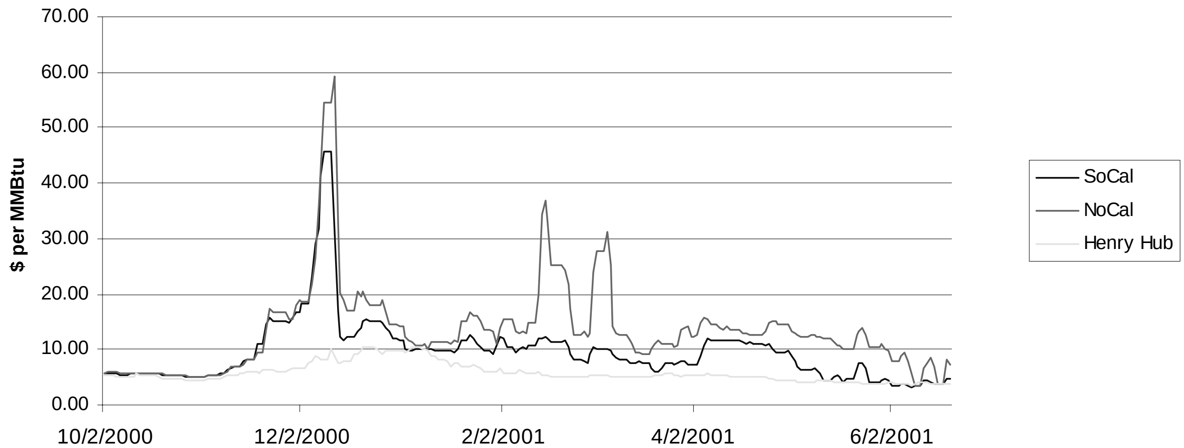
Figure 8: Producing Area Prices vs. Henry Hub



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 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

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[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...)

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.

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.

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.

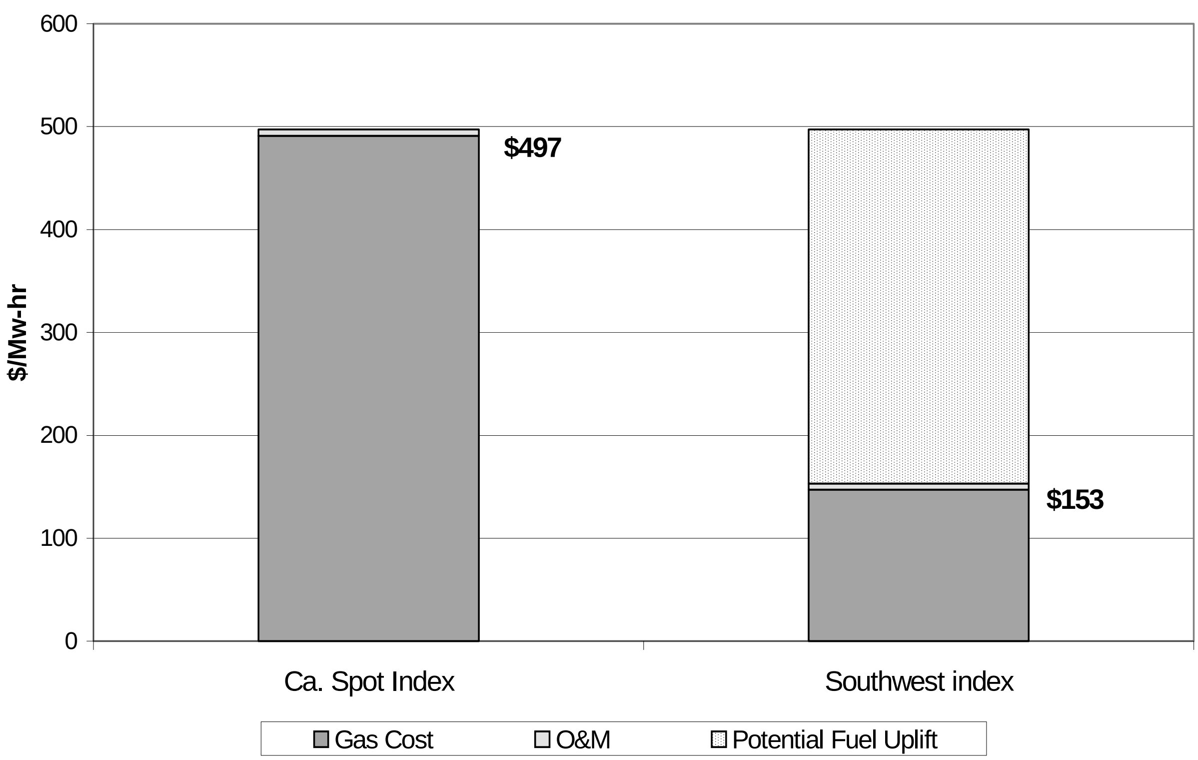
C. How the Substitute Natural Gas Index Would Work

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]

[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.

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.

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

[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.

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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.

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

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

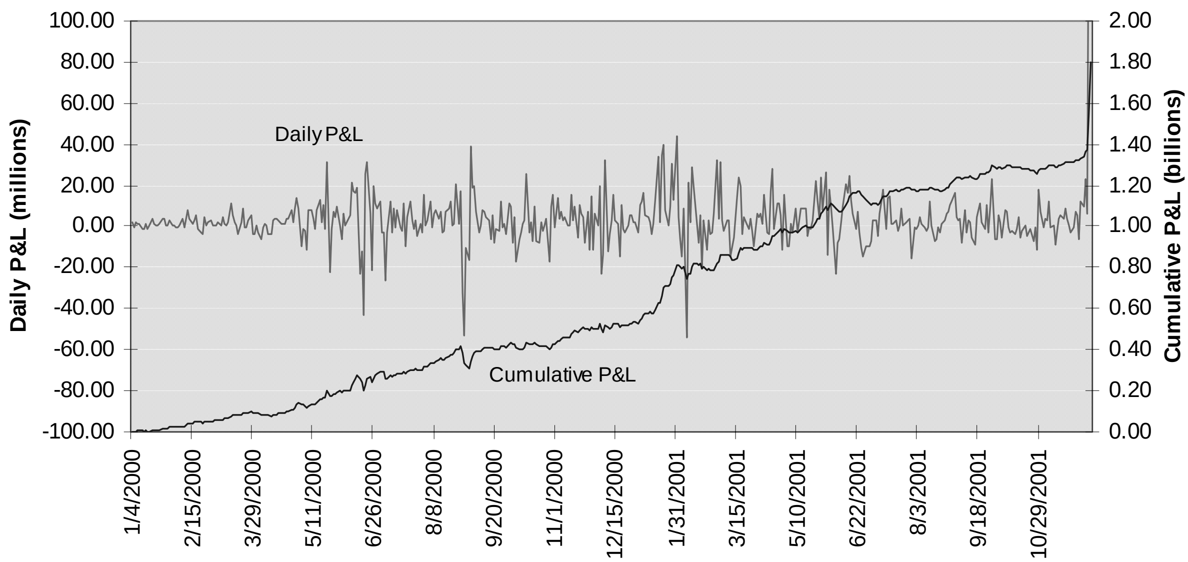
B. The Enron Trading Strategies and Their Impact on Prices

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.

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.

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...)

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.

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

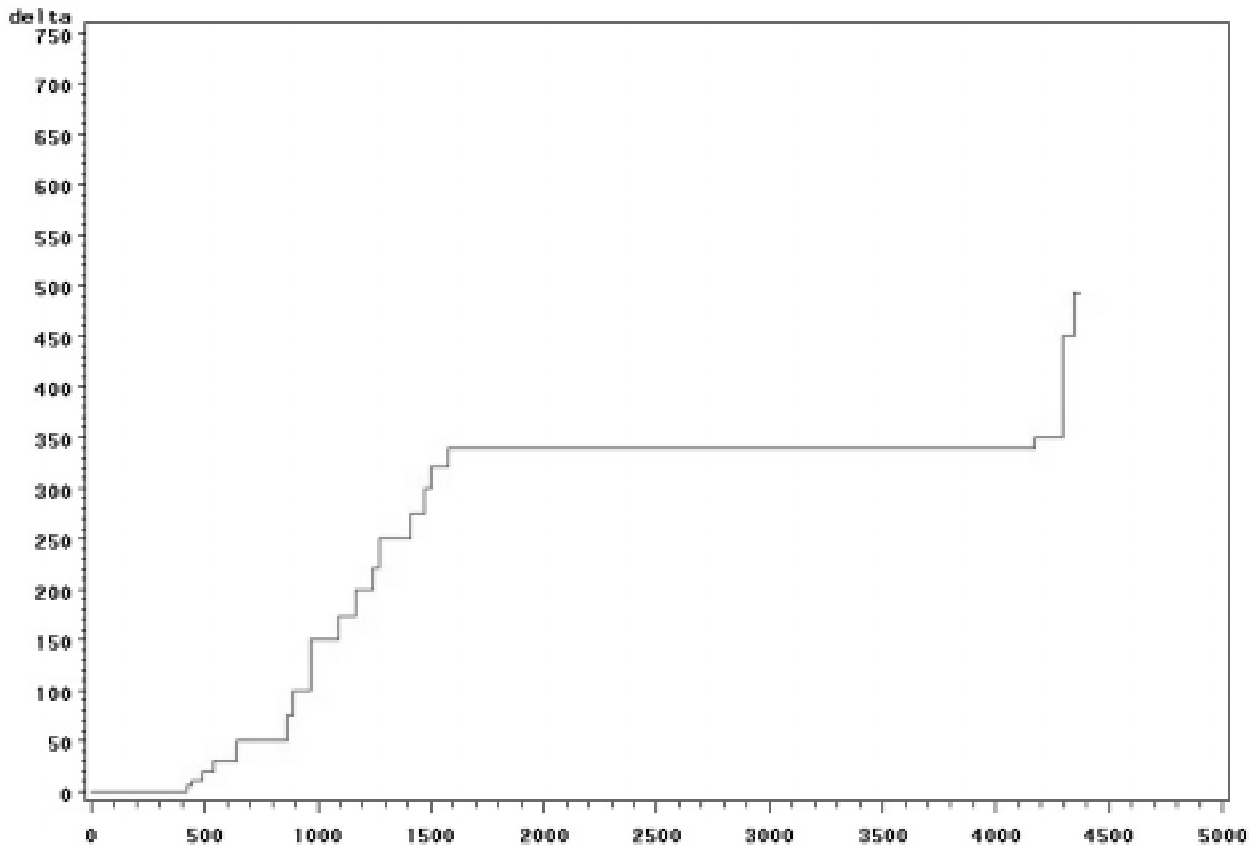

Figure 12: Congestion Price Curve (Prices vs. MWs of Congestion)

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).

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

[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.

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.

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

[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).

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[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.

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-

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[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.

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...)

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.*

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.

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

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

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 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.

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

	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

	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.