Index of Relevant Material Template

Submitter (Party Name)	California Parties
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Privileged Info (Yes/No)	Yes
Document Title	Prepared Testimony of Dr. Peter Fox-Penner on Behalf of the California Parties
Document Author	Dr. Peter Fox-Penner
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	Prices before October 2, 2000 are not consistent with Sellers' market-based rate tariffs and those of the ISO and PX. Prices in the ISO and PX Spot Markets from October 2, 2000 to June 20, 2001 were unjust and unreasonable. Sellers withheld from the market. Sellers generated uninstructed to bypass organized markets. Sellers submitted Bids in the ISO and PX Markets in order to exercise market power. Sellers participated in false load schedules. Sellers participated in Megawatt Laundering or "Ricochet." Sellers participated in "Death Star" or other Congestion Games. Sellers double sold Ancillary Services Capacity. Sellers participated in the "Get Shorty" strategy of selling non-existent Ancillary Services to the ISO. Sellers shared non-public generation outage information. Sellers participated in collusive acts. Sellers' withholding and other market manipulation, not buyer underscheduling, led to forced reliance on the Real-Time Market.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95-000, EL00-98-000 (including all subdockets)
Indicate if Material is New or from the Existing Record (include references to record material)	New
Explanation of what the evidence purports to show	Sellers deliberately and systematically withheld energy from the market, driving up prices by creating false shortages and scarcity. Sellers submitted bids into the PX and ISO energy markets to

	exercise market power. Sellers intentionally submitted false load schedules to increase scarcity and prices in the day-ahead markets and move resources into the real-time markets. Sellers exported power out of California and imported it to sell at inflated prices, creating artificial scarcity and reliability concerns. Sellers shared detailed non-public information regarding competitors' planned and ongoing generation outages. Many market participants, including public power entities, jointly implemented or facilitated Enron-type trading strategies, had and carried out agreements for joint action, and shared competitive market information via trader conversations, industry groups, and information services.
Party/Parties performing any alleged manipulation	Numerous market participants including Sempra, Powerex, Mirant, Dynegy, Reliant, Hafslund Energy, City of Glendale, Williams, Enron, LADWP, Duke Energy, Modesto Irrigation District, City of Redding, City of Glendale, Sacramento Municipal Utility District, Coral Power, and Avista.

* This entry is not limited to the California and Northwest Docket Numbers.

Contains Protected Material *Exh. No. CA-1*
Not Available to Competitive Duty Personnel

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,	)	**Docket Nos. EL00-95-000**
Complainant,	)	**EL00-95-045**
	)	**EL00-95-075**
v.	)	
	)	
Sellers of Energy and Ancillary Services	)	
into Markets Operated by the California	)	
Independent System Operator	)	
Corporation and the	)	
California Power Exchange,	)	
Respondents.	)	
	)	
	)	
Investigation of Practices of the	)	**EL00-98-000**
California Independent System Operator	)	**EL00-98-042**
and the California Power Exchange	)	**EL00-98-063**
	)	

PREPARED TESTIMONY OF
DR. PETER FOX-PENNER
ON BEHALF OF THE CALIFORNIA PARTIES

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I. INTRODUCTION

Q. Please state your name and address.

A. My name is Peter Fox-Penner. My business address is 1133 20th St. NW, Washington, D.C., 20036.

Q. By whom are you employed, and what is your position?

A. I am a Principal and Chairman of *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, Washington, London, and the San Francisco Bay area.

Q. Please describe your educational background and experience.

A. I am an economist and manager with two decades of experience in government and consulting, primarily in the area of regulated utilities. I began my career in 1980 as a research engineer in The Governor's Office of Consumer Services in Illinois, the precursor to the state's consumer advocate. Following graduate school, I worked from 1987-1993 as a consultant to utilities and other energy clients. In 1993, I was appointed Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy at the United States Department of Energy ("DOE"). In this position I directed (among other things) DOE's policy research program on electric utilities and served as a department liaison to state regulators and legislators on utility issues. In 1995-1996, I worked on electricity policy issues as a Senior Advisor in the White House Office of Science and Technology Policy and as a Special Assistant to the Deputy Secretary of Energy. Following government service, I have written and consulted on electric utility regulatory and economic issues and I frequently appear at industry seminars and association meetings. In 1997, I authored *Electric Utility Restructuring: A Guide to the Competitive Era*, a best-selling work on the subject.

I received a Ph.D. in Economics from the Graduate School of Business, University of Chicago, as well as an M.S. in Mechanical Engineering and a B.S. in Electrical Engineering from the University of Illinois. I have testified before this Commission and the public service commissions of Illinois, Massachusetts, Florida, California, Washington, Pennsylvania, New Mexico, Kansas, and Wyoming, as well as various federal courts and the United States Congress (Senate Committee on Energy and Natural Resources and House Appropriations Subcommittees).

Q. By whom were you retained in this proceeding?

A. I was retained by Southern California Edison Company.

Q. What is the purpose of your testimony?

A. In separate concurrent testimonies in this proceeding, experts for the California ("CA") parties have examined evidence concerning a variety of harmful economic actions of sellers in the CA markets employed during the period January 2000 through June 2001 ("the Discovery Period"). This harmful activity includes various forms of economic and physical withholding.

The next portion ("Part A") of my testimony builds on these experts' conclusions to address several related issues. First, I explain how the exercise of market power via the various means of withholding and many of the manipulative trading strategies employed are interrelated, each building on the other. I also explain why scarcity and "scarcity rents" do not adequately explain or excuse withholding and manipulation behaviors. Many of the manipulative strategies of sellers were enabled (*i.e.,* made profitable) by the same market conditions that allowed sellers to become pivotal and therefore profitably exercise market power. Furthermore, these manipulative strategies were created to exacerbate the same sort of artificial shortages created by withholding. That is, they themselves represent a further exercise of market power. In simplest terms, sellers found a number of ways to increase prices that would not have been possible and/or profitable in workably competitive markets.

The second issue I examine is the pattern of conduct among sellers. As I use the term, the pattern of conduct refers to the following sorts of questions: (1) which sellers chose which forms of withholding or manipulative behavior, and when do they use these behaviors? In other words, was the use of withholding behaviors uniform across all generators, suggesting that common factors (such as high input prices or scarcity) explained this behavior, or did different sellers act differently?; and (2) How did the use of these behaviors by different sellers change during the full period as market conditions and market rules changed?

The third issue I examine is the evidence suggesting that sellers had access to, and in some cases created, shared information that facilitated collusive behavior. This has important implications for how the Federal

Energy Regulatory Commission ("FERC," or "the Commission") should treat sellers' exercise of market power via withholding and other actions in the California markets.

For brevity, I will sometimes refer to these three issues as the relationship, pattern, and joint action issues.

Part B of my testimony examines the manipulative practices of sellers in more detail. In this part, I analyze sales and purchase data to determine the prevalence of the use of several manipulation strategies. I also discuss a number of documents discovered that illustrate sellers' intent to use these strategies and other information to manipulate CA markets.

Q. Which economic entities do you focus on, and how do you categorize and describe them?

A. My testimony examines buyers and sellers' behavior in markets operated by the California Power Exchange ("PX") and California ISO ("ISO") markets during the period May 1, 2000 to June 19, 2001 (the "Crisis Period"). Because my focus is mainly on the energy and ancillary services ("AS") sales offers, I refer to sellers equivalently as sellers, generators, traders or in some cases, importers.

Some sellers have direct affiliates who own and/or have the rights to operate significant amounts of generation within CA, whereas others own little or no generation in CA and primarily sell power generated elsewhere. The former category includes five generators ("Big Five") who control the output of most of the generating capacity divested by the California Investor Owned Utilities ("IOUs") – Williams/AES, Mirant, Reliant, Dynegy, and Duke – as well as smaller sellers such as Calpine. The latter, which I more commonly refer to as the traders or importers, includes the affiliates of Enron, British Columbia Hydro ("Powerex"), Idacorp, Sempra Energy Trading ("Sempra") and others. Notably, all of the Big Five had substantial trading operations, and any trader could buy rights to the output of any in-state generator, so any attempt to finely distinguish between the in-state generators and the out-of-state marketers tends to blur.

Q. Please summarize your conclusions.

A. My conclusions are as follows:

- The structure of the markets that supplied the California IOUs prior to January 17, 2001 created a number of incentives for suppliers to withhold power, first from the Day-Ahead ("DA") market run by the California Power Exchange, and then from the Real-Time ("RT") balancing markets operated by the ISO. The same structure also created the incentive and ability for suppliers to engage in manipulative trading practices known as the Enron strategies and their variants, such as "megawatt laundering". The economic impacts of many manipulation strategies employed by traders or marketers were similar to the impact of bidding and withholding strategies used by generation owners. The fundamental goal of all the strategies was to create a perception of scarcity by making less energy available in the DA markets (when there was time to react and buyers had the ability to guard against high prices through sloping demand curves) and to instead sell power at the last minute, when the need for energy to keep the lights on trumped other considerations.

- There was a widespread pattern of supply withholding by most of the major sellers in the California power markets ("CA markets") starting in May 2000. There was also widespread use of many of the manipulative trading practices identified in the "Enron memos" of December 6, 2000 with colorful names such as Death Star, Fat Boy, and Get Shorty.[1] Four of the five in-state generators engaged in physical or economic withholding on a routine basis during Summer 2000 and continued thereafter. Use of the manipulative trading strategies was at least as prevalent, with more than 16,000 probable distinct manipulative trades identified during the Crisis Period.

- The specific type of withholding practices varied somewhat by supplier and time period, but included: (1) withdrawing supply from the PX DA market through a variety of operational and trading strategies; (2) economic withholding from the ISO's RT market by submitting bids far above marginal costs or by not bidding at all; (3) not bidding into any markets during times of system emergencies; (4) declaring units out of service for purely economic reasons, or otherwise providing misleading outage information; and (5) raising bid prices during periods of high

[1] Exh. No. CA-78.

demand. Some in-state generators supplemented their strategic bidding by selling power to the ISO even when their high bids were not accepted, giving themselves a low-risk "fallback" if their excessively-priced bids were not selected by the ISO. Mirant was particularly aggressive in this regard, running "uninstructed" in 30% to 50% of all active hours from June through September 2000.

- The Commission has recognized and applied sanctions to Reliant as a result of its intentional withholding of supply on June 20-21, 2000. Episodes akin to the Reliant behavior were common throughout the Summer of 2000 and during periods of high prices thereafter. Four of the five major in-state generators—Williams, Dynegy, Mirant, and Reliant (the "Big Four")—frequently did not offer all economic supply to the market, offered it at prices far above estimated marginal cost based on their market positions, withheld bids during emergencies, and raised bids during high-demand periods and emergencies. Even if all physical plant outages and reserve shutdowns are assumed to be legitimate, Dr. Reynolds finds that the level of withholding by the "Big Four" exceeded 1,000 MW in about 40% of all on-peak hours during the Summer 2000 and only slightly less during the Fall. During the Summer 2000 such withholding exceeded 2,000 MW in about 12% of all on-peak period. Such withholding contributes to a perception of scarcity even if supply is physically sufficient to meet demand.

- In addition to economic withholding through their bidding practices, generators frequently removed units from service for false or purely strategic reasons, including during declared emergencies. Mr. Hanser finds that all of the five major in-state generators either declared outages under suspicious circumstances or put units on reserve shutdown in more than twenty instances between June 2000 through June 2001.

- There was widespread, pervasive use by numerous sellers of the manipulative strategies made famous in the Enron Memos. The most prominent strategy used was "Ricochet" (or "MW Laundering") in which power from within the ISO is exported from the DA markets and re-imported at higher prices into the ISO's RT market or as Out of Market ("OOM") purchases. This

strategy, which is also a form of economic withholding, was sometimes executed by a single seller (who both exported and imported the power) and sometimes by two or more sellers working in concert. Using an approximate screening technique, but limiting myself only to Ricochets done by a single seller, I have identified approximately 15,000 hours in which more than 2 million MWh appear to have been shifted between these markets throughout the Crisis Period. A large number of Ricochets have evaded identification because their design makes their difficult to detect (purposefully in some cases). MW Laundering through multi-party transactions likely exceeded these levels substantially, potentially reaching levels averaging 2,000 MW during peak hours in August and November of 2000.

- Although the Ricochet strategy was used by over twenty sellers, including Williams to a great degree and also Duke and Reliant, the predominant users of this strategy were traders: Powerex, Sempra, Enron, and several others. Through these Ricochet trades, these traders exported power and re-sold it back to California at prices as high as $1400/MWh. This strategy was not only used widely in the Summer and late Fall of 2000, but was also used to evade the soft caps and refund liabilities that began in December 2000 and continued into Spring 2001, when many sales to the State of California acting through the California Energy Resources Scheduler ("CERS") appear to have been exported from CA in the first place and then resold to CERS at a lucrative markup. This manipulation strategy probably played a major role in the fact that Powerex (British Columbia Hydro) reported in excess of $1 billion of trading profits a year.[2] Ricochet trading was facilitated by cooperation between traders and most control area operators in the Northwest and Southwest. Some sellers, such as Reliant, appear to have undertaken efforts specifically designed to hide Ricochet transactions. Others suppliers, such as Dynegy and Sempra or Coral and Glendale, cooperated in a likely effort to make detection more difficult.

- The second most prevalent manipulation practice was the scheduling of false load, also known as "Inc-ing Load" or "Fat

[2] Exh. No. CA-196 at 1.

Boy." This strategy was used by at least twenty sellers throughout the Crisis Period. Remarkably, six sellers who had never had a single megawatt-hour of actual load, scheduled power for false loads for more than 5,000 hours during this period. This strategy also withdraws supplies from the DA market in order to benefit from high, manipulated prices in the ISO's RT market. The most active users of Fat Boy-type strategies were Enron, Sempra, Powerex, Mirant, Hafslund Energy Trading and the Cities of Anaheim and Pasadena. It was also implemented in close cooperation between traders and public power entities, such as the city of Glendale.

- Two other manipulative strategies, Death Star and Cut Schedules, involve receiving payment for phantom power flows that received payments for relieving transmission congestion even though no congestion was actually relieved and no power actually flowed. Using an approximate data screen on transactions by single sellers, I find that more than 1,000 potential Death Star trades were made by roughly a dozen sellers during this full period, most notably Enron, Coral, Sempra, and Morgan Stanley Capital Group ("Morgan Stanley"). Trading records obtained in discovery also indicate that the Modesto Irrigation District ("MID") was one of the most prolific users of Death Star-type transactions, implementing such trades nearly every day from at least June, 2000 to February, 2001. Death Star-type congestion games were also implemented through profit sharing agreements between traders and public power entities such as NCPA, MID, Glendale, Redding, and, most likely, the Los Angeles Department of Water & Power ("LADWP"). A second strategy to get paid for fictitious congestion relief, Cut Schedules, was found to have been used several hundred times. The primary users of this strategy were Dynegy, Morgan Stanley, Sempra, Powerex, Enron, and Coral.

- Another widely used strategy throughout the May 2000 through June 2001 Crisis Period was "Get Shorty," which involved the sale and repurchase of AS that either were non-existent or never intended to be delivered. During hundreds of hours, importers such as Enron, Sempra, Coral, MID, Avista, and the City of Azusa ("Azusa") delivered none or only a fraction of the ancillary services that they sold. During the Spring of 2001,

some sellers —such as Coral, MID, Avista, and Azusa—never (or almost never) delivered AS to the ISO, despite heavy Get Shorty-style sales and repurchasing of these services. This significantly increased the ISO's ancillary service costs and also created reliability concerns. Similarly, I found that during four out of the Big Five generators—Dynegy, Mirant, Duke, and Reliant—engaged in significant "double selling" energy from ancillary service capacity that was supposed to remain unloaded.

- Of perhaps the greatest concern to me among all of the evidence on the use of withholding and manipulative trading strategies is the significant evidence that many of these withholding and trading strategies were coordinated, actively or indirectly, among groups of sellers. The Commission is already aware of the fact that Enron entered into a number of agreements with utilities throughout the West designed to facilitate its trading strategies. The CA Parties have discovered several additional agreements of this nature not involving Enron but raising equally serious issues. One agreement between Avista and Riverside explicitly calls for the sharing of commercially sensitive information and then goes on to contain an agreement not to compete for each others' retail customers.

- The CA Parties have discovered many communications between traders where competitive information is shared or disclosed, and many communications in which two sellers agree to undertake one or more manipulative trades together. In addition, the CA Parties have discovered that a number of sellers subscribed to an information service known as Industrial Information Resources Inc. ("IIR") which provided subscribers with immediate information on the plant outages of some of their competitors – information that IIR obtained directly from personnel for the companies experiencing the outage, some of which were simultaneously receiving outage information from their competitors through IIR. When combined with the attributes of the CA markets and the availability of RT price and other information from other sources, this information service raises the likelihood that sellers were able to coordinate their pricing and supply strategies.

- Some sellers have claimed that the price increases in the CA markets were the result of "scarcity" and "market fundamentals," including increases in the cost of all inputs required to produce power. I find that these claims are deceptive because they fail to account for the fact that true imbalances between marketwide supply and demand (*i.e.,* scarcity), if large, create the incentive and ability to exercise market power and manipulate markets. When such high levels of true scarcity from unmanipulated market fundamentals beget additional artificial scarcity and market power, observed prices no longer send efficient investment or consumption signals.

- Dr. Harris examines whether the cost of a key input to CA power generation, natural gas, was intentionally inflated by these sellers or their affiliates. Dr. Harris finds that Reliant engaged in a very significant volume of wash trades with Enron during the month of December at prices escalating from $12 to $66 per Mite. December, of course, was a month marked by the move to the soft cap in the ISO and by a tremendous run up in natural gas prices. Dr. Harris notes this evidence is particularly relevant in light of representations by Reliant chairman John Stout to the Commission that index prices should be relied upon in setting the MMCP.

- Dr. Stern examines the contention that high CA market prices were caused by the CA utilities failing to purchase all of their demand in the PX markets (so-called underscheduling or undersupply). Dr. Stern finds that (1) underscheduling was caused by the withholding behaviors of sellers, who withdrew approximately 8,000 MW in the aggregate, or nearly 20% of supplies, from the PX markets between August 1999 and August 2000, making it impossible for the IOUs to purchase their power needs from the PX at any price; (2) in the few instances in which sufficient supply was bid into the market during emergency hours, had this supply been offered at reasonable prices, as proxied by the Commission's MMCP, the proportion of supply purchased by the IOUs would have come close to meeting the IOU's standards, suggesting that underscheduling by the IOUs was not a problem; (3) had the IOUs offered to purchase all of their demand at the PX's maximum price of $2500/MWh, as the sellers suggest they should have, they would not have been able

to purchase their full load during virtually any emergency hours because insufficient supply was offered, but the cost of electricity to consumers would have increased by more than $6.76 Billion.

- The closely woven relationships between manipulation and withholding behaviors, and the fact that multiple sellers engaged in both types of practices at the same time, renders it extraordinarily difficult, if not impossible, to isolate the economic impacts of one particular seller or one episode of market power exercise or manipulation. The impacts also blended across time in important ways. Some of the manipulation strategies were systematic and continual or near continual. And the strategies could have an impact on an array of sellers who had not originally participated in the strategy. The manipulative strategies thus perpetuate themselves, and spread, impacting all market participants.

- I also find that there is no economic basis for excluding the two types of transactions the Commission has thus far excluded from refunds, exchanges and multi-day OOM transactions

- Finally, withholding and manipulation were not limited to the California spot and day-ahead power markets. The evidence demonstrates conclusively that some suppliers, such as Reliant, intentionally manipulated CA short-term energy markets with the specific purpose and effect of manipulating longer-term forward contract markets to their advantage.

- Taken together, this pattern of conduct indicates that market manipulation and the exercise of market power were widespread and willful acts undertaken in the California markets by many sellers. These harmful economic acts were neither infrequent nor limited to just one or two "bad actors." While not universally used by all sellers, the market manipulation strategies impacted the market prices paid to all sellers, and thus fundamentally impacted all market results throughout the entire period of May 2000 (when the first major manipulation induced price increases occurred) through June 2001.

Q. What documents and data do you rely on?

A. I rely on many documents and data sources obtained by the CA Parties from discovery in this proceeding. I also rely on published and discovered reports from the California ISO and PX (Exh. Nos. CA-285 to CA-291), and other public domain information.

Q. How is the rest of your testimony organized?

There are two parts to my testimony. Part A of my testimony provides an overview of the structure of, and conduct in, the California markets during the Crisis Period. Part B of my testimony examines the use of harmful trading strategies. In Part B, I present evidence identifying specific sellers that engaged in trading strategies that were economically harmful, and that had harmful reliability impacts, during the crisis period.

In Section II of this part of my testimony, I describe the structure of electric power markets during the crisis period. I explain how the structure and timing of the California short-term energy markets makes them particularly vulnerable to the exercise of market power through the withholding of energy from DA and RT markets, and to market manipulation via Enron-type trading strategies.

In Section III of Part A, I summarize the evidence presented by witnesses for CA Parties on the patterns of harmful withholding and manipulation by sellers in the CA markets during the crisis period. I show that these economically harmful strategies were pervasive in that they were used by many sellers. I also show that although sellers changed their strategies throughout the crisis period as the California market structure changed, economically harmful strategies were widely used throughout the Crisis Period. They were used to a greater extent when sellers' incentives profit by using harmful strategies were greatest, suggesting that sellers acted with intent.

Section IV of Part A examines the economics of scarcity rents in electric power markets. I argue that while scarcity rents are useful in that they provide generation owners a return on capital investment, that prices and scarcity rents may not necessarily reflect either true shortages or the value of power. Rather, high levels of price and scarcity rents may be the result of the exercise of market power.

Section V of Part A examines evidence of non-competitive conduct by sellers in California electric power markets. This section examines a

variety of conduct. I examine evidence of seller withdrawal from forward markets using the model for manipulation developed in Section II. I also review evidence presented by other CA Parties witnesses concerning patterns of economic and physical withholding. Finally, I review evidence on the export of power from CA, arguing that the export of power has an effect on markets that is akin to that of other forms of withholding in that exported megawatts are no longer available to satisfy the load obligation of the IOUs and DA markets.

The final analytical section, Section VI examines the use by sellers of trading strategies aimed at the manipulation of electric power prices. Certain of these strategies have been documented in the now-infamous Enron Memos. Participants in these manipulative schemes included all manner of sellers–the Big Five generators, traders, as well as public power providers and municipal utilities.

PART A
OVERVIEW

II. THE STRUCTURE OF THE CALIFORNIA MARKETS CREATED A CLOSE, SYMBIOTIC RELATIONSHIP BETWEEN WITHHOLDING AND MANIPULATION STRATEGIES

A. THE STRUCTURE AND TIME SEQUENCE OF CALIFORNIA POWER MARKETS

Q. What is the distinction between withholding and market manipulation in common economic usage?

A. Many forms of economically harmful market conduct can be classified as either a manipulative practice or a form of market power exercise. More commonly, withholding is used to refer to actions by sellers that cause some economically saleable capacity to remain unsold to raise the price of remaining sales, while manipulative practices refer to a variety of actions by traders that are not consistent with fair and effective competition, such as falsifying information used by market participants.

In the CA power markets, the various forms of withholding and manipulative practices were related and symbiotic. To understand this point, it is necessary to examine the market structure in which all of these harmful practices occurred.

Q. Please describe the main structure of the California short-term markets.

A. Between April 1998 and January 17, 2001 there were four primary short-term CA markets in which WECC generation could be offered: (1) bilateral short-term markets; (2) the DA market and Day-of or Hour-Ahead ("HA") markets (collectively referred to simply as DA) operated primarily by the PX; (3) the ISO's RT market, along with a related market for some forms of AS that provided reserve capacity and could provide RT energy to the ISO; and (4) the ISO's OOM "purchases."[3]

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[3] As explained below, it is possible to view the RT market and OOM purchases as a single market, and many accounts of the CA market structure do this. However, it is easiest to understand the relationship between withholding and trading strategies if these two "markets" are treated distinctly in this exposition. The markets into which generators could offer their capacity were the AS market, which indirectly serves the RT markets. For the purpose of meeting total hourly power demands, the

(The second of these markets was effectively eliminated on January 17, 2001 at the start of what I call the CERS period; I discuss this period further below.)

Q. Who were the buyers, and who were the sellers in each of these markets?

During this period the three IOUs generally could not buy from the physical bilateral market, so total IOU demand in any one hour had to be met from the sum of PX and ISO supplies.[4] As a result, the supplies dedicated to the bilateral market were effectively withdrawn from supplying IOU demand, which was the vast majority of power demand in the state.

This has important implications. A market is a place where sellers and buyers come together to make voluntary trades. Limits placed on buyers or sellers choices with regard to who they can sell and buy from, will tend to reduce competition and make the market vulnerable to market power abuses. Of course, the existence of such limits was exactly part of the problem faced in California. The fact that essentially all IOU demand had to be supplied from the PX and ISO markets left the IOUs exceptionally vulnerable to manipulation of these markets. IOUs simply were not able to counteract such manipulation through bilateral purchases by purchasing bilaterally.

Since California IOUs were not allowed to purchase directly in the bilateral markets, a decision by a supplier to sell power bilaterally also meant that the buyer could not be a California IOU or the ISO.[5] Power sold bilaterally would either have to be exported, used to supply the small amounts of non-IOU load that existed, or sold to others who, at some markup, resold it into the PX, ISO, or export markets.

RT market here and throughout my discussion includes AS bids called by the ISO to provide RT energy.

[4] The IOUs also still had some of their own generation facilities in this period, but until January 2001 all output from these facilities was bid into the PX or ISO markets. In addition, the IOUs were granted permission to enter into physical bilaterals on August 3, 2000, though with essentially undefined prudence standards.

[5] Note that a bilateral sale was the equivalent of withdrawing the power from a clearly-defined set of buyers, the California IOUs. In this sense, the IOUs were a "destination market" as defined by the Commission in Order 642 and as used by the Commission for many years in its analysis of competitive conditions.

The sellers were all those generators or importers who chose to sell to the PX. In addition, until January 2001, the CA IOUs were required to bid the generation they continued to own into either the PX or the RT market. Other than the CA IOUs, no sellers were required to sell their capacity into the PX markets.

Because the RT and OOM markets operate within only a few hours of the time power is consumed, demand and supply in these two markets must balance. All purchases made in these markets were made centrally by the ISO itself and allocated back to the IOUs. (For this reason, the ISO-operated RT and OOM markets are sometimes referred to as balancing markets.) In summary, the sole buyer in the ISO markets was the ISO acting on behalf of the CA IOUs and other market participants.[6] The sellers were again the group of generation owners and importers who chose to sell to the ISO.

Q. Please discuss the time sequence of these markets.

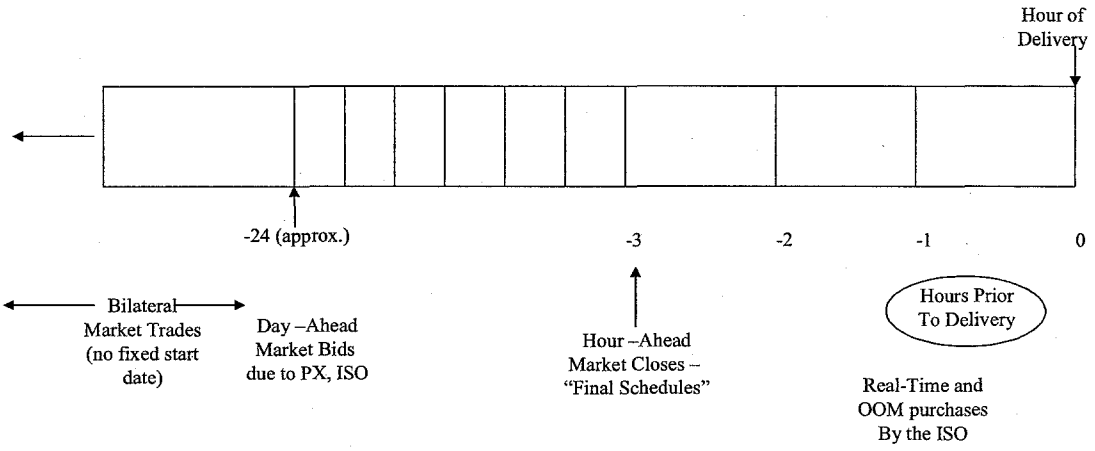
A. There was an important time sequence to these markets. For deliveries for any given hour, bilateral trading could occur as far in advance of the delivery hour as the parties agreed. DA trading essentially occurred in a one-time auction the day before the day of delivery (*i.e.,* generation of the power) and HA trades occurred about three hours prior to the hour of delivery, also known as the operating hour. As explained below, RT purchases occurred within the hour or two prior to the delivery hour and within the operating hour. OOM purchases were made by the ISO at whatever point it determined that a shortfall in energy could occur. Typically, this occurred after the DA market closed and before the operating hour. Note that this means that the ISO's OOM market and RT market were often effectively both trading at the same time. Note, however, that the price for RT energy is determined within each operating hour on an *ex-post* basis. Figure 1 provides a simplified timetable for these markets for reference.

As explained below, this time sequence has important implications for seller and buyer choices and the mechanics of market power exercise and market manipulation.

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[6] During the CERS periods CERS assumed the role of the ISO in the OOM market, buying on behalf of the IOUs and other market participants. However, during this period the ISO still determined when OOM purchases were necessary. CERS simply guaranteed payment for OOM purchases.

Figure 1
Simplified Timeline
California Short Term Markets

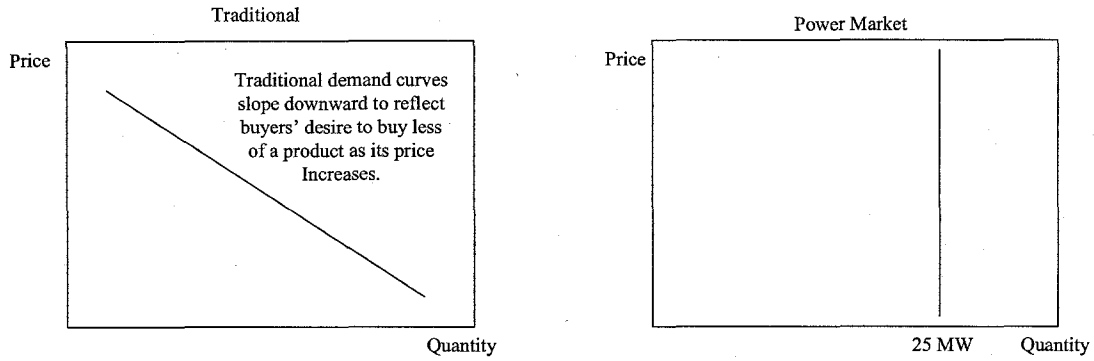


B. STRUCTURE OF DEMAND AND SUPPLY IN THESE MARKETS

Q. Please explain the main features of demand in present-day short-term power markets generally.

A. In electric power markets the total demand of a system must be supplied instantaneously or the system collapses. If electricity is being purchased in a market, and the required quantity is 25 MW in order to avoid system collapse, then in most electric markets there is a system operator who is charged with ensuring that the sum of all purchases on the system is 25 MW regardless of the price charged. Thus, in all electric power markets the ultimate demand curve is essentially a vertical line ("price-inelastic demand curve") rather than the traditional sloped demand curve. This is illustrated in Figure 2.

Figure 2
Traditional and Power Market Demand Curves



Q. What are the general implications of this price-inelastic demand curve for the incentive and ability for suppliers to manipulate the price of power and/or exercise market power?

A. Markets with price-inelastic demand curves offer sellers a significantly greater incentive and ability to profitably exercise market power or to manipulate the market profitably. This follows from the simple fact that the quantity of product purchased by the buyer is not reduced as price increases. In ordinary markets, sloped demand curves mean that buyers will buy less, when prices rise. Thus, any seller who raises its price intentionally will sell less, or will cause other rivals to sell less and sellers acting together to raise the market price will collectively sell less. The lost profits from these lost sales reduces the incentive to raise prices.

However, if raising prices does not reduce the sales of sellers exercising market power, there is less disincentive to forgo or moderate the (unilateral or multilateral) exercise of market power.

There is also a time dimension to demand in power markets that renders the RT and OOM markets more vulnerable. By the time the operating hour occurs, the ISO must immediately purchase supplies equal to the as-yet unsupplied demand so as to balance total demand and supply perfectly. There is no time to shop around and compare the prices and other terms offered by sellers and select the best deal. Markets that require purchases within very tight and unforgiving deadlines are especially vulnerable to manipulation and market power.

Q. Did the short-term CA markets have this particular vulnerability to manipulation and the exercise of market power?

A. Only in the RT and OOM markets. The total demand of the buyers in the California markets was divided between the DA market and the later-occurring RT and OOM markets. In the DA markets, the CA IOUs purchased on their own behalf. Because the RT/OOM markets followed the DA markets, the IOUs were not required to buy 100% of their expected demand, regardless of price, in the DA markets. Hence, their demand curves did not have to be price-inelastic in these markets (and generally they were not).

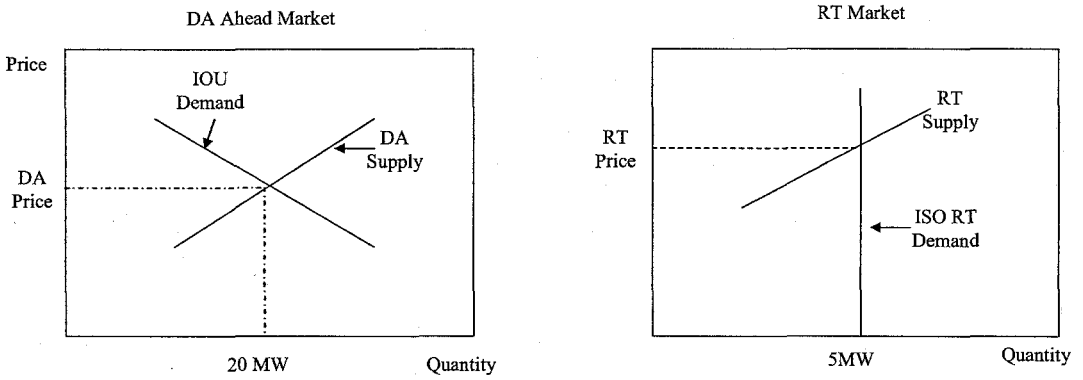
However, the residual of what the IOUs did not buy in the DA markets had to be purchased in the RT and OOM markets. Moreover, in these markets the remaining demand of the IOUs had to be purchased, regardless of price.

More completely, the IOUs had to submit load bids (or demand bids) to the PX market and generators submitted (but generally were not obligated to submit) supply bids. The PX submitted an aggregate schedule to the ISO, by conducting an auction to determine final market-clearing prices and scheduled quantities in the DA market. DA market-clearing prices and quantities were determined based on the intersection of all demand and supply schedules and corresponding buy and sell bid prices offered in this market, including those of the IOUs.[7] If there was no transmission congestion between zones there was a single Unconstrained Market Clearing Price ("UMCP") throughout the ISO; if not, there were separate Zonal Market Clearing Prices ("ZMCPs") by delivery zone.

For any hour, the quantity of IOU demand that was not supplied in the PX market had to be obtained from the ISO's RT balancing market. For example, suppose that the IOUs required 25 MW, but their quantity awards in the DA market only gave them 20 MW. The remaining 5 MW would be purchased for them by the ISO in the RT market; the price paid by the ISO would be charged through to the IOUs (see Figure 3).

[7] Similarly, in the RT market the ISO aggregated all offers to sell into a supply curve and selected as many offers as it needed, ascending by price, until demand was met.

Figure 3
Simplified Structure of the
California Power Markets



As Figure 3 shows, because IOUs could effectively purchase the balance of their needs from the ISO, they were not required to bid as price takers in the DA markets. Instead, they could bid according to the more traditional shape shown in Figure 3, knowing that their remaining demand would be purchased by the ISO regardless of price in order to balance the system. Thus, the ISO's demand curve (on the right side of the figure), which was the residual demand of the IOUs as well as many other last-minute sources of demand, was a price-inelastic demand curve.

In summary, it was not until the final markets (RT and OOM) that the effective demand of the IOUs (as reflected by purchases on their behalf by the ISO) was inelastic. These markets were much more vulnerable to market power exercise and to market manipulation because buyers had no choice but to purchase their residual needs at whatever price was required to bring forth the needed quantity of supply from suppliers.

Q. Did the PX and ISO markets have price limits on them during the Discovery Period?

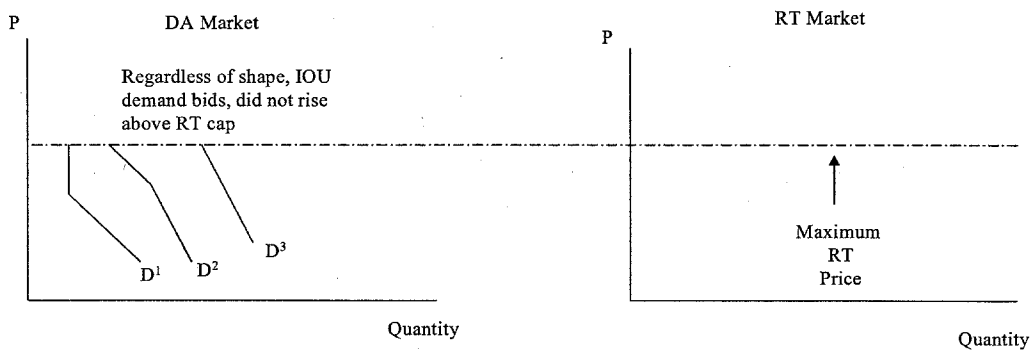
A. Yes. Throughout its existence, the PX had a price cap of $2,500/MWh. The ISO's RT market had a price cap of $750/MWh from September 30, 1999 until July 1, 2000, $500/MWh from July 1 to August 6, 2000, and $250/MWh from August 7 to December 8, 2000. Starting December 8, 2000, the RT market operated under a $250/MWh soft cap. As of January 2001, the PX and ISO operated under a $150/MWh "soft cap." The soft cap was not a true cap, but was instead a limit on the market

clearing price. Bids above these soft caps could be accepted, on a "pay-as-bid" basis. The ISO later operated under other price mitigation schemes, all of which will be discussed further below.

Q. What were the implications of these price limits for demand behavior by the IOUs?

A. Prior to the soft cap, IOU buyers in the PX market generally capped their demand bids at the ISO price cap. The reason is obvious: if the most they could pay for the portion of their demand served in the RT market was capped, they were unwilling to pay more than this price in the DA market. Hence, IOU demand bids had shapes that varied roughly between the forms shown in Figure 4. In all of these demand bid shapes there is no way for the PX auction to clear (*i.e.,* for supply and demand to intersect) at prices above the ISO cap.

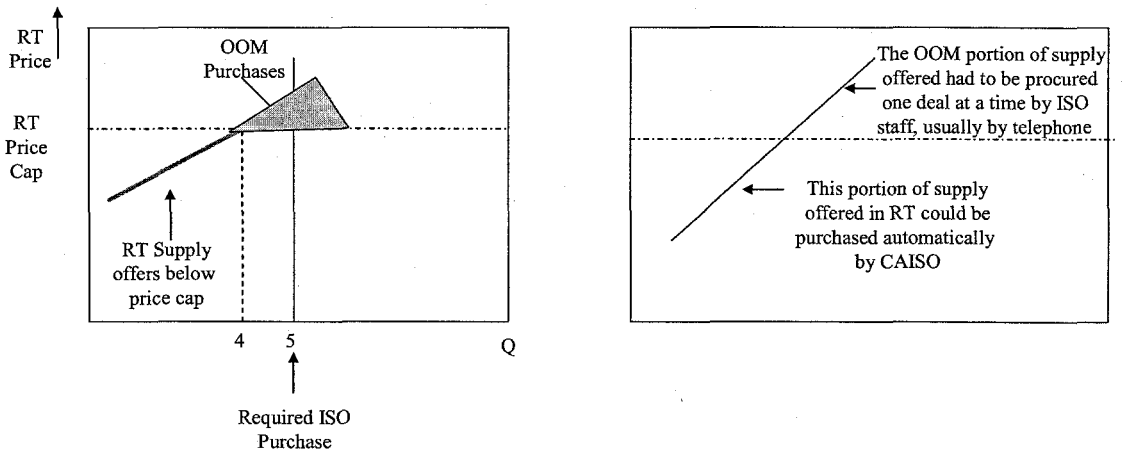
Figure 4
IOU DA Demand Bids Did Not Offer Prices Above RT Price Caps



Q. What were the implications of this demand structure for the ISO's purchasing behavior on behalf of the IOUs in the RT and OOM "markets?"

A. Remembering that the ISO's RT markets had a price cap until December 8, 2000, suppose that the ISO's RT demand for an hour was 5 MW, but that only 4 MW was offered to it for a price less than the cap. This scenario is illustrated in Figure 5.

Figure 5
RT and OOM Supply Market



Since the ISO is required to purchase the full 5 MW of demand, it must find additional sellers beyond those willing to sell out prices below the price cap. To do this, it must be willing to pay more than the price cap, as shown as the shaded triangle in Figure 5. These emergency purchases, which occurred largely in times of extreme shortages of supply, including times when supply was insufficient in the RT market, constitute the OOM purchases.

In short, OOM purchases and RT markets are an unusual combination in OOM purchases and RT markets that both have only a single buyer with inelastic demand, the ISO, which re-allocated all purchases to the ultimate buyers. The ISO first attempts to buy all it expects it will need from RT market suppliers, at capped prices, and buys from the effectively uncapped OOM suppliers only when RT supply offers are expected to be inadequate relative to required demand in the operating hour.

Q. What was the basic structure of the ISO's demand for AS and how did AS relate to RT energy purchases by the ISO?

A. The ISO's demand for AS is detailed in Section 2.5 of the ISO tariff. The quantity of AS the ISO procures in any hour is dictated by WSCC and NERC reliability standards, particularly the WSCC's Minimum

Operating Reliability Criteria. In addition, effective August 1999, the ISO could procure replacement reserves up to the difference between forecast and scheduled load.[8]

Generators who are selected to provide ancillary service capacity (other than regulation up and down) submit a schedule of prices for each increment of energy to be provided in RT. This schedule indicates the price needed to provide the next increment of energy out of the capacity being set aside to provide AS. For instance, a generator selected to provide 20 MW of spinning reserves may submit a corresponding energy bid that indicates that the first 10 MW (out of that 20 MW award) will be provided if the RT price reaches $75/MWh and the remaining 10 MW will be provided if the RT price reaches $125/MWh. Generators who are not selected to provide ancillary service capacity can still offer to sell RT energy by submitting a supplemental energy bid.

The ISO effectively reduces available operating reserves when it calls a unit providing an ancillary service to provide energy in RT. The ISO may skip over an energy bid provided as part of an ancillary service award if it feels the corresponding reduction in operating reserves impairs system reliability. This action is referred to as going "out-of-sequence."

C. BASIC PROFITABLE WITHHOLDING STRATEGIES IN THIS MARKET STRUCTURE

Q. What were the basic options for sellers in these markets?

A. Suppliers faced the following choices for their supply:

- Sell generation bilaterally to non-IOU buyers. With some exceptions, this was essentially the same as exporting generation out of the ISO and making it unavailable to serve IOU buyers via the DA and RT markets, as these were the only two markets in which IOUs could buy generation.

- Offer generation in the PX-operated DA market. Note that whatever was not sold in this market could still be bid into the

[8] Redondo Beach LLC et al.,87 FERC 61,208 at 61,811 (1999) (FERC order on ISO Ancillary Services Redesign).

RT market, as the RT market opened after the DA market closed and all sellers knew their actual DA quantities sold.

- Bid replacement reserves and other AS into the ISO-operated DA ancillary services markets. If the ISO accepted these bids, the price-capped generation portion of these bids became part of the RT energy supply curve;

- Offer generation to the ISO in the RT energy market at prices below the RT price cap; and

- Sell generation only to the OOM market, potentially at prices above the cap or in multiple hour blocks.

Q. In what time sequence did sellers have to decide what to offer in which market?

A. The sequencing of the markets was such that sellers first decided what capacity they would offer to the California IOU's destination markets as a whole. They made this decision by deciding how much to offer into the bilateral markets, which the IOUs could not buy in. Of their remaining supply, they then decided how much to offer to the DA market (including the ISO's DA AS market). Sellers would then offer unsold remaining supply to the ISO's RT energy market. However, they could not offer power to the RT market at prices below the cap and simultaneously hope to sell the same generation to the OOM market at prices above the cap. The RT and OOM markets were roughly contemporaneous.

Q. If these CA short-term markets were workably competitive, would all of these markets for generation clear at approximately the same price?

A. Yes. If competition was strong enough, economic theory predicts that the DA and RT markets would clear at roughly the same price because the two products are so similar. Starting in 1999 and continuing through early 2000, DA and RT prices had arguably started the process of converging. They diverged starting in late May 2000, just as the overall crisis descended.

Q. If workably competitive conditions did not exist, what are the implications of this sequence of markets for sellers' ability to exercise market power or manipulate the market?

A. There are several implications of this market structure for the exercise of market power and the relationship between market power exercise and market manipulation. In a market structure of this type, where sellers are free to choose where to offer their supply, sellers would be expected to choose the combination of markets that offers them the greatest profit. This includes profits earned through the exercise of market power.

Suppose for a moment that a seller was pivotal, *i.e.,* could unilaterally profitably raise prices by withdrawing capacity. Recognizing that the ISO only makes OOM purchases when it is not able to meet RT balancing needs at prices below the cap, the pivotal seller's profit maximizing strategy would obviously be to withhold supply and raise price in either the DA or the RT markets, or both. If this caused the ISO to purchase OOM, the pivotal supplier's profit maximizing strategy could also involve withholding supply from the OOM market.

If prices in the DA and RT markets would not be at the effective or actual level of the price cap absent supply from the pivotal seller, then the pivotal seller has an incentive to withhold supply to raise prices until prices hit the cap. However, because price differences across the two markets could be arbitraged away (either through buyers shifting their purchases to lower priced markets, or other sellers shifting their supply to the higher priced market), it would generally be necessary to raise prices in both these markets.

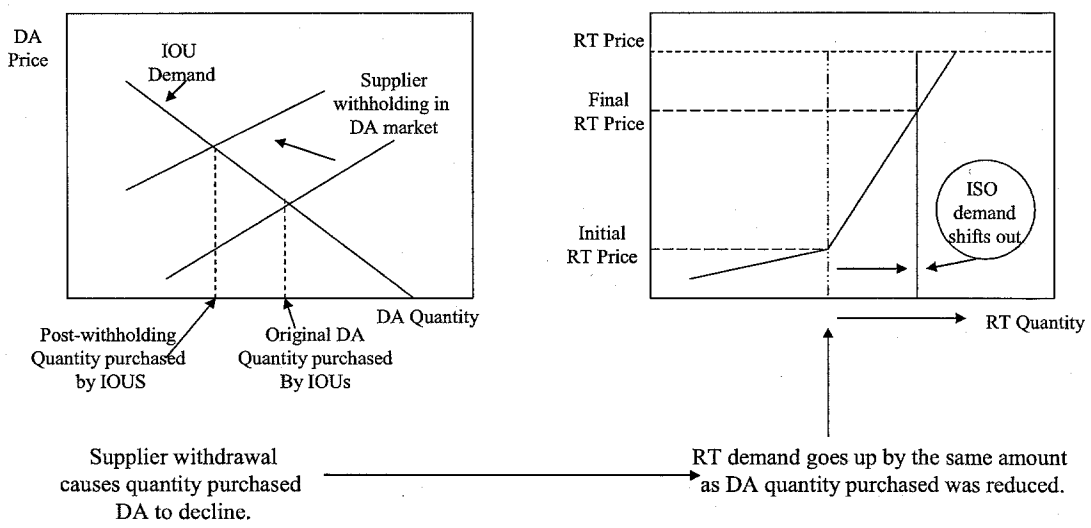
The logical way to do this would be to begin with a withdrawal of capacity from the DA market, either by selling this power bilaterally (so long as such sales were profitable, or as long as the losses on such sales did not exceed the profits earned by withholding from CA markets), selling it to the ISO as reserves or RT or OOM energy, or by not selling it at all. Such withdrawal of supply will, of course, increase DA prices. Furthermore, if it would be possible to boost demand for power in the DA market at the same time that supply was reduced, this would force DA prices up even more.

Following this, the next logical move would be to withdraw capacity from the RT market, as manipulation or market power exercise was particularly profitable in this market.

These basic strategies would work to raise prices only up to the level of the effective and actual caps in the DA and RT markets. To raise prices beyond this, it would first be necessary to ensure that the sum of supply offered in DA was low enough to boost replacement reserve purchases such that generation could "double dip" and receive payments for both reserve capacity and RT energy. An even better strategy would be to cause a shortfall in the DA supply and the ISO's reserves market that was so large that the ISO would be forced to buy OOM.

To implement this broad strategy, the first step is to offer relatively little supply in the DA market. Supply could be exported through bilateral trades (*i.e.,* placing a bid to purchase capacity in the DA market and then exporting the purchase) or simply not offered. The less offered in the DA market, the higher the demand for power at any price in the RT/OOM markets. A simplified illustration of this effect is shown in Figure 6.

Figure 6
Exercise of Market Power by Withholding and Exporting Capacity from DA Market



Note Result: Both DA and RT prices were increased by DA withdrawal.

Note that the impact of the DA withdrawal is to raise prices in both the DA and RT markets, although some of this RT price increase may be offset if the withheld DA supply is bid into the RT market.

Q. Is there any evidence that sellers in the CA markets exercised market power in this fashion?

A. Yes. There is ample evidence that the phenomenon just described occurred before and during the Summer of 2000 and beyond.

First, the testimony of Gary Stern reviews the evidence on underscheduling and shows that several CA generation owners offered successively less power to the PX market between 1999 and 2000. Four of the Big Five in CA reduced supply offers to this market substantially.

A lower baseline level of supply in the PX market makes this market and the ISO markets more vulnerable to additional short term withdrawals of capacity. The Commission has already found that one of the Big Five generators, Reliant, engaged in precisely this strategy on June 20 and 21, 2000 to willfully and successfully raise PX and ISO prices. Figure 7, which is a graph of Reliant's supply offers to the PX and ISO markets each hour from Monday, June 19 to Friday, June 23, illustrates how Reliant used this strategy. Notice that Reliant's bids during peak hours on June 19 and June 20 to the RT market were roughly an average of a few hundred MWs, while nearly all its 2500 MW were scheduled DA. On June 21, it continued to bid a few hundred MW in RT (with some variation), but drastically reduced its DA bids from levels near 2500 MW to levels of roughly 500 MW.

Figure 7
Reliant Energy Services, Inc. Bidding
From June 19, 2000 to June 23, 2000



The effect of these reductions contributed, as illustrated schematically in Figure 6, to increases in DA prices from levels of about $80/MWh to a high of about $120/MWh. At the same time, RT prices rose from the $115 - $135 range to the then-existing price cap of $750/MWh. Thus, this episode illustrates that the greater sensitivity of price to demand increases in the RT market due to the steeply sloped supply curve in the RT market and other factors, is a very real phenomenon.

Notice that in both the schematic Figure 6 and in the actual Reliant episode, it is not necessary that a seller change its bid in the RT market (*i.e.,* engage in further withdrawals beyond that done in DA) to profit from a DA withdrawal. However, sellers in the RT market who know that there is a high likelihood that demand will be shifted out as in Figure 6, are likely either to bid a steeply sloped "hockey stick" in RT, as shown in the shape of the RT supply curve in the figure, or to simply bid at or near the cap when they expect such withdrawals are creating profitable opportunities.

Q. Did withdrawals of capacity from the DA market also boost generators' ability to earn revenues from AS sales?

A. Yes. Generators and traders that withdraw supply from the DA market and shift it into the RT market not only have the benefit of receiving the higher, more easily manipulated RT market price for their energy. Supply shifted into RT generally "double dips" in that it received two payments: (1) ancillary service payment from the ISO for the "reserves" purchased to supply the RT market; and (2) the (*ex-post*) energy payment offered in the RT market. This is because if the ISO saw that the DA market cleared significantly below total forecast demand, the ISO purchased replacement reserves (*i.e.,* ancillary service capacity) large enough to be able to supply the forecast shortfall. Any supply withheld from the DA energy market can be offered as ancillary service capacity, which the ISO will award on a DA and HA basis.

If sufficient reserve capacity could be procured by the time the HA market closes, the ISO could be confident that the RT demand can be met through the RT energy market. The larger RT demand is then supplied in large part out of the procured replacement capacity, and the provider of replacement capacity earned both: (1) ancillary service revenues; and (2) the RT energy price. No such "double dipping" opportunities are available in the DA energy market.

Q. The basic strategy we have been discussing thus far has been to withdraw capacity from the DA market. Could this strategy be augmented (*i.e.*, made still more profitable) by further withdrawal from the RT market?

A. Yes. To raise price even more, the same (or a different but also pivotal) seller could withdraw capacity from the RT market on top of what was withdrawn from the DA market. This would shift the RT supply curve "upward" and to the "left" further, raising RT prices.

There are a variety of ways that supply could be withdrawn from the RT market, including the declaration of a false outage (which also removes capacity from the DA market), simply refusing to bid into the RT market at any price, refusing to sell unless the ISO offers to make OOM purchases at prices in excess of the RT cap, or with a minimum purchase period for the OOM sale.[9]

The testimonies of CA parties' witnesses Philip Hanser, Robert Reynolds, Gary Stern and Carolyn Berry summarized later in this testimony, demonstrate that all these methods were used by various CA market sellers during the Crisis Period.

For any of these actions to be profitable, a seller who withdrew capacity from the RT market would have to find that they earned more on sales from capacity that remained in the market at higher prices than they lost on sales foregone. Suppliers who have a substantial market share and face a price-inelastic demand curve and a steep residual supply curve, as was the case in the RT markets, would tend to find this strategy very profitable.

Q. Is there a further benefit to withholding from the DA and RT markets?

A. Yes. Another advantage of supply withdrawals in the RT market (including withdrawals in the form of a willingness to sell only when prices exceed the cap) is that the RT market becomes exhausted more quickly and the ISO must switch to purchasing OOM at prices above the RT cap sooner.

As in the case of Reliant's DA withdrawals on June 21, 2000, the strategy of intentionally withdrawing power from the RT market was

[9] The forced bundling of OOM hours by sellers is mentioned in Exh. No. CA-237 at 2 concerning a May 22, 2000 episode involving Powerex.

not merely a theoretical possibility in these markets. As an example, during Summer 2000 the ISO investigated Powerex's supply offers to the ISO markets on May 22, 2000. According to a memo to the ISO's general counsel obtained in discovery (Exh. No. CA- 237 at 2), the ISO concluded that Powerex intentionally declined to bid power into the ISO RT market during a high-price, high-load episode and instead waited until the ISO called it for an OOM purchase at a much higher price.[10]

In addition, the CA Parties have discovered an email from Duke dated February 5, 2001 that indicates that while Duke was purchasing power for $155-195/MWh, it looked to sell OOM to CERS at much higher prices:

> *To reiterate if we are ever OOMed **ON ANY UNIT** we want to try to sell CERS (emergency division) at a price of $300 or higher . . . . .but not a penny lower than $175. Most likely they will settle on a price with you around middle 200 hundreds.*
>
> *Also, if we have a unit fail in realtime and we need to buy in the HA mkt (especially in SP15) you should not have to pay above the high 100's (ie $155-$195). All other generators (SCEM, WESC, RELIANT, DYN) would rather sell to us than the ISO. (Exh. No. CA-165 at 2, emphasis in original.)*

A second Duke email notes an unwillingness to sell AS to the ISO at this time (Exh. No. CA-165 at 3).

Q. Please summarize the basic mechanics of profitable supply withholding strategies in the CA power markets.

A. The best overall approach to exercising market power in the CA IOU destination market was to reduce supplies to the DA market, thus increasing demand in the RT/OOM markets, and then to further raise prices via withdrawals, aggressive bidding, and other tactics in the RT markets. Transfers of demand from DA to RT had two beneficial

[10] The timing of the markets required that the ISO determine whether to make OOM purchases slightly before it knows the final RT supply. In the May 22 episode, the ISO did not run out of RT supply once it factored in its advance OOM purchases. As a result, the RT price was below the RT cap. As it happens, the OOM purchases were right at the price cap. The revenues paid to Powerex for this one sale were $1 million more than the ISO would have paid if Powerex had sold at the RT price.

effects from suppliers' standpoints: First, since demand was highly inelastic in the RT market, small amounts of capacity withdrawn from the DA market raise price in both the DA and RT markets. Second, lower supplies in the DA market means the ISO would buy more replacement reserves, allowing suppliers to "double dip" in the RT and capacity markets. Third, the more demand is forced into the RT market, the more likely it is that high price increases are possible (because in the RT market the ISO is a price-inelastic buyer). Fourth, following a shift in overall demand into the RT market, additional physical or economic withdrawals are likely to be highly profitable, especially if they result in an exhaustion of RT supply and force the ISO to make OOM purchases. These RT withdrawals could occur via many tactics, including bidding capacity at very high prices and/or with steeply sloped bid curves, declaring false outages, or simply not bidding at all. Finally, if the partly unpredictable factors that governed the actual total ISO RT demand pushed this demand to high enough quantities, RT prices may spike even higher and the ISO would likely be forced to buy OOM at prices not subject to a cap.

D. SYMBIOSIS BETWEEN MARKET MANIPULATION AND BASIC WITHHOLDING STRATEGIES

Q. What manipulative trading strategies do you discuss in this part (Part A) of your testimony?

A. I review pattern evidence for five major types of manipulation strategies which differ from the withholding strategies already discussed. The following table shows the names assigned to these strategies in the Enron memos, a brief description of the type of strategy, and a very brief explanation of its impacts. The second part of my testimony analyzes these and other strategies in greater detail and provides specific evidence of strategies used by various suppliers.

Table 1

Type of Manipulation Strategy	Brief Outline of How the Strategy Is Effected	Summary Impact of the Strategy on Markets
Fat Boy or Inc-ing Load	Intentionally schedule more load in the DA market than supplier has available to serve	Raises DA prices by making less supply available to serve IOU load that bids into the DA market, and increasing DA demand above true load levels. Adds supply back into the RT market, but unexpectedly in the form of uninstructed generation.
"Ricochet" or "Megawatt Laundering"	Purchase power from the DA market, export it out of the ISO area, and re-import it as a sale to the RT market	Raises DA prices and reduces net DA supply. Provides more supply to RT market, but also increases ability to raise RT prices.
"Cut Schedules"	Withdraw a schedule after the seller has received a congestion relief payment	Does not relieve congestion, but makes payments to manipulator. Raises power costs for all CA market participants.
"Death Star"	Create a circular, self-canceling power flow that collects congestion payments	Does not relieve congestion, but makes payments to manipulator. Raises power costs for all California market participants.
"Get Shorty"	Offer more ancillary services than willing or able to deliver and either buy it back or do not supply it	Raises the cost of ancillary services and hampers system reliability

Among these strategies, the first two are closely related to withholding strategies and are discussed in a moment. The third and fourth types of strategies, Death Star and Cut Schedules, are essentially strategies to collect payments for false congestion relief. These strategies obviously require significant levels of congestion to be profitable. Congestion occurs most commonly, and most severely, where there are localized shortages of supply relative to other parts of the ISO system. The fifth type of manipulation strategy simply involves overselling AS the seller may not possess. This strategy is most profitable when AS prices are higher in the DA market than in RT.

Q. What is the relationship between these manipulation strategies and the basic withholding strategies by pivotal suppliers discussed above?

A. First, I note that a few of these manipulation strategies are not strongly related to the pre-existence of market power or withholding in the energy markets. Clearly not all forms of market manipulation and fraudulent conduct require pre-existing market power in the energy markets.

However, many of these manipulation strategies broadly used in the California markets were made profitable by the elevated level of California electricity prices relative to costs of production, and related high transmission congestion prices. Many of the same market conditions that enabled pivotal suppliers to profitably exercise market power gave rise to profitable manipulation strategies.

In some cases the relationship is even stronger and more direct. The economic effect of some manipulation strategies on the DA and RT markets was nearly equivalent to the withdrawal of capacity by sellers who control power plants within the ISO area. In other words, manipulation strategies were often different sales actions by sellers that were intended to have the same effect as a withdrawal of DA or RT capacity for the purpose of raising prices and seller revenues.

Q. Can you illustrate the symbiosis between withholding and manipulation strategies?

A. Yes. I illustrate this point using one manipulation strategy known as Ricochet, the first strategy in the table above. In a Ricochet strategy, a seller purchases power from the DA market, schedules it for export from California, and then buys the same power back from that market and imports it and offers to sell it in the RT market. In this case, the seller acts as buyer and exporter of DA supply, thus removing it from the supply available to serve IOU demand. This strategy results in an increase in price but, unlike simply "turning a power plant off," the seller does not incur any opportunity cost from forgone output. However, the effect is the same – price is higher in the DA market and the unserved IOU demand shifts the RT demand level outward, raising price and possibly triggering OOM sales, as in Figure 6.

There are two differences between a Ricochet and a "pure" DA withdrawal. First, the Ricochet strategy can be executed by traders

without control over generation resources. Second, the Ricochet causes DA demand to increase, whereas pure withholding from the DA market simply lowers supply. With a Ricochet instead, the ISO sees that an increment of supply that ordinarily would serve IOU load in the DA market has been scheduled for export. Since the ISO forecasts total demand independently, it is more likely to conclude that it will need more RT energy than it had been anticipating prior to the increase in DA demand now scheduled to be sent out of the ISO. Thus, it is more likely to buy replacement reserves and more likely to begin purchasing OOM, both the benefit of all RT/OOM sellers. In short, this aspect of a Ricochet is an enhanced version of a short-term DA withdrawal.

The closeness of this relationship is made even clearer by returning to the Reliant withholding of DA supply on June 21, 2000 shown in Figure 7 above. As explained in the testimony of California Parties' witness Gary Stern and Carolyn Berry, it turns out that Reliant not only withheld DA bids as shown in Figure 7, it also submitted bids to purchase power in the DA market. These demand bids were evidently intended to do exactly what Ricochet purchases do – increase prices in the DA market and make the ISO think that DA supply to the IOUs was short, boosting AS, RT, and OOM purchases and prices.

Q. Do sellers' actual use of this strategy tend to occur more during high-price periods, as one would expect from a strategy that is most profitable when market power is being exercised?

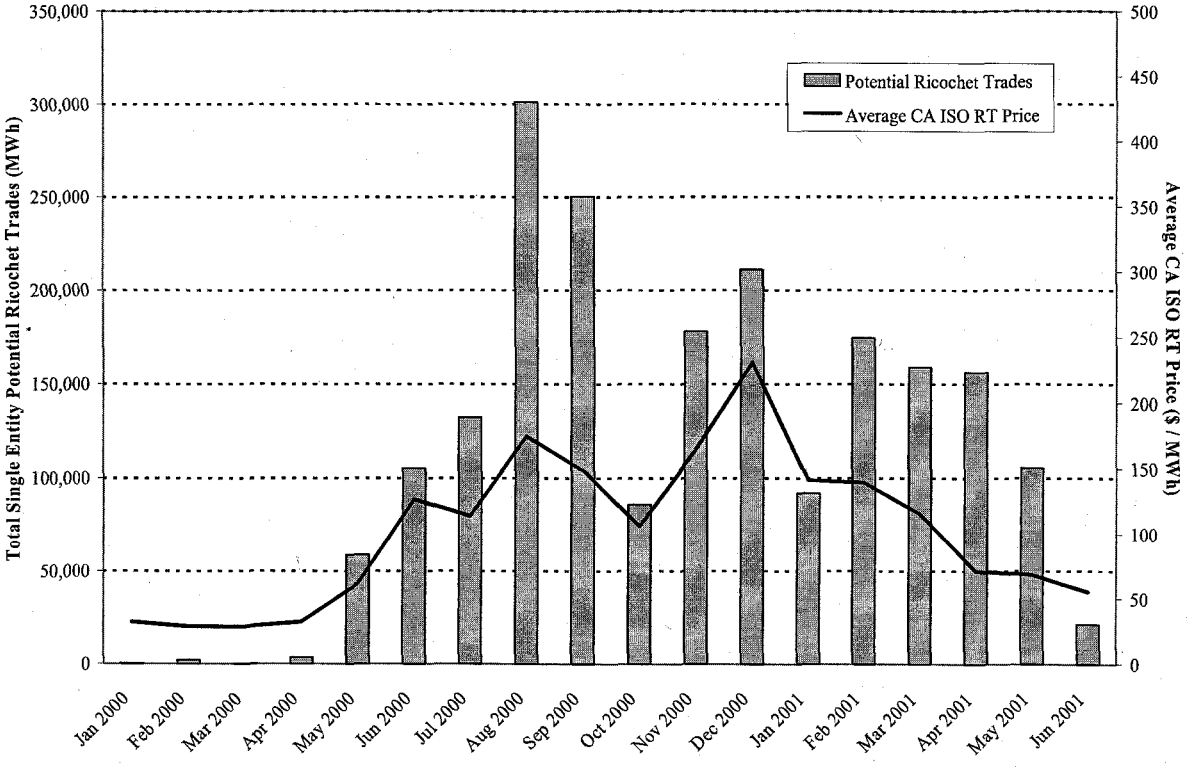
A. Yes, it did. Figure 8 is a graph that shows the total volume of single entity potential Ricochet trades that I have identified, by month, along with the monthly average California ISO RT price (calculated as a simple average of NP15 and SP15 RT prices). The time frame shown on the exhibit begins in January 2000, and ends June 19, 2001.[11]

The figure shows that during Spring 2000, when prices were almost always normal in both the DA and RT markets, there were very few days during which it appears that the Ricochet strategy was used. The strategy began to be used much more in Summer 2000, when RT prices rose, and continued with great frequency when prices rose even higher in November and December 2000. In Spring 2001, Ricochets become entangled in purchases by CERS on the ISO's behalf, and the incidence

[11] Therefore the total potential Ricochet trades in June and the average Real-time price in June are calculated for June 1, 2001 – June 19, 2001.

shifts predominantly to a new set of suppliers. The CERS period is discussed further in Section VI below.

Figure 8
Relationship between Total Single Entity Potential Ricochet Trades and the Average CA ISO Real-Time Price



Notes:
[1]: Source for CAISO RT price is UCEI.
[2]: June 2001 values run through June 19, 2001.
[3]: Average CAISO RT Price is simple average of SP15 and NP15 prices.

Q. Is the Ricochet trading strategy the only manipulative strategy that is symbiotic with withholding and market power?

A. No. A similar chain of reasoning applies to a version of the "Fat Boy" trading strategy. This strategy involves scheduling false load in the DA market. One version of Fat Boy involves buying in DA, scheduling against false load and then selling it in RT. This strategy has the same effect as Ricochet – it raises DA demand, siphoning off DA supply to buyers other than the IOUs and raising DA prices. Using the mechanics of the ISO's market management system, the seller effectively sells the power "purchased" in the DA market into the RT market, just as in Ricochet, though via different specific mechanisms within the RT market.[12] The only difference is that Fat Boy strategy by itself does not directly increase RT market prices, as the increase in RT supply exactly offsets the increased portion of demand that needs to be supplied through the RT market. Moreover, as explained in Part B of this testimony, at least some traders have used such scheduling of fake DA load (Fat Boy) in concert with other strategies, such as aggressive bidding, to manipulate both the DA and RT markets.

Not every manipulative trading strategy is equivalent to a shift of supply from the DA to the RT or OOM markets, plus possible additional withdrawals. However, every trading strategy works off of differentials in prices between different markets, or different zones within markets. These price differences are created or exacerbated by the withdrawal of capacity, or effective withdrawals, by any of the methods by which withdrawals occur. The net total effect of withdrawals of all types is to create the zonal price and congestion conditions that make the manipulative strategies possible.

Q. Please summarize your conclusion regarding the close relationship between withholding and market manipulation strategies.

A. There is a close relationship between market behavior by sellers that withdrew capacity profitably from the California markets, and manipulative trading strategies that exacerbated or profited from the induced shortages, congestion, and high prices. Pivotal sellers' ability to exercise market power was enhanced by manipulation strategies and manipulation strategies were founded on and made

[12] Part B of my testimony explains the sellback in greater detail.

profitable by the exercise of market power. Most of the manipulation strategies would be far less profitable were it not for the market power exercised by pivotal sellers. Conversely, sellers had to determine the profitability of withholding supply by factoring in the benefits from manipulation strategies that also impacted supplies and raised prices.

Q. What are the implications of this symbiosis for estimated the dollar impact of particular episodes of withholding or market manipulation?

A. The closely woven relationship between a wide variety of withholding and market manipulation behaviors, involving a number of sellers in the same markets during the same time periods, means that the impacts of one seller's actions cannot be decoupled from the actions of other sellers. If, for example, Seller B chose to engage in a profitable manipulation that raised DA and RT price because Seller A had already withdrawn enough capacity to make both A and B pivotal, then who should be considered responsible for the composite effect of the two sellers' actions?

The Commission's Mitigated Market Clearing Price ("MMCP") approach in the Refund Docket implicitly recognizes that it is not possible to construct a mapping between sellers' actions and market price effects when multiple sellers are engaging in a number of harmful activities simultaneously. Instead of attempting to disentangle the impact of individual sellers' actions, the Commission established a methodology that mitigates prices to the levels that would have been realized in a well-functioning, workably competitive market. All sellers who received prices in excess of these mitigated prices owe refunds to energy purchasers.

In the following section, I show that the periods of turmoil in the California markets are periods in which many things tended to happen at once. In Summer 2000 four of the Big Five were engaging in economic or physical withholding on many occasions. During the same period, several other sellers were engaging in frequent manipulation trades such as Ricochets. During September and October 2000, when demand apparently dropped briefly to the point where pure withdrawals were not profitable, the same four generators reduced their economic withholding – and the traders

who were using the manipulation strategies in the summer also reduced their use of the strategies.

E. FORWARD MARKET PRICES AS AN INDUCEMENT FOR DA AND RT WITHHOLDING

Q. Have you seen discovery that indicates that forward contract positions created additional incentives to withhold power from the CA spot markets?

A. Yes. Some sellers of spot power in California also held large forward contract positions, *i.e.* contracts to sell power at fixed prices for delivery months or years into the future. Due to mark-to-market valuation of these contracts, their value increased when California spot prices increased and when prices became more volatile. Thus, withdrawing capacity in the spot markets might require foregoing immediate profits, but these losses could be more than offset by the higher valuation of contract holdings.

Evidence of generator upward manipulation of forward prices via PX market withholding has already been revealed in materials released by the Commission in connection with the settlement reached with Reliant in FERC Docket PA02-2-001 for activities on June 21-22, 2000. Discovery by the CA Parties has uncovered more information on Reliant's activities and also revealed that other generators were heavily engaged in trading intended to profit in forward markets as a result of their influence over spot market price movements. The evidence obtained on discovery indicates that profits from such schemes amounted literally to billions of dollars.

The Reliant manipulation that has been publicly disclosed involved the artificial elevation of California spot market prices in order to profit from a long position held by Reliant in forward contracts for the third quarter of 2001 ("Q3 2001"). Thus Reliant's efforts were directed at contracts covering periods then more than twelve months away (the upcoming forward contract would have been Q3 2000). Reliant's plan included the following elements, as revealed in conversations among its traders and schedulers:

- A long position in contracts for Q3 2001;

- Circulation in the marketplace of information falsely indicating that Reliant might have to curtail generation output due to NOx constraints;

- Withdrawal of six generating units from the DA and RT energy markets; and

- Possible supporting activities (purchases) in Q3 2000 trades.

According to the transcripts of trader conversations, if the scheme worked, the traders intended to realize mark-to-market gains in their trading books for the second quarter of 2000 (ending June 30, 2000). If it did not, and losses resulted, then these would be handled on Reliant's accrual (plant) books, thus delaying it for a year. From taped conversations we know that Reliant did accomplish its objectives. The price spike in short-term markets was mirrored by upward movement in Q3 2001 forward positions and Reliant realized a substantial gain to close its June and first half 2000 financial reports.

Q. Was Reliant the only supplier that may have attempted to benefit in forward markets by withholding from short-term markets?

A. No. Discussions among Williams traders in January of 2000 show that they wanted to position themselves long in the forward markets to take advantage of increases in spot prices expected over the summer. In an email discussing this strategy, Greg Hickl, one of Williams trading personnel stated: "We will be prepared both through aggressive trading and operational/AES strategies, to optimize our opportunities when all of the fundamentals come together. Once this happens, everyone will be smoking fat cigars and drinking cold beers (the near years should shift up significantly)." In this conversation, "near years" refers to the next two years from the present during which forward power contracts are offered. (Exh. No. CA-30 at 1) This gain in forward positions would come as a consequence of a run up in summer spot prices. Blake Herndon, another Williams trading strategist, wrote in an email dated January 13, 2000, "...we all feel that you won't see significant upward price action in the forwards until a blow-out is seen in the spot market, *e.g.*, July and August. Where we anticipate

getting huge benefit is in the out months, *e.g.*, '01 and '02." (Exh. No. CA-30 at 1)

By the end of May, Williams traders were concerned that they might miss the price run-up. In an email dated 5/30/00, John Wartes writes to Greg Hickl that instead of being long, Williams is fully hedged for June, if not a bit short. Wartes indicates that he will try to get more length as soon as he can. He cautions, however, "This just to let you know that if the PX blows up the first week, we probably won't make as much as the big dogs think we should." (Exh. No. CA-30 at 4)

As we all know now, prices spiked in the second week in June. Communications among the Williams traders suggests that Williams played a role in these events. In an e-mail dated June 20, 2000 Steve Culliton wrote to Wartes, Hickl and others, "As you are all keenly aware, last week we experienced unprecedented volatility in our market." (Exh. No. CA-30 at 3) The message continues, "With luck, this will be a prelude to the summer market. Tomorrow at our 1:00 p.m. meeting I would like to dissect last week's events and review our collective decisions." He continues, "We can optimally position ourselves for the next "event" by constructively reviewing our actions." (Exh. No. CA-30 at 3)

Ultimately it appears that Williams proved very effective at positioning itself in forward power trading to take advantage of "volatility" in the California markets. An e-mail from Andrew Sunderman to Keith Bailey, Bill Hobbs, and Steve Malcolm, all of Williams, was sent on 4/11/01 entitled "California Statistics." It shows that Williams Energy Trading Company made $85 million in gas and electric power cash trading in 2000, but its gain in forward trading was over $1 billion. (Exh. No. CA-30 at 2)

III. EVIDENCE CONCERNING MULTI-SELLER ANTICOMPETITIVE CONDUCT

Q. What types of multi-seller conduct do you discuss in this section?

A. I discuss evidence concerning coordination among sellers. Coordination is a broad term applying to any systematic practice sellers engage in to alter prices or quantities so as to lessen competition based on the pricing or sales actions of their competitors. Collusion is a particularly strong form of coordination usually associated with an explicit agreement to set prices or allowed levels of sales.

Q. From the economic standpoint, what is the difference between unilateral or single-seller uncoordinated withholding and withholding coordinated among more than one seller?

A. A withholding of supply or market manipulation that is coordinated among more than one seller has a different interpretation in economics than does unilateral market power. When a single firm attempts to exercise market power without the active or tacit cooperation of any of its competitors, in order to promote effective competition it is necessary to examine such market power exercise further to determine whether it did or did not realistically promote economic efficiency and other objectives.

When withholding or manipulation occurs through coordinated seller actions there is generally no need to further examine the situation to distinguish between pro and anti-competitive conduct. There is virtually no efficiency justification for allowing two competitors to *collectively* withhold output or manipulate markets.

Q. Have the California parties discovered evidence that California generation sellers may have coordinated their supply practices during this period?

A. Yes, they have. There are two distinct bodies of relevant evidence discovered by the CA parties. The first are a set of two-party agreements between sellers – usually one utility and one power marketer – explicitly designed to enable manipulative trading strategies such as "Fat Boy." Along with communications between the two parties to these agreements also obtained in discovery, and additional information already developed by the Commission in Dockets such as EL02-113-000, this evidence makes it clear that at

least some of these agreements were intended and used to engage in manipulation strategies of the kinds described in Part B below.

The second body of evidence concerns a variety of information-sharing channels that had all the ingredients needed to facilitate coordination of bidding, withholding and other pricing practices among sellers. These information-sharing practices are of particular concern when combined with other conditions of the CA markets that facilitated the profitable exercise of market power.

Q. What evidence have you found of two-party contracts intended to enable manipulative trading practices?

A. The CA parties have discovered a number of contracts between power marketers operating in the CA markets and load-serving or generation entities. Some of these agreements have been identified by Commission Staff in other public proceedings such as Docket No. EL02-113-000 (Exh. No. CA-105 at 498). According to Staff, Enron had agreements with Powerex, Glendale, Pasadena, Energy West, El Paso Electric (Exh. No. CA-105, at 43), Montana Power (Exh. No. CA-90), Puget Sound, the Colorado River Commission, Las Vegas Cogen, Avista, CFE, and Valley Electric (Exh. No. CA-32).

Staff concluded that, through these contracts, Enron gained effective control over 3,500 MW of capacity for potential use in trading schemes, as well as parking rights and other benefits. (Exh. No. CA-105 at 498) (They also apparently gained valuable information, which will be discussed in the next subsection).

The most comprehensive of the contracts uncovered in discovery was Enron's agreement with Glendale, which Enron referred to somewhat imprecisely as a "joint venture" (Exh. No. CA-105 at 497 and Exh. No. CA-169). The contract essentially makes Enron Glendale's scheduling coordinator for sales of Glendale's surplus power into the ISO or PX markets. Revenues from such sales were split 75% Glendale, 25% Enron.

By itself, this contract does not evidence any intent to jointly engage in strategies that are manipulative. However, further documents discovered from Glendale show that Glendale trained its traders (by quizzing them) to undertake the Fat Boy strategies (Exh. No. CA-

170 at 1 to 6) and referred to their agreement with Enron as the basis for using these strategies. The document (Exh. No. CA-171 at 2), produced by Glendale, refers to the Fat Boy strategy, clearly explaining the strategy as well as the two-party cooperation needed to effectuate it:

> ***Fat Boy:***
> *Enron will call Glendale on a day ahead or hour ahead basis to communicate desirable hours in which to sell into California (ISO). Glendale will inform Enron of a volume and an estimate of its cost basis so as to allow Enron to meet California (ISO) scheduling timetable. This estimate will get finalized when Glendale actually purchases or generates the energy. Scheduling timetable is as follows:*
>
> *Enron needs to enter California (ISO) schedules 2 hours prior to energy flow. For example, Enron needs to schedule HE 12 by HE 9.*
>
> *This product is intended to capture a spread between the southwest bilateral market and the California (ISO real time market. Glendale contributes its long term relationships and system capabilities while Enron contributes its California (ISO) expertise and load. The value sharing equation is as follows:*
>
> *Profit.Loss=Ex Post Price-Cost Basis-ISO Line Losses.*
>
> *Any profit or loss is equally allocated to Glendale and Enron. The Cost Basis is refunded to Glendale and the line losses are passed through to the ISO.*[13]

In a deposition in this proceeding, Glendale power trader Jack Dolan also discussed Glendale's participation in Fat Boy-type transactions (Exh. No. CA-167 at 7-12).

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[13] Exh. No. CA-170, at 7 (emphasis in original).

In July 2000, Glendale entered into a new scheduling agreement with Coral, replacing the Enron contract. This document has also been produced in discovery (Exh. No. CA-118). Like the Enron agreement, this contract is on its face an agreement to allow Coral to act as Glendale's SC in the PX and ISO markets. Again, however, additional documents shed light on the intent of the parties to use manipulation strategies. Glendale produced a list of trading strategies that includes "phantom ancillary services," describing a Get Shorty-style trade, as well as a Death Star-type trade (called "RT congestion strategies").[14]

Other discovery suggests that Enron collaborated on these strategies with many of its contractual counterparties (see Table E-4 of Exh. No CA-2, Appendix E). A February 17, 2000 Enron memo (Exh. No. CA-145 at 409) reviews Enron's joint trading activities with Glendale, El Paso Electric, Valley Electric, LADWP, and Redding. Not all of the activities mentioned in the memo are manipulative trades but the entry on El Paso Electric notes that this utility is ready to resume doing "Fat Boy" strategies. An email from Enron employee Geir Solberg dated December 12, 2000 notes that "I made a new fatboy sheet that should fit all our customers profiles." This suggests Enron may have systematically planned to carry out this particular strategy with its "customers." (Exh. No. CA-145 at 1353) An April 6 email from discusses the fact that the NCPA is now again ready to do a buy-resell transaction that appears to enable a load shift. (Exh. No. CA-145 at 1353)

In summary, Glendale's two contracts with Enron and Coral appear to have been used to knowingly pursue some manipulative strategies. Furthermore, it is likely that Enron used its contractual relations systematically to engage in trading strategies that some of its long-term contractual partners knew about.

Q. What about the other two-party contracts discovered by the CA Parties?

[14] I note that, in his deposition, Mr. Dolan claimed that this document was created by Coral (though it was produced by Glendale) and that he claims that Glendale did not know that Coral was engaging in these strategies. I also note that my analysis in Part B of this testimony indicates that Enron and Coral were engaging in Get Shorty and Fat-Boy type trades during the time these agreements were in effect. Within the available time I have not been able to verify for each specific instance in which Enron or Coral potentially engaged in such a trade whether Glendale's resources were used in that particular instance.

A. The remainder of the discovered contracts are parking, transmission use, or other agreements of varying length and specificity. The parking agreements discovered include Sempra-EWEB (Exh. No. CA-68), PNM with many entities (Exh. No. CA-187) including Sempra (Exh. Nos. CA-69, CA-70, and CA-72), Avista-Chelan (Exh. No. CA-100), Avista-Riverside (Exh. No. CA-103) and Avista-Turlock Irrigation District ("TID") (Exh. No. CA-104). A draft agreement between LADWP and Powerex (Exh. No. CA-81) is referenced in an email, a Coral-Colton agreement only in a few spreadsheets (Exh. No. CA-119) and an NCPA-Enron transmission use agreement (Exh. No. CA-86) is evidenced only by a term-sheet.

Although many of these could have been, and likely were used to facilitate joint use of manipulative strategies, these documents alone are generally not sufficient to draw such conclusions. However, four of these agreements raise serious concerns on their face.

First, the Avista-Riverside agreement calls for extensive sharing of competitive information:

> *Information Sharing. The Parties agree that a material benefit of the Agreement, and a part of the consideration for their mutual performance, is the sharing of information. The Parties shall provide to each other market price information and generation availability information, including without limitation, RT market information and RT generation availability information within the Western Systems Coordinating Council area, as such information changes from time to time. RPU shall provide to Avista a complete listing of RPU's electric system obligations and electric system resources, including without limitation, all contracts, agreements, and other information pertaining to RPU's resources, RPU's system requirements, load forecasts, market prices and RPU's Pre-Schedule transactions. (Exh. No. CA-103 at 22)*

Of even greater concern, another section of this contract appears to both acknowledge that the two firms entering into the agreement are competitors and then creates a non-compete agreement between them for retail customers:

> *Right to Compete. The Parties acknowledge that each is a competitive provider of Electric Power in the Western United States, and each is likely to be a competitor for Electric Power transactions. This Agreement is not intended to limit the right of either Party to compete with the other Party to purchase or sell Electric Power, electric transmission services, or AS to any person, including any person with whom a Party negotiates or executes agreements for the purchase or sale of said Electric Power products or services. Each Party agrees that it shall not compete to provide Electric Power products or services to the other Party's existing retail customers.* (Exh. No. CA-103 at 23)

This language raises exceedingly serious antitrust concerns.

A second agreement that raises similar concerns is labeled an "Exclusive Transmission Strategy Agreement" between Avista and the Turlock Irrigation District (TID) (Exh. No. CA-104). This agreement contains the following provisions:

> *The parties are committed and agree to implement strategies mutually developed pursuant to this agreement to optimize the agreed upon TID transmission assets.*
>
> Strategic Collaboration. The TID representative(s) shall be allowed to participate in conferences with Avista personnel where market information and strategies for the joint activities of the Parties are discussed.
>
> Market Information. Through ongoing communication with TID, Avista shall provide market pricing and other market information.

These provisions indicate, at minimum, an extreme potential for coordinated behavior.

A third agreement that raises concerns is a marketing agreement between Sempra and Coral dated February 5, 2001. This agreement gives Coral advanced information from Sempra about the status of the El Dorado plant. (Exh. No. CA-120 at 2)

A fourth agreement that raises concerns is a marketing agreement between Sempra and Coral dated February 5, 2001. This agreement gives Coral advanced information from Sempra about the status of the El Dorado plant. (Exh. No. CA-210 at 2)

Q. Do trader conversations provide evidence of sharing of competitive information?

A. Yes. I have reviewed transcripts of a number of conversations in which traders discuss the status of their power plants or pricing strategies. As one example, the following transcript of conversations between traders for Xcel energy and Mirant (formerly SCEM) were released by Xcel in its Docket No. PA02-02-000. This conversation appears to contain an agreement to overschedule load and vaguely refers to congestion games:

> *SCEM: I like it okay. Yeah. Um, it's working out all right so far. And, uh, I hope it will work out even better this afternoon. You want to try to get something going?*
> *PSCo: Yeah.*
> *SCEM: You want to do an ex-post type of game or you want to do a congestion type of game plus ex-post or um ...*
> *PSCo: Either/or. Maybe we can*
> *SCEM: Either or.*
> *PSCo: Okay. It doesn't matter. We can figure something out.*
> *SCEM: How about, um, let's see, I don't want to crush the market too bad. How about if we try to do a total of 50.*
> *PSCo: Mkay.*
> *SCEM: 25 of it we'll keep in SP15; and 25 of it we'll shoot up north to NP. Um, and try to benefit from trying to relieving some of that Path 26 congestion.*
> *PSCo: M'kay.*
> *SCEM: Does that sound all right? And, um, I don't know how we're gonna split the money up, yet.*

PSCo: We'll figure it out. What hours?
SCEM: Um .....14-19? Pacific?
PSCo: 14-19 Pacific. Hey, Mark (offline - 15-20, uh, let's take that contract stuff that we just picked up ... for 15-20 our time let's take that contract stuff that we just picked up and on 20 all first system and move it to, uh, move it to Four Corners and let Southern over schedule load 25 of it SP and 25 of it to NP for a congestion play....
SCEM: Okay.
PSCo: We put that in.
SCEM: How should we work the money out?
...
SCEM: Um, obviously it's going to get kinda messy starting playing that congestion and all and it's not that messy, really.
PSCo: It ain't that bad.
SCEM: Um, um, I don't know ..... some kind of..... probably be simplest to do some kind of split upside.
PSCo: Yeah
(Exh. No. CA-204 at 27 to 28)

Another transcript of a conversation between two traders, who, I have been informed are employees of Reliant and Mirant, shows the Mirant trader probing the Reliant trader for information on the Etiwanda and Mandalay plants. Noting that this conversation took place immediately following the Reliant withholding episode on June 20-21, 2000, it is particularly important that the Mirant trader asks the Reliant trader what they were doing in the past two days. The Reliant trader replies that they "kind of tested the sensitivity" (Exh. No. CA-194 at 4) of the market (noting also that they bought from the PX as well as withheld supply). The two traders also discuss what Dynegy had just bought and the price at which it was bought, namely balance of month SP15 for $180/MWh (Exh. No. CA-194 at 4).

A final example discovered in a transcript between Reliant and an unidentified counter party illustrates joint bidding behavior (Exh. No. CA-239). Evidently, the counter party wanted to sell at the PX price, but did not want to ensure the sale was made by submitting a price taker bid to the PX. (Note that the transcript mistakenly

transcribes this as a price "ticker".) They expressed their view to Reliant that such a bid may "make the [PX] price power". Instead, the counter party wanted to sell to Reliant at a price to be determined ex-post as the PX price less $0.25 with the understanding that Reliant would bid the power into the PX.

Q. What is the general basis for your concerns regarding the second body of evidence, information channels that facilitate coordination?

A. Electric power markets in general are susceptible to the exercise of market power and manipulation because electricity is a commodity that cannot be stored, and whose demand is ultimately very inelastic. Among power markets, the structure of the CA system was more vulnerable than usual. At least three factors account for this. First, the market was somewhat concentrated, with five major suppliers controlling the majority of in-state independent generation. Second, the competitive processes in the CA markets were repeated auctions involving many of the same participants day after day. Repeat auctions for sale of the same homogenous goods among the same participants often allow bidders to learn how their competitors will respond to price increases and decreases, enabling them to raise or lower prices and quantities with higher expected profits and lower risks.

Finally, the costs and capacities of many sellers were widely known to each other, at least approximately, because such information had been public for many years prior to the onset of the CA markets. Although plants may have been expanded or altered, there are many ways by which rivals can find out the capacity of rival sellers, and capacity expansions are a lengthy and relatively public process.

All these factors made the CA markets especially vulnerable to the use of competitive information for withholding or manipulation behaviors. Indeed, these concerns have frequently led the Commission to prevent the immediate publication of rival generators' bids to centralized power markets, instead delaying the release of these bids by six months or more. The antitrust agencies also have generally opposed release of contemporaneous competitive information in power markets.

Quite recently, in connection with the Commission's investigation of the trading relationship between Enron and El Paso Electric, staff witness Deters expressed deep concern over the misuse of competitive information in power markets via trading agreements:

> *Electricity is a commodity which cannot be stored and thus must be produced at the exact moment of consumption. This in conjunction with electricity having no practical substitute makes it a commodity particularly susceptible to real time market manipulation and the exercise of market power. Alliances and trading of information could transform what appears to be a marketplace of several independent competitors into a set of entities, either wittingly or not, with aligned interests in maximizing profits.*[15]

Q. Have the CA parties uncovered evidence that contemporaneous competitive information on Western power markets was shared among sellers in these markets?

A. Yes, they have. The first information channel that raises concerns was a commercial information service that published, on a subscription basis, the daily outages of power plants in the West. This information service, Industrial Information Resources (IIR), sent daily email updates of plant outages to a group of subscribers. This information sometimes included prospective as well as current plant outages and was often highly specific, providing the expected start and end dates for the outage of each specific generating unit as well as the cause of the outage. (Exh. Nos. CA-95 and CA-97). The cost of the service was approximately $70,000/year to a subscriber (Exh. No. CA-96).

In addition, subscribers to IIR could email the service and request immediate information on outages of a competitor's plant. IIR would then apparently call personnel at the competitor's plant and report back to the subscriber requesting the information. This information was then sometimes shared among the subscriber's traders. For example, Duke's principal contact person with IIR regarding generation outage information in the west was Duke trader James Stebbins. When Mr. Stebbins received outage information

[15] Exh. No. CA-105 at 39 (emphasis added).

from IIR he would send an e-mail to roughly fifteen other Duke traders sharing the information and state that the information had come from "the mole." As he stated in one e-mail:

> *I just heard from the mole. He is reporting that the PV3 will be coming back on line 6 days earlier than expected. The new return date is March 3. Good luck and happy selling.*[16]

Duke stated in response to a CA parties' data request that "the mole" was "a nickname for Industrial Information Resources, Inc."[17]

Q. Did IIR get all of its outage information from personnel at the plant subject to the outage?

A. Yes, according to IIR. IIR's emails back to subscribers requesting information on plant outages often contain the phrase "according to the plants" or "I talked to the plant." In response to a Commission Subpoena issued at the request of the CA parties, IIR said:

> *CAL-IIR-4. Please state whether, during the relevant time period [January 1, 2000-June 20, 2001], all the information you provided to clients and subscribers of your Outage Database Service regarding plant outages was either obtain from or confirmed by personnel at the generating plant subject to the outage.*
>
> *RESPONSE: During the relevant time period, all of the information released by Industrial Information Resources Inc. was confirmed by someone at the plant level. While we do not keep track of who specifically informs us of or confirms a specific outage, we never release any data, either in the power market segment of otherwise, without independent verification from someone at the plant."*[18]

Q. Could IIR's subscribers simply have called their competitors' plants themselves to inquire about outages rather than paying IIR?

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16 Exh. No. CA-95 at 3.
17 Exh. No. CA-253.
18 Exh. No. CA-98.

A. Power companies should recognize that discussing plant outages with competitors could raise antitrust concerns and should have rules or guidelines that should prohibit such communications. Williams' market analyst Brian Skinner, who acted as a contact person for Williams with IIR, testified in a deposition that Williams' antitrust training included instruction that personnel are not to discuss competitive information with other companies.[19] Mr. Stebbins, of Duke, similarly testified that Duke's code of conduct prohibits employee contacts with competitors regarding plant outages because it is market-sensitive information.[20] Nonetheless, these same companies would regularly receive plant outage information provided by their competitors using IIR as an intermediary.

Q. Who were IIR's subscribers?

A. IIR's response to the subpoena identified three of the Big Five as subscribers: Duke, Dynegy and Williams. In addition, IIR identified the following subscribers active in Western power markets during some portion of the May 2000 through June 2001 period: New Energy Ventures, AEP, Cinergy, Cargill, Enron, Koch, El Paso Energy, Aquila, Avista, Merrill Lynch/Allegheny, Coral Energy, Hafslund Energy, PacifiCorp, and Pinnacle West.[21]

Q. Did the generators that subscribe to IIR know that IIR was providing their competitors with outage information from their own generating units provided by their own personnel?

A. They must have. IIR stated in response to the subpoena that it provided the same daily updates to all of its subscribers in the west,[22] and that all of its subscribers were aware that it obtained all of its outage information from personnel at the plant:

> *CAL-IIR-7. Please state whether IIR advised clients subscribing to IIR's Outage Database Service that the outage information provided is obtained from or confirmed by personnel at the generating facility subject to the outage.*

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19 Exh. No. CA-20 at 15 to16.
20 Exh. No. CA-252 at 33 to 34.
21 Exh. No. CA-98.
22 Exh. No. CA-98 at 10 to 11..

RESPONSE: All clients should have been and should be aware of the methodology used by Industrial Information Resources Inc. in generating the data that we provide. The fact that we are a primary market research firm that verified all of our information at the plant level is a big selling point for our services and is well documented in our literature and promotional materials.

IIR further provided to the CA parties, pursuant to the subpoena, the actual outage data it provided to its subscribers in the west during the relevant period in its daily e-mail updates. Outages of the California generating units of Duke, Dynegy and Williams appear frequently on those reports. These companies therefore knew, from seeing the reports, that their own outages were being reported to all competitors that subscribed to the service -- a service that Mr. Skinner testified was understood to be widely used in the industry as a source of outage information. IIR's report was not customized – the same report was sent to all subscribers, and subscribers should have known this. Second, when subscribers' own plants had outages, these would have shown up on their subscription report. Third, IIR maintained (as it did in the interrogatory response above) that it consistently relied on information from plant personnel.

Q. What evidence is there that sellers used the IIR information in their bidding, pricing, and withholding strategies?

A. Section II of my testimony explains how outages are one form of withholding that is likely to impact prices where suppliers are pivotal. Pivotal suppliers who are observing each others' outages in near-RT have an ideal means of gauging their pricing response to that outage. In most cases, pivotal suppliers' reaction to the outage would be to increase their own prices. Thus, through the information-sharing mechanism of IIR subscriptions, a single unintended or intended outage could serve a signal to other pivotal suppliers to raise bids or withdraw additional capacity.

In depositions, Mr. Skinner of Williams and Mr. Stebbins of Duke discussed their use of generation outage data in formulating pricing strategies. Mr. Skinner's agreed that the outage information provided by IIR helped traders determine what price they should charge for energy during the outage and whether not to sell energy

during a particular period or in a particular location.[23] He further agreed that knowledge about outages reduced trading risks.[24] As Mr. Skinner testified:

> *Q. So knowing that an outage of a generating plant is expected forecast, could assist a seller in deciding the price that they should charge for electric energy during that period for example. Would that be correct?*
> *A. I would agree with that conclusion, yes.*[25]

Similarly, Mr. Stebbins agreed in his deposition (Exh. No. CA-252 at 46 to 47) that it was "possible" that outage information would have a significant impact on prices bid.

Q. Were there other information channels of concern in this market?

A. Yes, there were several. First, it is possible that traders used any of the online price-reporting services to observe prices. Second, during part of this period the WSCC was posting the status of transmission lines around the West. The CAISO and others believed that this information, available to WSCC members, showed RT transmission outages and facilitated manipulative trading practices. In response to CAISO complaints, the WSCC removed this information.

Finally, the contracts discussed in the previous subsection were themselves sources of information on potential rivals' resources. FERC Staff witness James Ballard made this point in his testimony in Docket No. EL02-113-000 concerning Enron's trading agreement with EPE:

> *Far outweighing the contract related profits that Enron realized from the agreement, Enron valued the generation information that it obtained from EPE. As stated in an earlier section of this testimony, EPE owns a 15.4% share of Palo Verde units 1, 2 and 3, and a 7% share of units 4 and 5 of the Four Corners plants. To the extent that Enron learned about the*

[23] Exh. No. CA-20 at 7 to 8.
[24] Exh. No. CA-20 at 9.
[25] Exh. No. CA-20 at 8.

> *plant operational limitations that affected EPE's ability to serve its own load and market excess generation, Enron could also deduce that the balance of the units owned by others were likewise affected. In addition to the fact that these plants constitute major trading hubs for electric energy in the western market, their operational availability also has impacts on the ability of the transmission system to transfer electric power in the western market.*[26]

The extensive information-sharing provisions of the Avista-TID contract, described in the subsection above, also support this concern.

Q. What is your conclusion regarding coordination among sellers of power to the CA markets?

A. There is substantial evidence that sellers entered into agreements that contemplated manipulative trading strategies, and that they appeared to conduct these strategies under the agreements. There are also many instances of sellers openly discussing the joint execution of these strategies. The Commission's proceedings concerning El Paso Electric and Enron[27] are consistent with this conclusion.

In a market that was highly vulnerable to market power exercise and manipulation, there is also significant evidence that some sellers had access to special information that facilitated coordination. Within the limited time frame afforded by the Commission to conduct discovery I could not fully explore the extent or impact of coordinative behavior. However, the evidence is consistent with and supports my general conclusion that prices throughout the period were inflated to levels beyond those that would have existed in a competitive market, and also warrants a much more thorough examination of coordination in these markets during this time period.

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[26] Exh. No. CA-105 at 488.
[27] Exh. No. CA-105 at 172.

IV. SCARCITY RENTS AND MARKET FUNDAMENTALS

Q. Please define scarcity rents and "market fundamentals" as you use the terms in this testimony.

A. Scarcity rents are the difference between the price a seller receives for a product and that seller's short-run marginal cost of producing the product. In the CA electric power markets, it was the difference between the price received by the seller (usually the MCP) and the incremental cost of that seller's generation or purchase of the power sold.[28]

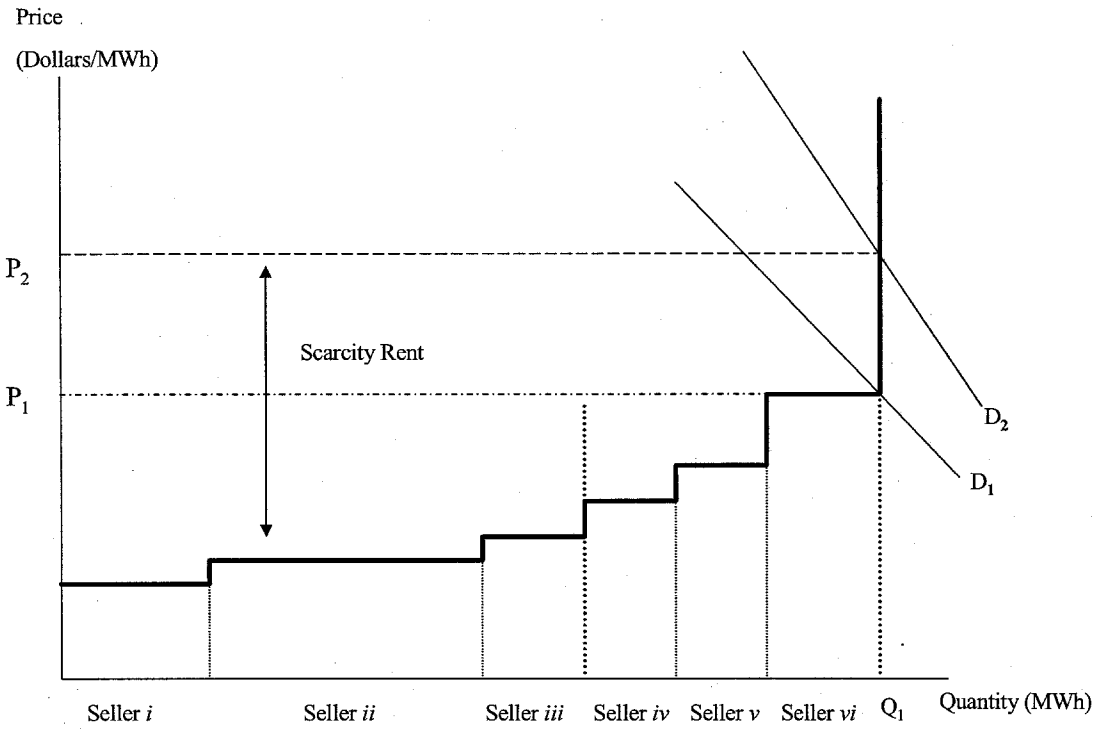
"Market fundamentals" is a somewhat vague term. As I use it here, I mean the major factors that determine the aggregate supply and demand in any well-defined power market that are strictly outside the short-term control of the sellers in that market, individually or collectively. For example, the supply of water for hydropower and the aggregate demand for power are both outside sellers' control. In well-functioning markets, the cost of most production inputs is outside producers' control as well.

Although I use the term in this discussion, I acknowledge that "scarcity" can be a somewhat abstract concept. Thinking in terms of supply and demand curves in a market, scarcity can also be visualized as a situation in which the demand curve has shifted out (higher demand) and the supply curve did not change. As Figure 9 illustrates with the difference between P2 and P1, this temporarily raises price because overall supply is smaller relative to the new higher level of demand. Notice, however, that supply has not declined, and no supplier is withholding or bidding above marginal cost in this figure – it is simply the fact that demand growth has outstripped supply increases.

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[28] Note that this definition of scarcity rents also implies that different levels of scarcity rents will be realized by sellers with different incremental generation costs.

Figure 9
Scarcity Rents with No Generator Withholding



Q. Is the cost of natural gas used by power generators a "market fundamental," since natural gas is an important input to power generators?

A. Natural gas is certainly a key input to power generation in Western power markets. If it could be shown that the price of natural gas was outside the control of power sellers in this region it would fit my definition of a market fundamental. However, there is evidence that power trading companies and/or affiliates of power generators manipulated the price of natural gas, as discussed in the testimony of CA Parties witness Michael Harris. A Commission proceeding has also already found that affiliates of El Paso Natural Gas, which also sells power, exercised market power over natural gas deliveries to the southern CA markets. Thus, the price of natural gas must be treated as a special case, not as a justification for high power prices that was entirely outside power sellers' control.

Q. What is the relevance of scarcity rents to this proceeding?

A. The economic fundamentals in a market can change so as to create true scarcity. For example, an unforeseen burst of economic activity can create demand for a product faster than new supply is created. This change in the economic fundamentals would lead to the creation of scarcity rents, *i.e.*, to prices higher than marginal costs for some producers, until new supply was created and the market came back into balance.

Scarcity rents play an important role in all competitive markets. Margins higher than the variable cost of production signal that more capacity may be needed, and they help create incentives and ultimately pay for the cost of new capacity additions.

It has been argued at times that the price increases that occurred in the CA markets in 2000-2001 were solely the result of changes in market fundamentals. These scarcity rents, it is argued, are needed to serve as signals to build more generation capacity.

Q. What is your response to this argument?

A. This argument is deceptive because it attempts to turn two half-truths into two whole truths. These half-truths are (1) prices are high only because of true scarcity; (2) the resulting high prices are necessary to provide incentives to build more capacity.

Q. Why do you call the first point a "half truth?"

A. The first deceptive half truth is the assertion that if true scarcity exists observed prices must the result of only this scarcity and no economically harmful conduct. This argument is valid only if the degree of scarcity caused by economic fundamentals, and the response of sellers to this scarcity, remains within the boundaries of workable competition. In the CA markets, the behavior documented in this filing of the CA parties shows that it did not.

It is important to understand that, in power markets, high levels of true scarcity create the incentive and ability for many sellers to take advantage of this by exercising market power and manipulating the market. In effect, the true scarcity enables the conditions that allows sellers to create and profit from much higher levels of artificially-induced scarcity. The fact that conditions led to a certain amount of

true scarcity therefore does not lead to the conclusion that whatever high prices are observed must be due to the true scarcity. Indeed, the conclusion is the converse. Because real scarcity enables and creates incentives for sellers to exercise market power by withholding supplies and other means of price manipulation, when scarcity becomes very high it is common to control (*i.e.*, regulate) prices or seller behavior in some fashion.

Q. Can you illustrate how true scarcity enables and creates incentives to exercise withholding behavior?

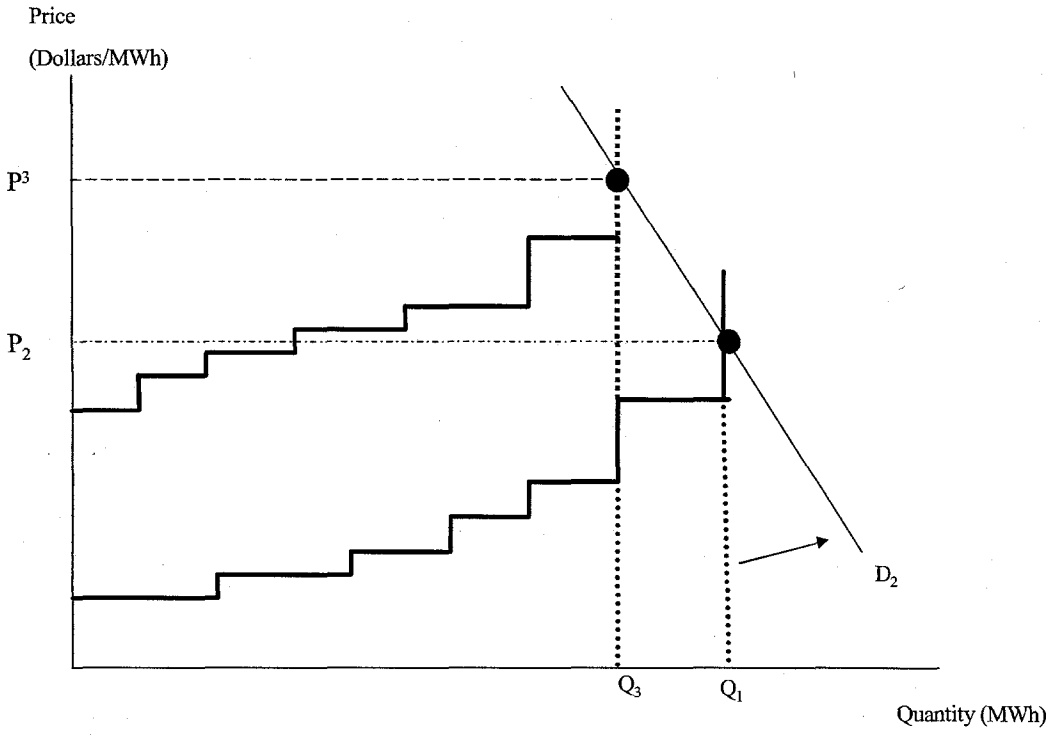
A. Consider what occurs as the magnitude and duration of scarcity rents increases in a market with a limited number of sellers. Figure 10 is the same as Figure 9 except that we assume there are six sellers, each owning one horizontal portion of the supply curve. Six sellers is a moderately concentrated market, but we initially assume that no seller is withholding and that the increase in demand raises price from P1 to P2, as in Figure 9

Suppose now that the scarcity shortage lasts longer, but still within the time before new suppliers enter. It should not take long for the six sellers in this market to figure out the following:

- Every bit of their capacity is being demanded (and more);
- No one else has any capacity to sell until new supply is built; and
- Demand is fairly inelastic.

Under these conditions, every one of the six sellers who is able to raise their price (*i.e.*, whoever did not sell its output under fixed-priced contracts prior to the scarcity episode) should realize that he has the incentive and ability to raise price still further by withholding or threatening to withhold even a small portion of capacity. Even though we would not say that this market is structurally concentrated because it has six major sellers, any seller who has not locked in its sales price is a pivotal supplier and has market power. The likelihood that sellers would be willing and able to charge prices well above competitive levels is shown in Figure 10 by a supply curve that rises and shifts left relative to the marginal cost line until it intersects the demand at a very high price P3.

Figure 10
Scarcity Rent Example



There are many ways suppliers facing the shortages in Figure 11 can determine that they have the power to increase prices. They may test the market by unilaterally raising up their price, *i.e.,* economic withholding. They may also begin limiting quantities sold very slightly – only a small withdrawal is needed to raise price significantly. Other suppliers with access to price and supply observations may see this behavior and copy it, raising price even more. Then net effect of the increase in price bids and withholdings of supply is illustrated by the upper supply curve in Figure 11.

Without active seller coordination, this sort of pricing behavior is generally referred to as tacit collusion. It is essentially the same behavior that widely established models of oligopoly behavior, such as Cournot-Nash and supply function equilibria models, are designed to explain. Note however, that this difference between P2 and P3 is not due to true scarcity, but rather to the exercise of market power.

Economists who have studied tacit collusion have noted that industries with firm capacity limits are inherently suited to enabling oligopoly

pricing. Long before he became involved in the California ISO Market Surveillance Committee, Professor Frank Wolak and co-author Robert Staiger examined the relation between oligopoly pricing and capacity constraints in generalized industries. They found that the tendency towards this pricing were larger where capacity constraints are firm and demand approaches production limits:

> *"However, as demand strengthens further, capacity constraints begin to play a role; over this range, the stronger demand is, the closer colluding firms will operate to capacity and the smaller the current gain from defection will be, strengthening the ability to maintain a higher collusive price in such periods."*[29]

In most industries, the limits on production capacity are not as absolute in the short run as in the power industry. In addition, the delays in adding new generating capacity are also longer than in many other industries. Finally, as the FERC and others have often noted, demand is very inelastic in the short run. Thus, the technical attributes of the power industry and other characteristics create the ideal conditions for profitable oligopoly pricing without the need for obvious unilateral or coordinated withholding.

The implications of this finding are significant. Under certain conditions, high and enduring physical scarcity moderately concentrated among some producers virtually ensures that these sellers have the ability and incentive to withhold capacity profitably. Extremely high and persistent "scarcity rents," indicative of a prolonged physical shortage, also indicate that the conditions for profitable withholding and manipulation, individually or collectively, are very strong.

Of course, it is necessary for the scarcity to be real (or perceived by buyers to be real) and that limited opportunities arise for buyers to substitute other goods. It is also necessary that suppliers benefit from higher prices and that they have the information to gauge prices and quantities in the market to calibrate their strategies. Finally, it is necessary that the true supply be concentrated among a fairly small number of sellers, as this makes price increases easier to coordinate.

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[29] Staiger, Robert W. and Frank A. Wolak., "Collusive Pricing with Capacity Constraints in the Presence of Demand Uncertainty," Rand Journal of Economics, Summer 1992, 23(2): 203-220.

In summary, the attributes of the power industry mean that a prolonged scarcity of supply enables supra-competitive pricing to occur and be profitable.

Q. Your point here is that, in electric power markets, true scarcity creates the incentive and ability for suppliers to exercise market power, withhold output, and manipulate prices. How does this relate to the specific findings concerning withholding and manipulative trading practices identified by the CA parties in this proceeding?

A. The identification of widespread withholding and manipulative trading is a definite sign that prices increased past the point of true scarcity rents that merely send pro-efficient market signals to new entrants. Power markets all over the world have frequent periods in which they yield scarcity rents to sellers, but no power market in history led to price increases as large and sustained as did the Western power markets in 2000-2001.

Q. You also referred to a second "deceptive half-truth" embedded in the assertion that Western power prices were explained by true scarcity in 2000-2001. What is this?

A. The second half-truth in this assertion is that ever-increasing prices due scarcity, with no limit, properly incentivize ever-greater levels of new supply. Thus – according to this half-truth – any control of prices would destroy the economic incentive to add capacity.

The more complete and correct version of this point is that true scarcity rents send reasonable signals that new suppliers act on. Extraordinarily high price levels are a sign of trouble in a market and do not encourage further investment. Most observers know that extraordinarily high price levels come from a combination of true and artificial scarcity, as explained above. They know that when the artificial scarcity is controlled prices will fall, and when new supply is added prices will fall further. Extremely high levels of artificial scarcity creates prices that only achieve transfer wealth from consumers to suppliers and create overall losses to society.

This point can be illustrated with a simple example. Suppose that a tornado destroys much of a city in the middle of a desert, including every source of water except one. New water supplies can be built, but

this will take one month. There is only enough water from this source to serve the town's needs for a month if it is rationed to all citizens.

In this example, the original scarcity was not even caused by any supplier. If we apply the specious reasoning that water prices in this town should simply reflect scarcity, the sole remaining supplier of water would simply be able to exercise market power raise price until the "market" for water cleared. This would result in the very wealthy members of the town owning most of the water and very high water prices. However, it is doubtful that these high prices would motivate new water suppliers to add any more supplies than they would otherwise add. These suppliers would also know that the high prices observed were not a good signal for investment because they were distorted by the unusual amount of scarcity.

Note, however, that this simple example does not suggest that the Commission's pricing or mitigation policies in competitive markets should remove true scarcity signals. This would defeat competition. Instead, what is suggests is that if the Commission wants to keep prices within the bounds of what workably competitive markets provide, it cannot conclude that prices were appropriate in a market simply because scarcity existed. It must factor into account the behavior of sellers and the impact of this behavior on the market.

Vulernablity of Multi-Day OOM and Exchanges to Withholding and Manipulation

Q. In the prior section, you discussed the structure of the CA markets and strategies for withholding and shifting power profitably between the DA and RT markets. In this section, you explain why severe scarcity and market fundamentals alone cannot be a defense for high prices when additional market power is enabled. Do these points apply only to transactions in the CA markets lasting one hour or one day?

A. No, they do not. If market power can be profitably exercised via any of the means discussed in Sections II and III, there is no economic reason why it cannot be exercised over transactions lasting more than one day. Indeed, one well-known strategy for exercising market power is to force buyers to purchase bundles of commodities that include some of the good over which market power is strongest and some of another good

for which there is less market power. By charging higher prices for the bundled good than buyers would pay for such goods purchased on a stand-alone basis, the seller earns some of the supracompetitive rents from the sale of the bundled (also known as tied) good.

For example, an email from Duke dated December 4, 2000 states "As per Steve, if the ISO wants to call on us for out of market on SBGT they must pay us at least $350 per MW and they must purchase it for a minimum run time of 10 hours for the month of December." (Exh. No. CA-165 at 1.)

Q. Do your economic arguments also apply equally to exchange transactions?

A. Yes, they do. An exchange transaction is one in which one quantity of power is provided to a buyer who then pays for the power by sending a quantity of power back to the seller as payment. The ratio of the power sent back as payment, along with the price of power in the market, sets the effective price of the transaction to the buyer.

There is no economic difference to a buyer between paying for a power purchase in dollars and paying for it in a commodity whose price is well-established in dollars in the marketplace. Indeed, there is little economic difference between denominating a transaction in units of power and denominating it in a foreign currency. The buyer cares about the economic value that must be given to the seller per MWh received, not the specific units that are exchanged, so long as the units are readily convertible to other forms of value.

Q. Do these points mean that there is no economic basis for excluding multi-day or multi-hour transactions or exchanges from calculations of mitigated prices or refunds?

A. Yes, they do. For transactions lasting for several hours or transactions lasting longer than a day (but shorter than the period during which market conditions change substantially through new entry), or transactions denominated in units other than dollars, there is no economic basis for excluding such transactions from mitigation.

V. THE PATTERN OF CONDUCT BY SELLER GROUPS

A. THE RELEVANCE OF PATTERNS OF CONDUCT AND GENERAL OBSERVATIONS

Q. What do you mean by the term "pattern of conduct?"

A. I use this term to refer to the set of suppliers who engaged in each particular form of harmful economic activity, the frequency with which they engaged in the activity or other measures of the magnitude of their activity, and any significant patterns in the dates and times they chose to engage in the activity.

Q. Why are these conduct pattern issues relevant to this proceeding?

A. There are a number of reasons. First, if the California parties had discovered that sellers' harmful activities were rare and isolated instances, the impact of these activities might not have been very large. Similarly, if only one or two "bad apples" was involved in harmful conduct, assigning responsibility for the impacts of this conduct would be relatively easy.

Conversely, if harmful activities were extremely widespread, and involved many sellers, quantifying the impacts of one sellers' conduct becomes essentially impossible. If many sellers are engaging in many forms of harmful conduct at approximately the same time, and influencing each others' behavior, the economic impact of any one sellers' act cannot be divorced from the impacts of other sellers who acted responsively. This is the same point I made at the end of the previous section.

Examining the pattern of conduct also allows the Commission to consider the degree to which seller conduct was uniform, random, or motivated by understandable forces. This, in turn sheds light on whether sellers' conduct was willful or even coordinated.

As an example, suppose that the use of manipulative strategies appeared to be totally random among sellers, showing no relationship to the economic incentives of sellers to use the strategy. It would be reasonable to infer from this pattern that sellers probably were using this strategy without a high degree of intent. On the other hand, if we see that strategies were used often by the seller groups who would be

expected to use them, it is highly unlikely that these sellers were not acting intentionally.

The relationship between sellers' use of withholding and manipulation strategies and changes in market conditions and market rules also helps inform questions of seller motivation and intent. During the 18 months examined by the California parties, the California markets underwent very substantial changes in market conditions, rules, and structure, while the set of sellers in these markets remained virtually unchanged. Differences in the responses of sellers to changes in rules, structure, and market conditions can provide information on sellers' motivations and intent.

Q. Do you have any general observations on sellers' conduct patterns before addressing them in more detail?

A. Yes. Evidence assembled by the CA parties shows that during the Crisis Period, sellers who frequently engaged in withholding or manipulation strategies continued to do so, often altering but not eliminating these practices as rules or conditions changed. When sellers used these strategies they did so extensively. At the same time, not every seller in the market used either withholding or manipulation strategies, as near as we can tell. Most of the major sellers, accounting for most of the power sold in the California markets, used them, but the use was neither universal nor uniform.

Q. What do these observations suggest?

A. These points suggest that sellers did not employ these strategies simply because scarcity and other conditions outside their control forced them to do so, or that they did them because "everyone else was doing them." Many others may have been doing them, but at any one time there were sellers who chose to interpret the rules and their trading responsibilities differently. Of course, these sellers still often benefited from the price inflation caused by the others – and it would be an impossible endeavor to sort out "good" profits from "bad" through any sort of case-by-case or seller-by-seller analysis.

Q. How is your discussion of conduct patterns organized?

A. I first discuss patterns of seller withholding from the DA market prior to the CERS period. I then discuss both seller withholding from RT markets through aggressive bidding and seller withholding through the declaration of false outages prior to the CERS period. Since changes in

the structure of CA short-term energy markets at the start of the CERS period fundamentally changed the ways in which sellers could withhold from those markets, I then separately discuss withholding patterns during the CERS period. I then discuss exports from CA as a means of withholding, both prior to and during the CERS period. Finally, I discuss patterns in the use of manipulative trading strategies during the Crisis Period, and patterns in the sales patterns of the Big Five and other CA generators throughout the Crisis Period.

B. PATTERNS OF SELLER WITHHOLDING PRIOR TO THE CERS PERIOD

Withholding Through the Reduction in Sales to PX Markets

Q. Have you investigated the incentives of sellers to withhold power from the day-ahead market?

A. Yes. In my testimony, I develop a model of supply-side withholding. The main result of the model is that when a seller or seller(s) become pivotal in the RT market, they have an incentive to withhold supply offers from other forward markets, including, in the case of California, the PX's day-ahead market. The intuition is simple, had sellers pre-committed capacity in the forward market, they would not have the ability to exercise market power in the RT market, where the demand for power is typically highly inelastic.

Q. Do you have any evidence that sellers may have behaved in this fashion?

A. Dr. Stern conducts a number of tests to determine whether suppliers withheld power from the PX day-ahead market. He shows that supply bids into the day-ahead market were lower during high-demand and high-price periods. His analysis is conducted for both the entire market and for individual suppliers.

Q. Why is his analysis useful?

A. Because it establishes that supply-side withholding behavior was both significant and widespread during the crisis period. The Commission has to date identified specific instances of withholding. For instance, the Commission has found that Reliant engaged in withholding during June 20-22, 2000. Specific anecdotes are helpful in understanding the

graphic nature of the behavior of certain suppliers. Nevertheless, it is also helpful to understand how widespread this behavior was and the impact that it had on volumes in the RT market and the ability of IOU's to meet their load obligations through forward purchases.

Q. What type of market-level analyses does Dr. Stern perform?

A. Dr. Stern examines the change in the amount of energy offered by suppliers in the PX day-ahead market between the summer of 1999 and 2000. He defines net supply as the difference between the quantity of a supplier's supply and demand bids at a given price.[30]

Dr. Stern finds that there was a growing gap in the amount of supply offered into the day-ahead market in 2000 relative to 1999. The net supply offered into the day-ahead market by suppliers[31] in May of 1999 was roughly equivalent to that of May of 2000. Thereafter, the gap began to grow. In June of 2000, suppliers' net supply offers were roughly 2,000 MW below what they had been in June 1999. In July, the gap widened to roughly 6,000 MW. In August, Dr. Stern's calculations show that the gap was roughly 8,000 MW. The gap fell to about 6,000 MW in September. The reduction in the amount of supply offered into the PX in 2000 relative to 1999 and the resulting rise in volume in RT and OOM markets suggests that suppliers were withholding power from the day-ahead market.

Q. What did Dr. Stern conclude with respect to the pattern of DA withholding among major suppliers?

A. Dr. Stern separately analyzed the net supply bids of the Big Five, Enron, Powerex, and all other non-IOU suppliers during Summer 2000.[32] Using bids in Hour 16 averaged over a month as a benchmark, he found that Big Five PX bidding changed significantly between August 1999

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[30] Many owners of generation issued both supply and demand bids into the PX day-ahead market. His choice of net supply is appropriate given the anectdotal evidence that certain suppliers enhanced their gains from the manipulation of the RT market through the purchase of energy in the day-ahead market. As Dr. Berry notes, Reliant's strategy for John 21-22 involved the withholding of generation and the purchase of energy in the day-ahead market.

[31] Dr. Stern defines sellers as all entities in the California market other than the IOU's and municipal buyers.

[32] These individual-seller net supply curves do not incorporate sales from that supplier that were sold bilaterally and then resold into the PX (which are probably not significant). Also, since they are net supply curves, reductions in net supply might be explained by increases in PX demand by these suppliers scheduled to load. (PX demand that was later resold into the DA market is a ricochet trading strategy, as explained in Section II).

and August 2000. The changes observed are summarized in the following table:

Supplier	Changes in PX Supply Behavior Summer 2000	Changes in PX Supply Behavior 1999 vs. 2000
Duke	stable or increased supply at all price levels	increased 1000-2000 MW
Dynegy	shifted out in July, pulled in low price segments in August, shifted entire curve in during September	except in August, 1000-1500 MW less than in 2000, declining to same at prices below $100/MWh
Mirant	steeper sooner as summer progresses, same ultimate price and quantity	approximately 1500 MW less at high prices, declining to same at prices below $100/MWh
Reliant	"swiveled" from 0 to 800MW to -200 to 1000MW	same or more at high prices
Williams	not a significant supplier to PX after June 99	not significant supplier to PX after June 99
Powerex	shifted to much less supply in August and September	same until August/September then less by a few 100 to 1000 MW
Enron	pivots inward in June and July then shifts in everywhere	same or greater in June/July; approximately 1000 MW in August/September

Generally, this table evidences a qualitative pattern that persists across several types of withholding about to be reviewed. Williams (who here does not even supply to the PX) provides the greatest degree of withdrawals, followed by Dynegy, Mirant, and Reliant in the middle, with Duke providing essentially no comparable behavior the other four.

Q. Could the reduction in supply offers in the day-ahead market be explained by other factors, such as a shift towards bilateral contracting, increased outages in 2000, or operational limits on generating units?

A. Dr. Stern provides strong evidence that this is not the case. Dr. Stern compares the net supply offered into the PX during hour 16, typically the hour with the highest load, with the net supply offers in hours 7 through 10, the early peak period of the day. He finds that in hour 16, the net supply offers into the in August of 2000 were approximately 2,000 MW *lower* than in the early morning hours. Of course, absent withholding, it would be reasonable to expect that supply offers would naturally be higher during peak periods.

Dr. Stern points out that these results are unlikely to be due to bilateral contracts since bilateral contracts typically involve commitments for a block from hour 7 to hour 22. As far as I am aware, there is no reason that planned outages or maintenance would be more common in late

afternoon hours than in mid-morning hours. Finally, limitations on emissions typically concern total emissions or runtime rather than the specific hour of the day that a generator is in operation. Since none of the structural explanations for the reduction in supply during the crisis period apply to the intra-day pattern of supply offers, I find Dr. Stern's intra-day evidence of supply-side withholding persuasive.

Q. Could IOU's have avoided the underscheduling problem by adjusting their bidding strategies?

A. Dr. Stern shows that the maximum amount of supply bid into the PX day-ahead market during the crisis period was simply insufficient to meet load. That is, Dr. Stern compares the amount bid into the PX at $750/MWh, a price that exceeded the cost of production of virtually every unit, with the forecast load of the ISO. He finds that during the crisis period, the amount bid into the PX was simply insufficient to meet load regardless of the shape of buyer's bid curves. Dr. Stern examines the 208 hours during summer 2000 when the ISO declared emergency conditions. He finds that during 201 of these hours insufficient supply was offered to the PX for IOUs to avoid using the ISO RT market for more than 5% if their load. Further, Dr. Stern finds that had the IOU buyers bid a completely inelastic demand curve for the summer 2000 period, in an attempt to avoid use of the ISO RT market, that their net cost increase to serve load would have been $6.7 billion.

Withholding from RT Markets through Aggressive Bidding Behavior

Q. In Section II, you explain sellers' incentives to bid aggressively in RT markets and other forms of RT withholding Is there evidence of widespread aggressive RT economic withholding during the crisis period?

A. Yes, there is overwhelming evidence that most of the generators and other suppliers used aggressive bidding strategies in order to drive up prices in the RT market. The testimonies of Dr. Carolyn Berry and Philip Hanser address different aspects of this behavior, and it is evident in many of the documents uncovered in the discovery process.

Q. What do you mean by "bidding aggressively?"

A. A: I mean that suppliers are bidding in a manner that is inconsistent with competition because bids are far above the underlying costs of generation and can only be intended to drive prices significantly above

competitive levels. Aggressive bidding is one form of economic withholding.

Q. What sort of bidding strategies were observed?

A. In her testimony, Dr. Berry finds that the generators substantially raised or "spiked" the bids for some or all of their generating units on certain days or in certain hours even thought there was no change in underlying costs. Spiked bids were often preceded by periods when the units were not bid into the market at all even though there were available. Several of the large in State generators also used hockey-stick type bidding, which Dr. Berry measures through an index called "average bid span". This difference between the lower and upper end of the bid for a particular generating unit (stated as a monthly average) exceeded $200 per MWh for many units and even exceeded $800 per MWh in December of 2000 for Dynegy's El Segundo 7 Unit 2. (Exh. No. CA-7, Figure 3) Again, this sort of bid pattern can not be justified by cost factors.

Q. How prevalent were these bidding behaviors?

A. Dr. Berry found spiked bids to be very frequent in the summer of 2000, and they were particularly common during emergency periods declared by the ISO. Her Figure 6 shows that Williams, Dynegy, Mirant and Reliant regularly submitted spiked bids during system emergencies, while Figure 7 indicates that such activity occurred less frequently throughout the summer.

Q. Did the importing suppliers also engage in these economic withholding through bidding behaviors?

A. Yes. LADWP, BPA, Powerex, and IdaCorp all engaged in these bidding strategies. Dr. Berry reports that Powerex, which claimed at one point to constitute 70% of the RT market alone, made a regular practice of hockey stick bidding. They also withdrew their power and then entered spiked bids in a manner quite similar to the in state generators during the Summer of 2000. LADWP, which is virtually surrounded by the CAISO, also frequently entered elevated bids during emergency periods.

Q. How can one be sure that the bid spikes observed and documented by Dr. Berry were not the result of changes in costs?

A. Mr. Hanser addresses this issue in detail, but Dr. Berry makes a useful point that I would like to mention before moving on to Mr. Hanser's

work. She notes two points that undercut any argument that costs drove the generators' bids. First she notes that natural gas prices rose over the summer, increasing generator costs. Second, she observes that as price caps fell from $750 to $500 and finally to $250, the units remained in the market at lower and lower bid levels. A plant that could operate profitably under a $250 bid cap, clearly would not need to bid $750 during the earlier part of the year to cover its costs.

Q. What does Mr. Hanser conclude about the relationship between the generators' bidding patterns and their costs?

A. Mr. Hanser demonstrates that bids were not driven by costs, but instead by the generator's ability to profit from price increases and by opportunities provided by tight market conditions. In the early part of his testimony Mr. Hanser compares the bids of the various generators to their marginal generation costs. He demonstrates graphically that for most of the generators average bids far exceeded marginal costs, particularly in the period before the caps were reduced.

The difference is striking. Costs for most of the generators in the early summer were in the range of $50 to $150 per MWh range, while mark-ups over costs ran from about $250 all the way to $700. Mr. Hanser's graphs also second Dr. Berry's observation that bids fell with caps despite rising costs, so there can be little argument that the high, early bids were cost justified. Finally, as I noted above these graphs also show Duke to be somewhat of an exception to the behavior exhibited by the other generators in the period prior to the soft price cap. Duke's bids were far more consistent with their underlying costs than were those of its peers.

Q. Does Mr. Hanser do any more detailed analysis of the motivation for the generators high bids?

A. Yes. His analysis seeks to determine if markups are related to each generator's ability to profit from higher prices or to changing condition in the marketplace. His regression results show that the better positioned a generator was to profit from a price increase, the more that generator would mark up its bid over cost. He similarly demonstrates that bids were marked up more when market conditions were tight. Together these results suggest that the generators' mark-ups were the result of market power exercised.

Q. Did the pattern of high mark-ups and spiked bids noted by Drs. Berry and Hanser change over time in any significant way?

A. Yes, both of these witnesses noted the decline in spiking and mark-ups as price caps were reduced. As the lower caps limited bidding opportunism, bids fell closer to marginal production costs. This situation lasted until the hard $250 cap was replaced with the "soft" $150 cap in December 2000. Mr. Hanser's graphs show that in December of 2000 and January of 2001, generator bids and mark-ups reached uncharted heights. The model competitor in the earlier period, Duke's RT bids in January 2001 increased to over $3,000/MWh while its costs were roughly $150. Similarly, Williams' bids rose as high as $1,600/MWh on costs of approximately $500/MWh. During the Christmas Holiday week Dynegy's bids topped $1,500/MWh on costs of around $300/MWh. These margins ranging from $1,000 to $3,000/MWh are simply without justification on any economic basis. Powerex placed a few high bids into the "soft cap" market (ranging from $750 to $1,100/MWh in December 2000 and January 2001, and then exited the RT market for good in favor of selling to CERS.

Withholding from PX and DA Markets through the Declaration of False Outages

Q. You have stated that one way in which sellers could withhold supply from RT (and DA) markets is through the false declaration of outages. Is there evidence that sellers falsely declared their generating units out of service during the Crisis Period in order to withhold capacity from the market?

A. Yes. Mr. Hanser's testimony presents evidence showing that all five of the Big Five generators made declarations of outages to the ISO where their own plant records show that the plant was available during the Crisis Period.

Q. How does Mr. Hanser identify evidence of false outage reporting?

A. Mr. Hanser compares internal records kept by plant personnel to generators' representations to the ISO. Through this comparison, he was able to identify a number of instances in which representations to the ISO that a unit was out of service due to an equipment failure were false, and the plant owner simply chose not to operate the unit.

Mr. Hanser also identified certain specific instances when plants were declared out of service for invalid reasons. He identified an instance where an outage was extended by AES/Williams for financial reasons, an incident where Reliant took a plant out of service due to the high cost of NOx permits, and an incident where Dynegy took a plant out of service for more than two weeks due to staff vacations.

Q. Is there evidence that generators declare false outages during emergency periods?

A. Yes. Mr. Hanser found evidence that suspicious outages were reported by Dynegy, Mirant and Reliant during system emergencies, and that Duke, Dynegy, Mirant and Reliant placed their units on reserve shut-down (shutdown for economic reasons) during emergency hours. Mr. Hanser further identifies approximately twenty instances in which the Big Five placed units on reserve shutdown (*i.e.,* shut the plants down for asserted economic reasons) during ISO declared system emergencies. As CA parties witness Mr. Tarplee – the manager of system operations for Southern California Edison Company – testifies, this conduct violates the WSCC reliability standard applicable to generators during the Crisis Period.

C. PATTERNS OF WITHHOLDING BEHAVIORS DURING THE CERS PERIOD

Q. Please describe the main market structure changes during the CERS period.

A. The CERS period began on January 17, 2001 when the PX market effectively stopped operating the DA spot market. At this time, the utilities were no longer required to sell their generation into the PX, instead using it to serve their customers. The net short position of the California IOUs was purchased by CERS bilaterally. Although the ISO continued to determine when conditions were such that OOM purchases were necessary, and the required amount of such purchases, the ISO's credit condition was such that CERS had to guarantee payment for these purchases. CERS submitted its schedule to the California ISO, which continued to provide AS and operate the RT and OOM markets for balancing energy.

The Commission also began modifying its soft cap approach during this period and later adopted further mitigation policies. The modifications

to the RT price caps were not applied to OOM purchases by the ISO. Thus, the motivation of suppliers was to shift supply away from the non-bilateral markets, further reduce RT supply and induced large uncapped OOM purchases.

Q. What were the implications of this new market structure for the withholding strategies discussed by the California Parties?

A. There were a number of important implications. First, the elimination of the PX meant that there was no longer a distinction between the bilateral markets and the PX. The California IOUs indirect ability to access the bilateral markets (now via CERS purchases on their behalf) eliminated withdrawal from the PX market itself as a withholding strategy.

This meant that sellers' attempts to exercise market power prior to RT could come only in the form of high-priced bilateral offers to CERS or failing to offer CERS power at all. There was no formal, single-price auction for CERS purchases. Thus, there are no systematic records of quantities and prices offered by suppliers.

Q. In view of this, is it possible to analyze major suppliers' withholding behavior during the CERS period?

A. Not with the same precision as was possible for the pre-CERS period. However, the discovery and other data do shed some light on the actions of the Big Five CA generators and other major suppliers during this period.

Q. What evidence is there that withholding behavior by major suppliers continued during the CERS period?

A. It seems evident that the Big Five knew they were being scrutinized for withholding behavior during the CERS period, and were more careful to at least appear to offer power to CERS or to the ISO. At the same time, there is ample evidence that physical and economic withholding by the Big Five and by other major suppliers continued to occur.

The testimony of Mr. Philip Hanser concludes that physical withholding in the form of reserve shutdowns and false outage declarations continued through the CERS period. As was seen throughout Summer 2000, Duke again stands out as a supplier with a dramatically lower incidence of reserve shutdown and suspicious outages.

Economic withholding – *i.e.*, simply offering power to CERS at extremely high prices – is amply documented in the California Parties' discovery of supplier communications during this period. Here there appears to be no distinction between the actions of the Big Five and importing sellers (nor would one be expected).

Mirant appears to have purchased large quantities of power from Powerex, marked it up by $50, and sold it to CERS. An email dated April 9, 2001 reads:

> *"IMPERATIVE!! WE ARE ABOUT TO HIT OUR CREDIT LIMIT WITH POWERX.*
>
> *This is a big deal because we have been buying 1200 MW's per hour from them and selling to CERS at a $50 spread. This means that if we can't get more credit with them, we will not only be missing out on $60,000 per hour but some other marketer will get the business and try to compete with us for it going forward. I don't know who has to be contacted but this obviously needs to be addressed ASAP. Talking with the guys at Powerx I think that we will hit our credit limit this morning if we continue to deals at the same size we have been doing them." (Exh. No. CA-320)*

Mirant also appears to have purchased power from others in order to mark it up and sell it to CERS:

> *We did a great number of trades during the evening, buying energy from mainly AEMC and EPMI and flipping it to CERS. Came away with a good deal of dinero for two consecutive nights.*
> *(Exh. No. CA-140)*
>
> *"Continued to sell power to CERS at Malin for most of the Off-peak from AEMC and EPMI and made some good margin on the trades."*
> *(Exh. No. CA-318)*

Such markups are also frequent for power that Mirant "flips at malin" before selling to CERS (*e.g.*, Exh. Nos. CA-317, CA-140, and CA-138).

Mirant recognized that by selling large amounts of power to CERS, it would decrease its profits on its sales to CERS:

> *Let;s [sic] try and not sell our power too early. CERS is trying to get cheap power by buying ahead of time... CERS is the last people we want to show power to. ...we have been selling a lot of SP to [PowerEx] so let's keep it going (Exh. No. CA-137)*

Q. Besides offering high-priced bids to CERS, were there other withholding strategies used in the new market structure?

A. Yes, another form of market power exercise during this period was sellers' attempts to impose on the ISO a minimum purchase duration for OOM power. A requirement that a multi-hour or multi-day block of power be purchased is simply another way of raising price for a buyer who does not want as large a total quantity at the offer price but would be willing (absent sellers' market power) to take a lesser amount.

Q. After the soft cap was implemented, sellers charging prices above the soft cap were required to document their actual costs. For the portion of Big Five sales that required sellers to document actual costs, did the California Parties' discover documents raising concerns that sellers may have manufactured inflated and incorrect cost justifications?

A. Yes. The testimony of California Parties witness Michael Harris discusses possible manipulation of the gas price indices which could be relied upon for cost justification, or for later use in calculating refunds based on maximum allowed prices. In addition, the analyses of Dr. Berry and Dr. Reynolds both find that some generation sellers offered to sell power at prices that reflected gas costs below those of contemporaneous published gas price indices. This indicates that the sellers themselves did not consider these indices accurate measures of the opportunity cost of their gas at the time they were consuming it.

Concern over cost justification is also evident in the communications of traders. A December 9, 2000 email from Mirant's RT trader says to other Mirant traders: "We need to sell something, anything to help justify our energy price. I showed Williams $800 [per MWh] with room to play. Stacy [evidently Williams' trader] did not even want to come outside." (Exh. No. CA-136) In the same document, this trader discusses the relationship between generation bids and cost:

> *We are selling services and the energy behind them. We are selling spin and unspin at 250 and the energy at $700, which is the gas price times the average heat rate of 10, we should be charging $600. Todd, I'll let you make the call whether or not you want to lower it.*

Note that this quote indicates that a 15% "marginal profit factor" was added on top of a bid basis that were already, by this seller's own calculation, $100/MWh above a marginal costs estimate based on the gas spot prices. Finally, information from the ISO indicates that the ISO did not receive adequate documentation of sellers costs for bids accepted above the soft cap. (Exh. Nos. CA-297, CA-298, and CA-299)

D. EXPORT-IMPORT PATTERNS AS FURTHER EVIDENCE OF MARKET WITHHOLDING

Q. Is there evidence that during the crisis period, sellers used other ways to increase withdrawals from the DA markets?

A. Yes. Exports from the CA DA markets increased dramatically during the crisis period. As I have explained, exporting from DA markets is another way to withhold energy from these markets. Even if energy exported in DA markets is then re-imported in RT (as in Ricochet transactions), this DA withdrawal can have economically harmful effects on both DA and RT markets.

Q. Did export and import patterns in the California markets change during the period from May 2000 to June 2001?

A. Yes. It has long been acknowledged that the California electric market is dependent on imports for its power supply. Traditionally, the California market imports power during the summer and exports power to the Pacific Northwest during the winter. Analysis of the export/import behaviors in the California market suggest a dramatic shift in the patterns of import and export schedules during the Western power crisis. As discussed below, these changes are consistent with a growing incidence of export-import games beginning in Summer 2000 and continuing through the implementation of the West-wide price cap on June 20, 2001.

Q. What analyses of Export/Import patterns did you conduct?

Figure C-1 in Appendix C of Exh. No. CA-2 depicts import and export for the ISO system, presenting pre-scheduled net imports from March 1999 through December 2002 to provide a view of changes in overall net imports across time. Figure C-2a presents an analysis of the patterns underlying the shift in imports and exports that occurred during the period from January 1, 2000 through April 30, 2000. Figures C-2b to C-2d present a detailed look at imports and exports from May 1, 2000 through June 19, 2001.

Q. How did the export/import patterns change during the Period from May 2000 through June 2001?

A. Figure C-1 shows the pre-scheduled (*i.e.,* DA and HA) net imports into the ISO system from March 1999 through December 2002. This figure shows that there was a significant, approximately 3000 MW decline in

DA and HA ("DA/HA") net imports during a 17 month period from May 2000 through September 2001. For the January 2000 through June 2001 period, Figure C-1 also shows total net imports which also include both RT and OOM markets. The comparison with net imports based solely on DA/HA data shows that the reduction in net imports was significantly less pronounced when RT and OOM transactions are included. The substantial magnitude of this difference over the May 2000 through June 2001 shows that the decrease in DA/HA net imports was offset by large RT and OOM imports in the range of 500 MW to 2500 MW average per month.

Q. What patterns appear when analyzing imports and exports during the period from January 1, 2000 through June 19, 2001?

A. Figures C-2a to C-2d provide a more detailed picture of imports and exports on a DA, HA, RT, and OOM basis for each of the four time periods—Spring 2000 (Figure C-2a), Summer 2000 (Figure C-2b), Fall/Winter 2000 (Figure C-2c), and Spring 2001 (Figure C-2d). (Imports into the ISO System are shown as positive values and exports are shown as negative values. The incremental imports and exports in the DA, HA, RT, and OOM markets are stacked on top of each other, such that the total positive values reflect total imports and the total negative values represent total exports.)

Figure C-2b is particularly instructive in understanding the nature of the decline in DA/HA net imports. The Figure shows that DA/HA imports into the ISO system generally fell into the range of approximately 6,000 to 7,000 MW through the May-October time period. The reason why DA/HA *net* imports declined, is a sharp rise in DA/HA exports—increasing from approximately 2,000 MW in early May to 4000 MW in early June and to approximately 5,500 MW for the late July and August period. Figure C-2b also shows that the approximately 2,000 MW increase in DA/HA exports roughly corresponds to an increase in RT and OOM imports of similar magnitude.

A similar picture is documented in Figure C-2c for the October 2000 through January 2001 period. The figure shows that average DA/HA exports increased from approximately 2,000 MW in early November to approximately 4,000 MW for mid-November to mid-December. The figure also shows that during the same time period RT and OOM imports increased from roughly 1,000 MW in early November to approximately 3,000 MW for mid-November to mid-December. I will

discuss this close correlation in DA/HA exports with RT and OOM imports in greater detail below.

Figure C-2c also shows that the ISO import mix shifted from more than 2,000 MW of RT and much smaller OOM imports in mid-November to mostly OOM imports in early-December. These OOM imports were, as explained earlier, subject to less stringent price controls. By early December 2000, the RT imports into the ISO were replaced almost entirely by OOM imports, and there was also a decreasing reliance on DA and HA imports.

This simultaneous increase in DA/HA exports and RT and OOM imports during the November and December 2000, and the corresponding shift from mostly RT imports to mostly OOM imports is particularly pronounced for exports and imports between the ISO's northern zone (NP15) and the Northwest. This close correlation and subsequent trend to OOM is documented in Figure C-3. Of course, this is the period when credit concerns and high gas prices impacted the market, leading to CERS' assumption of IOU purchasing in January 2001. All this plays a role in the shift to larger levels of OOM.

Figure C-2d shows that DA/HA exports from the ISO for January through June 2001 (when CERS/CDWR was purchasing power to meet a large portion of California's power requirements) were generally between 3,000 MW and 4,000 MW—which was significantly higher than the 1,000 MW to 2,000 MW of DA/HA exports during the spring of 2000. This pattern is also consistent with the increased use of Ricochet games. Figure C-2d also shows that OOM purchases accounted for roughly 2,000 to 4,000 MW of imports (mostly purchased by CERS on behalf of the ISO) during the February through May 2001 period. This enormous magnitude of OOM imports compared to DA/HA imports in the range of only 4,000 MW to 6,000 MW which, together with the high levels of DA/HA exports, resulted in the historically low DA/HA net imports shown in Figure C-1.

As I will discuss further in Part B of my testimony, these shifts in import and export patterns are consistent with the growing use of export/import games by generators and traders to evade the ISO price caps and FERC refund liabilities.

Q. In our discussion of export-import patterns in Figure C-2d, you noted that during the Spring of 2001, between 2,000 MW to 4,000 MW of imports were accounted for by OOM energy that was mostly purchased by CERS on behalf of the ISO. Have you analyzed how much of the ISO's OOM import requirements were accounted for by CERS purchases?

A. Yes. The pattern and magnitude of OOM imports purchased by CERS on behalf of the ISO is illustrated in Figure C-4. It shows that during the January through June 2001 period essentially all of the ISO's OOM import requirements were purchased by CERS. Purchases by the ISO accounted for a small portion of OOM imports only in January and early February.

Figure C-4 also shows a very striking transition of RT imports increasing from less than 1,000 MW to approximately 2,000 MW in November. Significant OOM imports by the ISO started in mid November at an average level of approximately 1,000 MW. These OOM imports by the ISO reached 2,000 to 3,000 MW in December of 2000, essentially entirely replacing the ISO's RT energy imports. In January-February 2001, the ISO's OOM imports declined, while OOM imports by CERS (on behalf of the ISO) increased sharply, essentially replacing the ISO's own OOM imports by mid February. By mid February, total OOM imports had increased to a level of 4,000 MW. OOM imports by CERS remained at an average level of approximately 4000 MW (but at times exceeding 5000 MW) through the end of May.

However, note that the high level of OOM imports by CERS during the February through May 2001 period is associated with much lower DA imports. During November 2000, DA imports into the ISO service area (representing PX and bilateral sales) were at an average level of approximately 7,000 MW. During the January through June 2001 period, DA imports averaged only about 5,000 MW. This increase of OOM imports as a replacement of DA imports is further evidence of suppliers' withholding from the DA market. Note that DA imports by CERS also account for only a small portion (*i.e.*, approximately between 200 MW to 1000 MW) of total CERS imports.

Q. You noted that this combination of higher levels of OOM imports but lower DA imports further documents suppliers' withholding from the DA market. Is there any evidence that suppliers intentionally withheld their sales from the DA market?

A. Yes, there is. In a March 18, 2001 email, a Mirant trader quite clearly recommends that the company withhold from the DA market:

> *Let;s [sic] try and not sell our power too early. CERS is trying to get cheap power by buying ahead of time, if you don't see a good bid then hold off. ... CERS is probably the last peopple [sic] we want to show power to. (Exh. No. CA-137)*

As I will discuss further below, Mirant was a major importer of power during March and April 2001. (See Figure C-9)

E. EXPORT-IMPORT PATTERNS AMONG THE BIG FIVE CALIFORNIA GENERATORS

Q. You just summarized how the pattern of overall export and imports changed over the course of the January 2000 through June 2001 discovery period, pointing out that the Summer of 2000 fundamentally changed the export-import pattern that existed prior to the power crisis. Have you analyzed the extent to which the Big Five generators have contributed to the change in this overall pattern?

A. Yes, I have. Figures C-5 through C-10 (in Appendix C) show the exports and imports for the Big Five generators for the entire discovery period, both as a group (Figure C-5) and individually (Figures C-6 through C-10). As was the case for the earlier figures in Appendix C, negative values denote exports out of the ISO service area while positive values denote imports into the ISO area. The stacked portions of exports and imports reflect DA schedules and incremental HA schedules, RT trades, and OOM purchases.

Q. What does the export-import pattern show for the Big Five generators as a group?

A. Figure C-5 shows that the Big Five's export-import pattern changed quite significantly over the 18 month discovery period.

- During the Spring of 2000, the Big Five suppliers' average imports ranged between 100 MW and 500 MW, strictly on a DA basis. There were no exports for which these suppliers acted as

their own SC and there was no RT activity, neither in the export nor import market. (Note, however, that these figures attribute imports and exports only to the Scheduling Coordinator which schedules the export or import with the ISO. As a result, if a supplier uses another party as the Scheduling Coordinator for an export or import, that trade would no longer be attributed to the supplier.)

- In May 2000, this picture of relatively small DA imports changed dramatically. DA imports virtually disappeared while DA exports jumped to approximately 400 MW, increasing steadily to exceed 1000 MW by the end of July. At that point DA exports (at least those scheduled out by the Big Five themselves) dropped back to 300 MW to 400 MW. However, as shown in Figure C-2b (discussed earlier), there was no such drop in overall ISO-wide exports. This suggests that the drop in Big Five's own exports did not correspond to a drop in Big Five power that was exported—but rather that the power was exported by other SCs. It is also noteworthy that, despite large RT imports during the Summer period, there was no RT activity (not even HA activity) by the Big Five suppliers.

- The Fall of 2000 shows very low export-import activities solely in the DA markets until early December 2000. At that point, which coincides with the introduction of the soft price cap on December 8, the Big Five suddenly showed an approximately 500 MW spike in OOM imports that lasted through mid-January of 2001.

- These OOM imports disappeared during the second half of January 2001 (the early part of the CERS period), but reappeared in early February, increasing steadily to exceed a daily average of 1000 MW (per hour) in early April. At that point, these OOM imports dropped again and decreased steadily through the remainder of the discovery period in June 2001. During the entire CERS period DA exports and DA imports ranged from 200 MW to 500 MW.

Q. Is the overall export-import pattern for the Big Five consistent with the export-import pattern for each of the individual suppliers?

No. As shown in Figures C-5 through C-10, the export-import pattern differs substantially among the Big Five suppliers. The overall pattern discussed for the Big Five as a group is generally driven by only two or three of the five suppliers:

- During the Spring 2000, Reliant showed no export or import activity, while the other four generators imported moderate amounts of power on a DA basis. These imports appeared consistent with the overall net import pattern that existed in California.

- The sharp increase in DA exports was primarily driven by Reliant and Williams—and to a lesser extent by Duke and Mirant (Southern). Dynegy had no export activity scheduled under its own name until late 2000. The sharp drop of DA export in the beginning of August was almost entirely associated with Reliant's and William's trading activity.

- The Fall of 2000 showed relatively little activity, with only Duke and Dynegy importing moderate amounts of DA energy. The sharp spike in OOM imports (reaching 500 MW to 1000 MW) in early December was entirely driven by William's trading activity.

- The large amounts of the Big Five's OOM imports during the CERS period was entirely due to William's and Southern's trading activity—though Mirant's OOM imports were mostly during mid-March through April 2001. Reliant acted as the SC for 200 MW to 300 MW of DA imports from late January through mid-March of 2001.

Q. You pointed out earlier that on an ISO-wide basis, the increases in DA exports coincided with a parallel increase in RT exports. You also just pointed out that the Big Five suppliers, mostly through Reliant's and Williams' own trading activities, contributed significantly to that sharp ISO-wide increase in DA exports. Is there any evidence that the Big Five suppliers might have re-imported their own DA exports?

A. Yes. Evidence obtained in discovery suggests that Reliant may have systematically re-imported in RT the very same power the company had scheduled as a DA export—although these RT imports were

"camouflaged" through parking/lending agreements and by using other utilities' names to bid that power into the ISO's RT market. (Exh. No. CA-56) However, because of Reliant's attempts at hiding the origin of its RT imports in cooperation with others, these "multi-party" Ricochet transactions are not "visible" in the export-import activities of single entities. Moreover, they are extremely difficult to find and trace. I discuss this evidence of potential MW Laundering by Reliant under my analysis of "Ricochet" transactions in Part B of my testimony.

F. GENERATION PATTERNS

Q. You have stated that although most major sellers made extensive use of withholding and manipulation strategies throughout the Crisis Period, the use of these strategies was not uniform across time or across sellers. Could you illustrate this point?

A. Yes. The generation pattern of the Big Five during this period is visually summarized in the Figures of Appendix B. These charts show how the power produced by generators owned by each of the Big Five was allocated among the markets available to them. On these charts, the "bilateral" sales category includes long-term sales, exports out of the California ISO area, direct sales to retail customers (other than those served by the California IOUs) and other forms of sales the California IOUs did not have access to. The remaining categories on the chart show the amount of generation supplied to the PX energy markets, the AS markets, and the RT and OOM markets. The charts also show the amount of generation that was supplied as uninstructed energy and schedule changes ordered by the ISO for RMR units.

The most striking element in these charts is the shift of four of the Big Five (excluding Duke) towards much larger bilateral sales starting at the beginning of Summer 2000 (See Figures B-1b to B-6b). Nearly all Williams capacity was sold outside of the PX, as was much of the others. The second interesting feature of these charts is that they summarize the visual signature of the RT withholding strategies described above. During peak generation periods, the additional energy supplied tends to be in the form of AS service bids, RT and OOM energy supplied, and finally uninstructed generation – the latter often the result of the uninstructed generation strategies described in Part B of my testimony. This pattern is less true of Williams, as nearly all its generation was sold bilaterally. More strikingly, Duke's visual signature shows much more stable generation levels and far less of the

shift of power out of the PX energy markets during the same high price periods.

The sales practices of all of the Big Five again shifted dramatically in the Fall/Winter period. Figures B-2c to B-6c shows this visually using the same format as the previous exhibit. These exhibits show that the total sales of all of the Big Five became extremely volatile, with much greater proportions of output going to AS, OOM, and uninstructed energy. Dynegy in particular stopped selling nearly any bilateral or PX energy during December 2000. Also, Duke's pattern of sales in November and December no longer differs so markedly from those of the other Big Five.

The sales practices of the Big Five during the CERS period (Figures B-2d to B-6d) are consistent with the changes in the structure of the CA markets over that period. With the demise of the PX, the Big Five's bilateral sales increased although these "bilateral" sales now included sales to CERS (which stepped into purchase the power requirements of the IOUs). Almost all of Duke's sales during the CERS period came from bilateral sales and uninstructed generation. After the first week of March, Williams, Mirant, Reliant, which had sold capacity in A/S and RT markets, stopped. Only Dynegy continued offering A/S and RT energy in meaningful units after the first week of March. Total sales by the Big Five were more volatile in the first half of this period than in the second half. As Figure B-7 and B-8 show, the generation mix of the IOUs and another CA generator, Calpine, tend to be much less volatile, both in terms of the amount of generation offered for sale and the markets in which it was offered.

These visual signatures tie to changes in supply conditions and costs among the generators as well as the new rules and their bidding and withholding strategies. Broadly speaking, all of the major changes occurring in the market would induce suppliers to shift supply away from the PX markets towards the RT and OOM markets. Within this broad shift, suppliers had the following options once the soft cap became operative on December 8, 2000: (1) submit bids below the soft cap into the RT market without cost justification; (2) submit bids above the soft cap and provide cost justification; (3) hold out for OOM purchases, which sellers argued did not require cost justification; or (4) bid into the AS markets and include a high energy bid. The Big Five used all of these options during this period.

Q. You noted that with the demise of the PX, CERS stepped in to procure power on behalf of the IOUs. Have you illustrated this transition from the PX market to CERS purchases?

A. Yes. This transition from the PX market to CERS purchases on behalf of the IOUs is illustrated in Figure B-9. This figure is similar to Figures B-1a through B-1d in that it shows how the power produced by the Big Five generators is allocated among the markets available to them. However, this figure also breaks out separately the Big Five's ISO-internal DA sales to CERS and other bilateral DA sales. As shown in Figure B-9, after the demise of the PX in mid to late-January of 2001, sales to CERS essentially replaced the PX market within weeks. By late February 2001, the Big Five's DA sales to CERS accounted for roughly the same proportion as the generators' sales into the PX during the Summer of 2000. Note, however, the large other bilateral sales compared to the generators' increasingly smaller sales into the various ISO markets.

By early March 2001, sales into the various ISO markets only accounted for several hundred MW, down from 4,000 MW in December of 2000. The shift from PX and ISO markets to non-CERS bilateral sales—at a level of approximately 5,000 MW per hour—also indicates that much of the Big Five's generation was exported on a DA basis. As Figure C-4 shows and as I further note in my discussion of export-import patterns and Ricochet trades, a significant portion of DA exports was re-imported as OOM sales to CERS.

VI. PATTERNS OF USE OF THE MANIPULATIVE TRADING STRATEGIES

Q. You have explained that there is a close relationship between withholding strategies and manipulative trading strategies, as major sellers' ability to exercise market power by withholding was enhanced by manipulative trading strategies, and manipulative trading strategies were made profitable by withholding. Is there evidence that manipulative trading strategies were widely used during the Crisis Period?

A. Yes. There is evidence that a group of ten to fifteen importing traders used variations of the five Enron strategies listed in Table 1 (Ricochet, Fat Boy, Death Star, Cut Schedules, and Get Shorty) on tens of thousands of occasions throughout the crisis period. The main perpetrators of each of these strategies tends to be drawn from the same list. The periods during which these sellers use the strategies, however, varies widely. Some strategies are used consistently through the full period, while many others are used by some sellers only during some sub-periods. The Big CA generators appear to be more selective than traders in their use of manipulative trading strategies, both by strategy and by time period.

Evidence suggests that the patterns of use of manipulative trading strategies changed at the start of the CERS period. This is exactly what I would expect to see. Just as changes in the structure of CA short-term energy markets at the start of the CERS period fundamentally altered the ways in which sellers could withhold energy from CA markets, changes in market structure also altered the ways in which sellers could use manipulative trading strategies.

Q. To what degree did major sellers use the Ricochet trading strategy?

A. Ricochet export-import games appear to be the most widely used manipulative trading strategy of the five examined. My screening of the trades by individual sellers, which overcounts some trades that are possibly not Ricochets but is unable to quantify any multi-party Ricochet trades, found approximately 15,000 hourly instances of potential single entity Ricochet transactions involving more than 2 million MWh of generation. By comparison, this is roughly the same number of MWh as passed my screen for unusually large volumes of

uninstructed generation (which, as noted above, is a sign of RT withholding).

My screen can only identify single entity Ricochet transactions because Ricochet transactions that involve multiple parties are very difficult to detect in the available data. For example, consider a situation where an in-state generator exported power in the DA market, sold it to Powerex outside of the California ISO, and then Powerex sold the power back to the California ISO in the RT market. This would have been an effective way to withdraw power from the PX DA market and sell it back in RT, but it would be very hard to detect this behavior in the data that was available to me. As I have discussed, there is evidence in the overall pattern of exports and imports during the crisis period that a large volume of energy that was exported DA was re-imported in RT. Therefore, it is likely that my screen that yielded the 2 million MWh figure by capturing transactions only when the same scheduling coordinator imported and exported the power identified only a subset of all Ricochet transactions.

Q. How did use of the Ricochet strategy vary by seller and by time period?

A. Figure D-7 shows the occurrences of potential Ricochet transactions by major sellers by day over the Discovery Period. It indicates that use of the Ricochet strategy was rare prior to the Summer of 2000, and that the Ricochet strategy was used most frequently and by the largest number of sellers in the Summer and Fall of 2000. The number of sellers using the Ricochet strategy was smaller during the CERS period, but the sellers that used the strategy used it on many days.

My analysis shows that the greatest volume of potential single entity Ricochet trades occurs during the Summer (over 845,000 MWh), dropping to 470,000 MWh during the Fall period. The volume of potential single entity potential Ricochet transactions during the CERS period (687,000 MWh) again suggests that the smaller number of sellers who used the strategy during this period used it intensively. During the CERS period there was no longer a PX to insert a purchase bid, so Ricochets during this period took the form of bilateral purchases within the California ISO and a later sale, usually in the form of OOM energy paid by CERS, back to the ISO in RT. This modified Ricochet had the same economic effect of reducing supply prior to RT and increasing it

in RT, ideally (from suppliers' standpoint) in the form of uncapped OOM.

My data indicate that over the entire Crisis period, Powerex was the most active user of the Ricochet strategy. As shown in Table D-1, Powerex and six additional sellers (Puget, PacifiCorp, Williams, APS, Idacorp, and Sempra Energy Trading) together account for over 90% of the total volume of potential single entity Ricochet transactions. Table D-2 shows that during the CERS period, the vast majority of potential single entity Ricochets were scheduled by Powerex, Williams, APS, Sempra Energy Trading and LADWP. Powerex alone accounted for 67% of potential Ricochet trades during the CERS period.

Q. To what degree did major sellers use the Fat Boy strategy?

A. Major importers used the Fat Boy strategy often during the Crisis Period. It was not used as frequently by in-state generators. However, as is explained in Part B of my testimony, this strategy allowed Dynegy, Mirant, and Reliant to subvert the ISO's rules for bidding and RMR unit dispatch, diverting their units from the DA market into the RT market, much like the Ricochet strategy described above.

The number of parties using this strategy is masked somewhat by the fact that parties sell into the California markets using scheduling coordinators. For example, Enron had a web of arrangements with supply entities throughout the WECC who provided power that was scheduled through the Fat Boy arrangement. Documents reveal that some of these entities were very aware of these arrangements and consciously participated in the schemes.

Q. How did use of the Fat Boy strategy vary by seller and by time period?

Figure I-5 shows the occurrences of the Fat Boy strategy by major sellers by day over the Discovery Period. It indicates that the Fat Boy strategy was used on many days by many sellers both during and prior to the Summer of 2000. Use of the Fat Boy strategy diminishes greatly during the CERS period, as would be expected when there is no longer an organized DA market to be bypassed, as when the PX was operating.

As explained in Part B of my testimony, I use a conservative test in order to identify sellers that were both persistent users of the Fat Boy strategy and that overstated their load to a significant degree. Since my

conservative screen excludes sellers who used Fat Boy on only some days during a period, it does not identify Dynegy as a persistent user of Fat Boy, even though Dynegy used Fat Boy during many days during May, 2000.

My conservative screen shows that unlike the Ricochet strategy, scheduling false load is used to some degree prior to the Summer of 2000, but that the average levels of false load are on the order of 100-150 MW (although Enron's false load was on the order of 190 MW during this period). During Summer 2000, the number of traders using the strategy increased, and the average percentage of time that individual sellers use this strategy increased. Enron uses the strategy in 90% of all hours in which it had scheduled or metered load during the Summer and Enron's average level of false load jumps from 187 MW prior to the Summer to 411 MW during the Summer – roughly a third of Enron's actual average load.

As Table I-1 shows, Enron, Mirant, Sempra, Powerex, PG&E Energy Trading, City of Anaheim and the City of Pasadena were the largest users of this strategy. In addition, note that several sellers who used this strategy during the Summer (such as Mirant and Hafslund Energy Trading) had zero actual load, yet scheduled an average of hundreds of megawatts of load each hour during this period. It is impossible to see how this pattern of conduct was anything but willful.

Q. To what degree did major sellers use the Death Star and Cut Schedules strategies?

A. My analysis shows that Death Star and Cut Schedules are used consistently throughout the Crisis Period, and in the Spring of 2000. This is what I would expect to see. Because Death Star and Cut Schedules are false congestion relief games and congestion is not limited to high-price periods, I would not expect these strategies to map closely into the high price periods, nor to go away during the CERS period. The same applies to Get Shorty, which involved submitting inflated AS offers in the DA market and then buying them back or double-selling the energy in RT.

A problem in the analysis of congestion games is that congestion games were sometimes quite complex involving several counterparties. Without documentary evidence describing such schemes, (as can be found in the Enron memos and documents as well as in documents from

market participants such as Glendale and LADWP), it is difficult to determine what strategies may have been used. Thus, my analysis may be underestimating the use of these strategies.

Q. How did use of these congestion games vary by seller and by time period?

A. Figure E-2 shows the occurrences of the Death Star and Cut Schedules strategy by major sellers by day over the Discovery Period. It shows that a number of major sellers used these congestion games on many days prior to the CERS period, and that some of these sellers continued to use congestion games during the CERS period.

My screen for potential Death Star trades (which has the potential to overstate single-scheduler Death Star transactions) found that the volume of transactions that are potential Death Star trades did not vary greatly during the Crisis Period. Table E-2 shows that there were roughly 3,200 MWh of potential Death Star transactions per month during the Summer, roughly 5,200 MWh of potential Death Star transactions per month during the Fall, and roughly 2,200 MWh of potential Death Star transactions per month during CERS period. Table E-1 shows that Enron Power Marketing, Coral Power, Sempra Energy Trading and Morgan Stanley Capital Group used potential Death Star transactions most frequently, together accounting for 82% of potential Death Star transactions.

My screen for Cut Schedules also found that the volume of Cut Schedules did not vary greatly during the Crisis Period. Table F-2 shows that there were roughly 2,500 MWh of Cut Schedules per month during the Summer, roughly 1,200 MWh of Cut Schedules per month during the Fall, and roughly 1,000 MWh of Cut Schedules per month during CERS period. The same sellers that had a significant number of potential Death Star transactions (Enron, Coral, Sempra and Morgan Stanley) also had significant amounts of Cut Schedules. In addition to these sellers, Dynegy and Powerex, among others, had a significant number of Cut Schedules. This information is summarized in Table F-1.

Q. To what degree did major sellers use the Get Shorty?

A. Get Shorty involves selling AS in the DA market and then buying back a portion of the capacity in the HA market, presumably when the seller

does not actually have AS capacity to offer. The ISO can monitor the capacity available to offer AS for in-state generators. As a result, Get Shorty is used primarily by importers. The re-purchase of some DA ancillary services capacity sold is not necessarily nefarious. Generating units used to sell AS can subsequently experience forced outages. In such cases, the re-purchasing of ancillary service capacity is entirely appropriate.

I employ a screen to identify suspicious AS buybacks. The screen is based on my observation that, for some parties, DA sales of AS in hours of buyback are substantially larger than ultimate (HA) sales of AS in hours with no buyback. Based on this observation, I identify a day as suspicious if a buyback of AS occurs and if the average daily DA amount sold is more than 10 MW greater than the average HA ancillary services sales in hours with no buyback. Days so identified are displayed in Figure G-1.

Of the five manipulation strategies that I analyzed, Get Shorty appears to have been used the least. That said, Enron, Sempra, Coral and Powerex all appear to use Get Shorty for a substantial portion of the Summer and Fall of 2000. For example, Enron buys back a portion of its DA ancillary services sales in 380 on-peak hours from May 2000 to October 1, 2000. During those hours, it re-purchased more than 60% of the capacity it sold in the DA market. In addition, its DA ancillary services sales during hours of buyback were more than 3 times its ultimate AS sales during hours with no buyback. Coral's buybacks offer an alternative pattern. Coral repurchased all of its DA ancillary services sales in each of 440 on-peak hours from October 2, 2000 through January 17, 2001 though its average DA ancillary services capacity sold during buyback hours was roughly equal to its ultimate sales in non-buyback hours.

Q. How did the use of the Get Shorty strategy vary by seller and time period?

A. At least one entity appears to have been actively using the Get Shorty strategy at all times during the Crisis period. For instance, Enron's activity appears to stop by mid-November, while Sempra's activity does not appear to start until early June. The greatest concentration of activity appears to be early June through early to mid-December. During this time period, Enron, Powerex, Coral, and Sempra are all buying back AS frequently. While the use of Get Shorty falls

substantially starting in January, 2001, Modesto Irrigation District starts to use the strategy regularly at the same time.

Q. Do you have any special concerns about Powerex's role in the market?

A. Yes. Powerex appears to be an important and complex participant in the CA markets. For example, it has produced discovery indicating that it accounted for as much as 70% of the RT market at certain points in time — a very high market share.

Due to the fact that significant new discovery was delivered by Powerex only days before my testimony was due I have been unable to fully analyze the documents produced. However, my preliminary review indicates that the documents denoted as Exh. Nos.CA-83, CA-38, CA-39, CA-44, CA-51, and CA-175 at a minimum provide useful background information and should be a part of the Commission's record in this proceeding."

PART B

HARMFUL TRADING STRATEGIES

VII. INTRODUCTION

Q. What is the purpose of this section of your testimony concerning trading strategies?

A. Scheduling coordinators used a variety of trading strategies, beyond pure economic or physical withholding of energy bids, to profit from market conditions and rules. Some of these strategies have been immortalized in the so-called Enron memos,[33] but other strategies have also been employed to manipulate the California power markets. For each of these strategies, it is important to understand how they harmed the market, which sellers pursued them, and the magnitude and frequency of their use. This section of my testimony addresses these questions.

Q. Do you believe that all trading strategies are improper?

A. No. Not every form of profit-seeking behavior is or should be prohibited. Obviously, this would defeat competition entirely. In this testimony I separate trading strategies whose primary objective is to subvert market rules and/or not contribute to economic efficiency from those primarily consistent with pro-efficient, pro-competitive behavior.

Q. What are the principal sources of harm for the strategies you analyze?

A. The specific practices that reoccur in many strategies are:

- Submitting false information to the PX or ISO that was intended to create higher prices overall than would occur absent the false information. This includes information that created payments for services not actually rendered or that contributed to reliability problems.

- Transferring sales to the RT market rather than the DA or HA markets because the RT market could be manipulated more easily, and would ultimately pay uncapped prices. Given these conditions, certain trading strategies that ultimately ended in sales to the ISO evaded price caps in both the PX and the ISO. Other strategies

[33] Exh. No. CA-78.

evaded ISO monitoring of supplier behavior. In simple terms, this is raising price through evasion of price cap and shifting to markets that are more easily manipulated. Section II of Part A of my testimony explained this phenomenon in more detail.

Q. Do the plea agreements of Enron traders Jeffrey Richter and Tim Belden support your view of the harm inherent in manipulative trading strategies?

A. Yes. Under the heading "scheme to Defraud" Mr. Richter's plea agreement (Exh. No. CA-206 at 3 to 4) states:

> *In 2000, I and other individuals at Enron agreed to devise and implement fraudulent schemes through these markets. We designed the schemes to obtain increased revenue for Enron from wholesale electricity customers and other market participants in the State of California. The schemes required us to submit false information to the ISO in the electricity and ancillary services markets described above. Among other things, we knowingly and intentionally filed energy schedules and bids that misrepresented the amount and geographic location of the load we intended to serve. We did so for the purpose of increasing the appearance of congestion on transmission lines , increasing the market price for congestion fees for transmission between zones, earning congestion payments that otherwise would not have been available, and increasing the value of our FTRs (which only generated revenue when congestion existed).*
>
> *We also submitted bids to supply ancillary services that we did not have, or did not intend to supply, in the ISO's day-ahead ancillary services market. The bid we submitted contained fabricated information regarding the source and nature of the ancillary services we proposed to supply the ISO. Once the bids were accepted, we would cancel our obligation to supply the ancillary services by purchasing them in the ISO's hour-ahead ancillary services market. Enron would then profit by capturing the difference in price between the two markets.*
>
> *As a results of these false schedules and bids, we were able to manipulate prices in certain markets, arbitrage price differences between the markets, and obtain congestion fees*

> *in excess of what we would have received with accurate schedules and bids*

Additionally, charges to which Mr. Belden pled guilty (Exh. No. CA-182 at 111) include:

> *Mr. Belden and his co-conspirators also exported and then imported amounts of electricity generated within California, in order to receive higher out-of-state prices from the ISO. Mr. Belden and others also scheduled energy that they did not have or intend to supply.*
>
> *As a result of these false schedules and bids, Mr. Belden and others were able to manipulate prices in certain markets, arbitrage price differences between the markets, obtain congestion management payments in excess of what they would have received with accurate schedules, and received prices for electricity above price caps set by the ISO and the Federal Energy Regulatory Commission.*

Q. Over what time period do you conduct your analysis?

A. The design, operation, and specific forms in which dysfunctionality and manipulation took place evolved significantly during the course of the power crisis. For organizational purposes, I organize my collection of evidence concerning potentially manipulative actions into three periods: Summer 2000 (roughly 5/1/00 through 10/1/00); Fall-Winter, which extends until the demise of the PX market (10/1/00-1/17/01); and the CERS period (1/18/01-6/19/01). I also present evidence for the Spring of 2000 (1/1/00-4/30/00) to provide a contrast and reference point for the later periods.

Q. What is the basis for the conclusions you reach about the use of trading strategies?

A. I rely upon evidence regarding the use of these strategies both from analyses of trading data and a review of e-mails and other documents discussing sellers' activities. The analyses help illustrate the patterns and pervasiveness of the use of strategies, while the documents discovered often show the degree to which sellers knew what they were doing. In other words, the documents often speak to sellers' intent, among other things. In addition, they also identify some games that cannot reasonably be identified through analysis.

Q. What conclusions have you reached with respect to the use of trading strategies?

A. Within the time allotted by the Commission for discovery, it is not possible to complete a full review of the extent to which sellers pursued these strategies. In many instances, the best evidence that sellers engaged in these strategies is the sellers' own communications, (such as the tape recordings that are routinely made of trader conversations), which could not possibly be reviewed in their entirety in the time allotted. However, we have discovered a far more extensive use of these strategies than has heretofore been documented, by many sellers other than Enron and many sellers working with Enron.

As explained in Section III of Part A, another new aspect of these trading strategies is evidence the California parties have uncovered that many sellers cooperated knowingly in the execution of these strategies. This raises the prospect that conspiracies to manipulate these markets have played a larger role in the Western crisis than was previously appreciated.

With respect to the documents obtained in discovery, many of which are emails or other documents, I have assumed that these documents are accurate. Given the available time, the volume of documents, and certain delays it was not possible to depose persons familiar with each document containing potentially relevant information. Absent such more complete information, I have attempted to interpret these documents in a reasonable and conservative manner.

VIII. RICOCHET STRATEGIES

A. INTRODUCTION

Q. What is a Ricochet Game?

A. Ricochet, or Megawatt Laundering was a strategy designed to raise prices in the DA market and possibly evade price controls by exporting and then-re-importing power from generators within the ISO system. As explained in Section II of Part A, the strategy works by scheduling the export of power purchased from ISO-internal generating resources on a DA or HA basis and then scheduling and re-importing the same amount of power back into the California ISO in RT. The re-imported power is treated as an import and thus faces less stringent price controls.

Q. Do you define a Ricochet strategy in the same way as the Commission in its request PA02-2 proceeding?

A. Yes, but more broadly. In the PA02-2 proceeding, Ricochet or Megawatt Laundering is used to describe one particular variation of this strategy. In this one variation, one entity schedules an export of power purchased from the California PX only to another entity who "parks" the power for a fee, so that the power can be scheduled for re-import and sold in the ISO in either the RT markets or as an OOM sale by the same entity that exported and parked the power in the first place. I define Ricochet more broadly, to include all transactions where power was exported from California via any market (other than RT) and was simultaneously re-imported. These circular export-import trades can involve more than one entity, but can be, and often were, executed by a single party.

It is important to understand that with rare exceptions the exports and imports involved in the various types of Ricochet transactions were physically fictitious: the "flows" created by the DA export schedule were negated by corresponding import "counter-flows" in RT such that power does not ever actually flow. Although such transactions had no effect upon how electrons moved over the power grid, they nevertheless had substantial impacts because they raised prices and undermined the ISO's ability to operate the system reliably.

Q. What are the key requirements for a Ricochet trade?

A. The first requirement to schedule a Ricochet transaction is to have a source for power within the ISO system. The second step is to schedule a DA or

HA export to a sink control area outside the ISO system (the source is the ISO system). The final step is to schedule a transaction to re-import the power from an external control area (the source, which is generally the same control area that provided the sink for the export) to the ISO system as the sink. Given these requirements, there are a large number of variations on Ricochet games. Several of the main dimensions are the following:

- **What was the source of the power exported from the ISO system?** This source can be an owned resource, a bilateral purchase contract from a resource in the ISO area, or a purchase through the PX DA market. The economic effect was generally the same, but different data must be used to pinpoint the outbound leg of the trade. Economically, using any of these sources for exports raises prices in the PX either by increasing demand in the PX market (PX purchases) or by diverting generation resources that might otherwise be bid into the PX (self-generation and bilateral sales).

- **Were the import and export legs arranged by the same Scheduling Coordinator?** This game can be played by a single entity that arranges both the import and export legs, possibly with another entity facilitating the transaction by providing a parking service to "connect" the two legs. I refer to these as "single-party" Ricochet trades. Alternatively, the import and export can involve different entities and/or scheduling coordinators, which I call a "multi-party Ricochet." As discussed later, multi-party Ricochet transactions are extremely difficult to detect.

- **Could the Scheduling Coordinator serve as its own sink?** To schedule a transaction across ISO borders, the transaction must identify the source and sink control areas. Some Scheduling Coordinators are also control area operators (such as Puget Sound Energy and Powerex), and thus can use their control area as a sink for exports from the ISO. Others, such as Williams and Sempra, are required to make contractual arrangements with control area operators outside the ISO. This "rent-a-sink-and-source" arrangement is commonly referred to as a "buy-sell" or "parking" agreement.

- **Did the power exit and re-enter at the same transmission interface?** There can be a slightly different economic interpretation between power that retraces its steps back and forth over the same

transmission interface and one for which the re-import is scheduled over a different entry point.

B. RICOCHET OR MEGAWATT-LAUNDERING: DISCRETE ECONOMIC HARM AND RELIABILITY CHALLENGES

Q. Why should the Commission be concerned about the execution of Ricochet trades?

A. Ricochet transactions have several harmful economic and reliability impacts. First, Ricochets are a means of withholding power from the DA/HA PX markets, where the IOUs must buy, and sending it back into the RT market where it is more subject to further withholding and uncapped price increases. Section II of Part A explains this. In addition, withdrawals of DA/HA supply also triggered additional ISO reserve purchases, raising the price of reserves. As explained below, high volumes of Ricochets reduced the reliability of the ISO system.

Finally, as described in the discovery below, there was often an interplay between Ricochet trading and certain congestion games that caused additional harmful economic and reliability impacts. For these Ricochet-type games, the economic and reliability harm may not be isolated to those issues raised above. For example, the first leg in a Ricochet transaction was sometimes scheduled as a DA or HA export from the ISO in the opposite direction of congestion, resulting in the collection of congestion revenues. If the second transaction in the Ricochet, the RT import into the ISO, could not be scheduled due to RT congestion, the seller would sometimes cut the DA or HA export after congestion payments were awarded but before the inter-exchange between the two control areas would be finalized. This has harmful economic impacts, because congestion charges are collected when congestion is not actually relieved.

Q. How could Ricochet transactions be used to evade price controls?

A. The ISO has subsequently analyzed the potential for Ricochet transactions as a means to avoid price caps, finding that few OOM purchases exceeded price caps at times when the $750/MWh and $500/MWh caps were in place. However, the ISO also noted that the average prices of OOM purchases were in excess of market clearing prices. Thus, while Ricochet transactions may not have been able to "evade" the imposed price caps during the Summer of 2000, these transactions contributed to triggering OOM purchases by the ISO at prices higher than RT by creating a distorted picture of ISO resource balances. The likely result of which was that the ISO purchased OOM imports at prices in excess of actual market clearing

prices (*e.g.* OOM purchases at the price cap when the export marketing clearing prices ended up below cap). Moreover, the ISO pointed out that starting in the second half of November 2000, the ISO needed to purchase significant quantities of OOM imports at prices in excess of the $250/MWh price cap in effect at the time.[34] As the ISO points out further, during the first week of December most of the ISO imports were OOM purchases at prices in excess of the $250 price cap.

As explained in Section II of Part A, OOM purchases by the ISO were not subject to any price cap. The ISO would only buy OOM when it was concerned that DA supplies were low that it might not have enough RT bid supply to meet system demand. Thus, the more DA supplies were seen as being exported at the time the ISO viewed schedules and decided about OOM, the more likely the ISO would start buying OOM.

Moreover, these exports likely created a sense of shortage within the ISO system, because the exported power was not available to balance ISO-internal loads on a DA and HA basis. Given the significant concerns about rolling blackouts and other reliability issues, the sense of shortage likely created additional leverage on the part of suppliers selling power back into the state at inflated RT prices or as OOM purchases by the ISO and, starting in January 2001, CERS.

Q. Did Ricochet also facilitate evasion of cost reporting requirements?

A. Beginning on December 8, 2000, the hard price caps were converted into soft price caps. The soft cap set forth that suppliers with bids exceeding the soft cap would be paid as bid, subject to certain reporting and monitoring requirements. Under the soft caps, Ricochet trades would disguise the original source of the power and also help to inflate its original cost basis. For example, power sold from an ISO-internal generating unit would be hard pressed to justify costs that differed from the generally known cost information for that generating unit. In contrast, for purchased power, a seller might simply state the entity from which that power was purchased and the price of the power. Thus Ricochet trades could be used to circumvent cost reporting requirements in two ways: (1) they can hide the original source of the power; and (2) a Ricochet's buy-sale transaction with intermediate parties could be used to hide the true cost basis of the power being re-imported into the ISO system.

During the CERS period, an additional incentive to engage in Ricochet trades existed. CERS was purchasing large amounts of OOM imports on

[34] See Exh. No. CA-109 at 29

behalf of the ISO, and the use of Ricochet trades easily allowed suppliers to sell power from in-state resources as OOM imports to CERS. This yielded two additional benefits for the supplier: (1) immediate payment; and (2) avoidance of potential mitigation exposure since sales to CERS were believed to be less likely subject to refunds under FERC orders.

Q. Does the forced reliance on "imports" rather than internal generation create any reliability concerns?

A. Yes. One reliability issue is that Ricochet trades allow Scheduling Coordinators and generators to evade the requirements imposed upon them under their agreements with the ISO. For example, a generating unit that is scheduled to export power could no longer be dispatched under the ISO's authority during emergency conditions. This reduced authority forced the ISO to rely more heavily on OOM imports which, unlike much ISO internal generation, could not be controlled by the ISO on a RT basis. In addition, Ricochet trades allowed sellers to evade certain safeguards and monitoring efforts that the ISO was able to undertake for internal generating resources—such as the ISO's ability to verify that offered AS capacity is actually available and that generating capacity dedicated to provide AS remains unloaded unless called-upon by the ISO.

Q. Do different variants on Ricochet strategies cause the same harms?

A. As discussed above, Ricochet transactions can vary based on: (1) the source of the power; (2) how it is parked; (3) whether the exporter and importer are the same party; and (4) whether the power entered and exited over the same interface. Each of the variants of Ricochet trades using these factors creates essentially the same economic and reliability harms described above.

Q. Could Ricochet trades be efficiency enhancing or pro-competitive?

A. Some have argued that Ricochet transactions are merely a form of efficient arbitrage, *i.e.,* sellers seeking the highest-price market for their product.[35] While this may be true in other circumstances, it ignores the fact that rules applying to sales from ISO-internal generation resources were intentionally set to limit prices and impose refund liabilities on all sellers with ISO-internal generation. While, in retrospect, even the FERC determined that price caps should have been region-wide, the California-only price caps nevertheless constituted consciously crafted and adopted rules. When these rules were in effect, it was a violation of both their letter and spirit to evade

[35] For example, J. Falk writes that Ricochets are "nothing more than an arbitrage price in the DA and RT markets and, as such, [are] efficiency enhancing." *Electricity Journal*, Aug-Sep/02, p. 21. (Exh. No. CA-339)

them knowingly, regardless of whether such evasion was akin to "arbitrage" and resulted in higher revenues to the sellers.

There are innumerable rules set by government entities that bar competitors from seeking sales in markets where they might earn higher profits by taking advantage of similar "arbitrage-like" opportunities. For example, many states charge sales tax on in-state sales but exempt sales from out-of-state firms. It is not legitimate "arbitrage" to send in-state products out of the state only to sell back to in-state buyers as imports, but rather tax evasion, pure and simple. Moreover, if excessive market power is exercised in the RT market, Ricochet transactions are far from "efficient arbitrage," but rather serve as a means of enhancing the profitability of RT withholding and transmitting the market power-induced increase in RT prices and to similarly affect the DA and HA markets, as well as the other Western wholesale markets. In its review of Ricochet strategies, the Commission Staff concluded that "[t]his 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."[36]

Nevertheless, some trades that may look on inspection like Ricochet can be consistent with legitimate market participation. It is possible, for example, that a load-serving entity outside the ISO system believed that it needed power and therefore bought power from the ISO on a DA basis (or under a longer-term contract), and then found it had hourly surpluses that it could sell back to the ISO. While this may not have helped ISO markets, it was legitimate behavior from the standpoint of the buyer. Of course, if the load-serving entity and the exporter had pre-arranged that the transaction was merely parking the power on its system, so that the RT sale back to California was pre-determined to be precisely equal in size, any argument that the transaction has a load-serving basis is absurd.

In my data tables below I am not able to distinguish between some simultaneous import/export behavior that is consistent with true load-serving needs. However, given the magnitude and pattern of simultaneous import-export volumes, I believe it is impossible that the California exports were intended to serve significant non-California load.

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[36] 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, Staff of the Federal Energy Regulatory Commission, August 2002, p. 99.

C. EVIDENCE REGARDING WIDESPREAD USE OF RICOCHET-TYPE TRADING STRATEGIES

Q. Are export/import patterns discussed earlier consistent with the widespread use of Ricochet transactions?

A. Yes. As discussed in Part A, Section VI (based on Figures C-1 through C-3), overall export-import patterns during the Full Period generally were consistent with the pervasive presence of export-import gaming strategies. A more detailed review of newly discovered trading information indicates that Ricochet trades may have been used extensively during the Summer 2000 and, particularly pronounced, starting in November 2000, just before the Commission imposed soft price caps. Figures D-1 through D-6 illustrate the close correlation between exports from the ISO on a DA and HA basis and imports on a RT or OOM basis, especially to/from the Pacific Northwest. These figures chart average DA and HA ("DA/HA") exports and RT and OOM ("RT+OOM") imports during the peak hours of each day in the represented time period. The exports shown on these charts are reduced by a single constant baseline amount indicated on each chart. This is done to allow the visual alignment of the *changes* in daily peak hour imports and exports each day.

Q. What conclusions do you draw from Figures D-1 through D-6?

A. In a Ricochet transaction, each MWh of export scheduled on a DA or HA basis would, after "parking" at a location outside of the ISO system, be re-imported on a RT basis. Thus, in the presence of Ricochet games, one would expect to see a strong relationship between changes in the amount of scheduled DA/HA exports and the amount of RT+OOM imports. Figures D-1 through D-6 in fact show such a relationship:

- Figure D-1 documents a good correlation of California-wide DA/HA exports and RT+OOM imports from mid-July through the end of August 2000. Note that the pattern similarities are much weaker until July begins. It is probably not a coincidence since the ISO lowered its RT price cap (thus the effective DA price cap) to $500 on July 1. The chart shows that both DA/HA exports and RT+OOM imports increased by 1,000 MW to 2,000 MW during the second half of July. Similarly, both DA/HA exports and RT+OOM imports simultaneously dropped by approximately 2,000 MW in late August.

- Figure D-2 show a particularly strong relationship of California-wide changes in exports and imports for the Fall and Winter of 2000. Starting at the end of October 2000, both DA/HA exports and

RT+OOM imports increased in lockstep by approximately 2,000 MW and maintained a close correlation of changes through early January 2001.

- Figure D-3 shows that the general trend of DA/HA exports during the Spring of 2001 is well-matched by a corresponding trend in RT+OOM imports. Note that, unlike the other graphs, this chart does not have a baseline level of HA exports subtracted. The variance between the total exports and imports shown here clearly suggests that not all of these DA/HA exports and RT+OOM imports likely are associated with Ricochet transactions.

- Figures D-4 through D-6 show that this close relationship between DA/HA exports and RT+OOM imports is also clearly visible on a regional basis. Figure D-5 shows that, starting in late October 2000, changes in DA/HA exports from NP15 to the Northwest increased by approximately 1,500 MW in very close conformance with changes in RT+OOM imports. Figure D-4 shows a similar, though not quite as strong correlation for mid-July into the Fall. And, finally, Figure D-6 shows that in August and September 2000, changes in DA/HA exports from SP15 into the Southwest are highly correlated with changes in RT+OOM imports from the Southwest. Both DA/HA exports and RT+OOM imports abruptly fall by approximately 1,000 MW at the end of August, followed by a parallel 750 MW spike for two weeks in September.

  This evidence of parallel movements in DA/HA exports and RT+OOM imports on both an ISO-wide and regional basis strongly supports the pervasive use of Ricochet games strategies during the full period.

D. EVIDENCE REGARDING SPECIFIC SELLERS – RICOCHET

Q. What analyses have you conducted to identify the use of Ricochet transactions by individual Scheduling Coordinators?

A. The volume of likely Ricochet trading strategies by single parties can be calculated by comparing individual DA and HA exports of individual Scheduling Coordinators with their RT+OOM imports on an hour-by-hour basis. The data necessary to undertake this comparison—Scheduling Coordinators' DA, HA and RT hourly schedules and hourly OOM imports and exports—were provided by the ISO. The data provided by the ISO identified Scheduling Coordinators' hourly DA, HA and RT imports and

exports by "tie point" and by "interchange ID." Hourly OOM imports and exports are identified by Scheduling Coordinator, tie point and interchange ID.

Q. What steps did you take to conduct this analysis?

A. Because many entities (including other Scheduling Coordinators) schedule exports through the PX acting as a Scheduling Coordinator, I disaggregated the PX schedules when calculating the export-import volumes that could be part of Ricochet trading strategies.[37] Relying on the data provided by the ISO, we were able to identify imports and exports by tie point, in order to identify which potential Ricochet transactions may also relieve congestion at those tie points.

The data provided by the ISO shows that, starting in December 2000, a large volume of OOM imports were scheduled into the California ISO by CDWR and, starting in January 2001, by CERS. Because CDWR and CERS bought those imports in place of the ISO, I reallocate these CDWR/CERS imports volumes to the entities selling that power to CDWR/CERS. I was able to use interchange ID codes for these imports to determine the entities from which CDWR and CERS were purchasing this imported power and treated these sales as if they were scheduled by the party that sold power to CDWR or CERS. I also utilized purchase data obtained from CERS to verify the accuracy of the performed disaggregation based on the ISO's interchange ID codes. Finally, I used information on "sleeved" transactions in which the sleeving party earned no profit to allocate the sleeved imports to the ultimate seller.[38]

All of this processing allows for an hour-by-hour comparison of each Scheduling Coordinators' true overall DA and HA exports with their RT and OOM imports. Using this data, I determined the extent to which entity's DA/HA exports overlap with RT+OOM imports in each hour. These simultaneous exports and re-imports of power are a clear indicator of potential Ricochet transactions.

This analysis is very limited in its ability to identify Ricochet transactions because it is able to identify Ricochet trades only where the import and export legs were scheduled by the same Scheduling Coordinator (*i.e.*, "one-

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[37] By using interchange ID codes, it is possible to determine which entities scheduled imports and exports through the PX, so that PX volumes can be allocated to these entities. Also note that the description of Ricochet trading in the Enron memos indicates that Enron bought energy from the PX in the "Day Of" market and scheduled it for export. (Exh. No. CA-78)

[38] See Berry testimony, Exh. No. CA-40 in Docket EL00-95, pages 8 and 15.

party Ricochets"). If, for example, two sellers agree that one will export power and the other will re-import the same power in advance, this transaction will not show up in my data tables even though it has the identical economic and reliability impacts as a one-party Ricochet. However, as discussed later, I have also found evidence of parties engaging in multi-party Ricochet trades through my review of discovery documents. Other than noting the magnitude of the total simultaneous import-export patterns in Figures D-1 through D-6, I am unable to quantify multi-party Ricochet activity.

Q. Please describe the results of your analysis.

A. Table D-1 presents the results of my analysis of potential one-party Ricochets. The table shows that, from May 1, 2000 through June 19, 2001, a total of about 2 million MWh of DA/HA exports were matched by such RT+OOM imports. This volume of potential single Scheduling Coordinator Ricochet transactions is equal to approximately 10% of total RT and OOM imports over this same period. Of the Scheduling Coordinators with such matching exports and imports, Powerex accounted for 40% of the total (806,000 MW during 4,024 hours). These transactions thus represent a material portion of Powerex's reported revenues of approximately $1.5 billion from sales to the ISO, the PX, and CERS between April 2000 and February 2001.[39] Puget Sound Energy accounted for 14% of the total (275,000 MW during 1958 hours), PacifiCorp for 13% (255,000 MW during 1,394 hours), Williams for 10% (192,000 MW during 1,749 hours), Arizona Public Service for 7% (133,000 MW during 843 hours), Idaho Power for 5% (91,000 MW during 927 hours), Sempra Energy Trading accounted for 4% (79,000 MW during 602 hours), and Enron accounted for 2% (45,400 MW during 793 hours).

Q. Were Scheduling Coordinators consistently engaging in Ricochet trades throughout the Full Period?

A. Yes. Table D-2 shows Ricochet transaction volumes by time period for each of the discussed time periods. While such single-party Ricochet transactions accounted only for 6,200 MWh for January 1 through April 30, 2000, the volume sharply increased to 846,000 MWh for May 1, 2000 through October 1, 2000. The volume of these single Scheduling Coordinator transactions remained high through the crisis period, accounting for 470,000 MWh during October 2, 2000 through January 17, 2001, and for 687,000 MWh during the CERS period from January 18, 2001 through June 19, 2001.

[39] Exh. No. CA-73.

Q. Please describe the results of your analysis presented in Table D-2.

A. During the "Summer" period (May 1, 2000 to October 1, 2000), about 846,000 MWh were simultaneously exported and re-imported by the listed individual entities. This is roughly 17% of total RT and OOM imports over this same period. PacifiCorp accounted for 221,506 MWh, Powerex accounted for 158,622 MWh, Puget Sound Energy accounted for 139,194 MWh, Arizona Public Service accounted for 99,000 MWh, Sempra Energy Trading accounted for 58,300 MWh, Idaho Power for 51,350 MWh, and Enron for 38,400 MWh.

During the early part of the "Fall/Winter" period (October 2, 2000 to January 17, 2001), 470,000 MWh were simultaneously exported and re-imported by individual entities. This is roughly 10% of total RT and OOM imports over this same period. Powerex accounted for 184,169 MWh or more than one-third of the total. Puget was the second largest user, accounting for more than 25% of the total.

During the "CERS" period (January 18, 2001 to June 19, 2001), 687,000 MWh were simultaneously exported and imported by individual entities. This is roughly 8% of total RT and OOM imports over this same period. Powerex accounted for 463,734 MWh or more than two-thirds of the total, and Williams Energy Services Corporation accounts for 169,852 MWh or approximately one quarter of the total for the sub-period. Together these two entities account for more than 90% of the identified single-Scheduling Coordinator DA/HA export and RT+OOM import transactions.

Q. The above discussion indicates the percentage of RT+OOM imports that were identified as potential Ricochet trades. Why is this important?

A. The analysis presented in Figures D-1 through D-6 shows a high correlation between DA/HA exports and RT+OOM imports, suggesting that Ricochet transactions account for a large percentage of the RT+OOM imports. The transactions identified as Ricochet trades in the above analysis account for only a small portion (10% to 17%) of the RT+OOM imports during the crisis period. This implies that there are a large number of Ricochets that are not identified by my analysis. Because my analysis can only identify potential Ricochet trades where the same entity is scheduling both the import and the export transactions (the so-called "one-party Ricochets"), I believe there are a large number of multi-party Ricochet transactions that exist, but cannot be identified using ISO and CERS data alone. These multi-party transactions are difficult to find because they are masked by the enormous volumes of trading activity in the Western market. Thus, I must

rely upon evidence produced in discovery to identify this type of multi-party Ricochets.

Q. Could some of the Ricochet trades you identified have been beneficial because they relieved congestion?

A. Possibly, although any potential benefit may have been outweighed by the harms described above. Since this hour-by-hour comparison matched exports from the California ISO control area to imports into the ISO, it is possible that some of these trades actually relieved DA or HA congestion without aggravating RT congestion. To explore this, I determined the portion of individual entities' potential Ricochet trades that were exported in the DA and HA markets on tie points that were congested in the import direction, and imported in the RT and OOM markets on tie points that were not congested in the import direction. These transactions comprise less than 1% (11,716 MWh) of the identified potential Ricochet trades over the May 1, 2000 to June 19, 2001 period. It therefore does not appear that single-party Ricochet trades relieved any significant amount of congestion.

Q. Do you have other evidence of the prevalence of Ricochet trades?

A. In addition to the analysis reported in Tables D-1 and D-2, I have been able to review materials produced through discovery in this proceeding. These materials provide additional evidence about parties involved in Ricochet strategies that help prove the intent of the parties. The following paragraphs describe the evidence of the participation in Ricochets by Reliant, Powerex, Sempra, Dynegy, and Mirant, among others.

Q. You noted in Part A of your testimony that Exh. No. CA-56 suggests that Reliant might have systematically pursued Ricochet trades by hiding the origin of its RT imports in cooperation with others. Please explain how this exhibit indicates such these "multi-party" Ricochet transactions.

A. The document provided by Reliant is an outline in 6 steps, I through VI. Step II refers to "camouflage transactions" with PNM, TEP and APS. Although the nature of the specific transactions in Step II is unclear at this point, the reference to "camouflage" may relate to Steps III or VI, as I will discuss shortly. The reference might also relate to the possibility that the three named utilities Public Service of New Mexico ("PNM"), Tuscon Electric Power ("TEP") and Arizon Public Service ("APS"), all of whom trade at the Palo Verde, AZ market hub just outside of CA, are the main participants in Reliant's export-import transactions as described in Steps III through VI. Of course, Step II might also refer to undescribed "camouflage transactions" that are independent of (and in addition to) the export-import transactions discussed in Steps III through VI.

Q. Please explain in more detail the transactions that are outlined in Steps III through VI of the exhibit.

A. The description of Reliant trades in Steps III through VI provides clear indication of a systematic infrastructure to execute multi-party Ricochet transactions:

- Step III of the Exhibit spells out that Reliant arranged for "Parking/Lending" services at two major export points—Palo Verde ("PV") and the California-Oregon Border ("COB")—for power generated from Reliant's "CA Unit Capacity." The parties providing the parking/lending services are not specifically named, but may be the utilities listed in Step II (PNM, TEP, APS). Reliant also indicates that parking/lending agreements in the Northwest involve transmission from Bonneville Power Authority ("BPA"), Portland General Electric, Shohomish ("SNO"), and Seattle City Light ("SCL").

- Step IV appears to lay out how parked power in the Southwest is moved from Four Corners ("FC") to PV, through "swaps" with APS, PACE, PNM, Salt River Project ("SRP"), or TEP, under which Reliant supplies the parked power at FC, and these entities (which presumably have transmission rights from FC to PV) return the power to Reliant at PV.

- Step V appears to describe an alternative "Power Swap" under which Reliant supplies power at one of four transmission interfaces with Los Angeles (likely in a transaction with LADWP), and receives power at PV.

- In Step VI.A, Reliant describes that it uses "a PV counterparty's name" to "submit a supplemental hourly bid at $250." This statement has several important implications: (1) Reliant is bidding its own power into the ISO RT market at $250/MWh (presumably the price cap active at the time the document was created); (2) Reliant hides its identity by bidding into the RT market using one of its PV counter parties' names; and (3) these PV counterparties (most likely PNM, TEP, APS, PacifiCorp ("PAC"), SRP, and possibly LADWP) must be active participants in Reliant's game, since they presumably pass any of the ISO's payments or charges on to Reliant.

- Steps VI.B and VI.C lay out that: (1) Reliant (using the counter-party name) submits a supplemental bid at the price cap; (2) if called upon, supply power at PV into the ISO's RT market when "called upon" by the ISO; or (3) generate "supply from units" uninstructed to receive the ex-post RT price, if RT dispatch from the ISO "is not available." (I discuss uninstructed generation strategies at the end of my testimony.)

- Finally, Reliant discusses some of the "problems" it might face in its attempt to hide the true nature of its transaction. First, Reliant might not be able to use its counterparties' name because the utilities might be active in the RT market on their own. Second, Reliant might not be able to run uninstructed its CA generating units simply because the "units might already be generating [at full] capacity." And, finally, Reliant has to pay the counterparty "for using their name" which increases Reliant's cost of arranging its "camouflaged" multi-party transactions.

Q. Does this Reliant document conclusively prove that Reliant actually pursued these "camouflage" transactions in a systematic fashion?

A. No, the document does not conclusively "prove" that. It is even conceivable that the document only lays out a strategy that was not actually implemented. However the existence of this document clearly corroborates the other evidence presented on the significance of MW Laundering. Even if Reliant did not actually implement this exact transaction, we do know that Reliant exported significant amounts of DA power out of the ISO's service territory. We also know that on an ISO-wide basis, the sharp increase in DA exports during the Summer and Fall of 2000, almost perfectly matched a simultaneous increase in RT (and later OOM) imports. These facts, together with the single-SC Ricochet analysis and additional evidence discussed below presents a compelling picture of the pervasive and systematic use of Ricochet by suppliers (generators and importers) in the CA power markets.

Q. Your analysis identifies Powerex as the seller with the highest number of potential ricochet transactions. How do you reconcile this with the fact that Powerex responded to the Commission's data request of May 8th, 2002 in Docket No. PA02-02-000 with a denial that it engaged in this type of transaction?

A. As I will explain, I cannot reconcile all of the statements Powerex has made concerning its export and import practices, including its response to the

Commission, with the data and communications discovered by the CA parties.

In many statements, Powerex claims that its primary strategy was to "optimize" its resources and provide for the needs of its system by purchasing power from the CA markets. In its PA02 response, Powerex says:

Powerex admits that it purchased power from the Cal PX and exported it from the California ISO grid, but denies that such purchases and exports were part of a practice of "taking advantage" of the price spread between price-capped California markets and uncapped markets outside of California. The vast majority of such exports were used to replenish BC Hydro's reservoirs, from which Powerex supplied the Cal PX and Cal ISO during periods of peak and super-peak demand. Such exports were part of the historical pattern of inter-regional exchanges between the Pacific Northwest and California. (Exh. No. CA-41 at 6).

Similar statements were made in background materials accompanying a February 21, 2001 press release by BC Hydro:

If BC Hydro has enough energy to meet domestic needs why import electricity? BC Hydro imports and exports electricity only after we meet the needs of our domestic customers. ... Our import/export strategy maximizes the value of our system without impact to the system or to customers. BC Hydro imports low-cost electricity at low-peak periods of the day (*e.g.* 2 a.m.) then that power is stored, as water, behind our dams until the peak period times of day (*e.g.* 6 p.m.) when that same power is exported back to utilities for a profit." (Exh. No. CA-39 at 4).

These statements clearly suggest that Powerex's CA export-import practices should have been to export from CA off-peak and to import into CA on-peak. If that were correct, one would expect Powerex to show the hourly purchase patterns consistent with Powerex's strategy (*i.e.*, DA purchases from CA during off-peak hours and DA or RT sales into CA during on-peak hours). Finally, note that Powerex's assertion that it did not engage in Ricochets would be technically correct only if it turned out that its DA exports and RT/OOM imports always occurred during different hours (*i.e.* exports off-peak and imports on-peak), so that there were no simultaneous Ricochet-type DA export and RT import transactions.

However, neither email communications discovered from Powerex nor ISO data comport with Powerex's export-import assertions. First, an email from

Powerex employee Murray Margolis on December 11, 2000 notes that "we are currently buying out of CA around the clock to match our forward transmission purchases (115 MW WAPA, 50 Redding, 200 Lugo) and we are buying additional energy in Hours 1-5 and 11-16 and then plan to sell hours 6-10 and 17-21 (we will then not have a conflict with 'buying' and 'selling' at the same time)." (Exh. No. CA-38 at 3).

This email seems to suggest that instead of shaping its purchases to be off-peak and its sales back to be on-peak, Powerex is buying CA power "around the clock" *in addition to* making hourly purchases during certain hours (note that hours 11-16 are also not off-peak hours), so already there is some discrepancy between this email and stated practices. If it were the case that these "around the clock" purchases were from the PX, and the sales back during hours 6-10 and 17-21 were sales to the ISO in RT or OOM, then these transactions were the exact equivalent of a Ricochet-type trade, with the adverse effects as described in Section II above.

An examination of Powerex's purchases from the PX suggests that this pattern indeed was the case during many periods, including system emergencies. (I discuss behavior during emergencies further in a moment). Similarly, Exh. No. CA-38 at 2 shows Powerex's final schedule of PX sales and purchase for December 13, 2000. On this day, Powerex not only bought from the PX, it bought *greater* net amounts on-peak than off-peak – the exact opposite of its stated strategy. A review of Powerex's net PX purchases and sales each day during August and December shows that Powerex often purchased as much or more on-peak PX energy as it purchased off peak. (See Figures D-7 in Exh. No. CA-2, Appendix D).

Data obtained in discovery also indicate that Powerex was a very large seller of power back to the ISO in RT. In September, 2000, Powerex's own assessment of its sales to the ISO found that it accounted for 44% of the entire month's RT sales (Exh. No. CA-189 at 1). In November, 2000 Powerex's own estimate of its RT market share estimate was 79% (Exh. No. CA-189 at 2). Similarly, Exh. No. CA-73 shows that from April 2000 through February 2001, Powerex sold to the ISO a total of 3.8 million MWh, earning $891 million in revenues.

Finally, Powerex's internal strategy documents discuss arbitrage between the PX and ISO markets (Exh. No. CA-45 at 3) – a benign description of many Ricochet-type trades. The same document also specifies as one of the responsibilities of its California ISO/PX activities the "optimization between different California markets (DA, HA, Supplemental, Ancillary and out of market)". Similarly, the "2000-01 Business Plan" for Powerex

traders (Exh. No. CA-49) evidently assigned to the CA market included the objective: "Increase Powerex exposure to imbalance markets during price spikes." The way in which this was to be done was to "analyze the DA vs. Expost, overschedule to load, bypass congestion on NW ties. Encourage arbitrage desk deals with CAISO."

In short, these data simply do not square with Powerex's stated strategy or its answer to the Commission in PA02-2-000. Instead, it appears that Powerex bought extensively from the PX and sold extensively back to the ISO in RT or OOM. This is exactly what my data screen identifies: hours in which one scheduling coordinator is both exporting from the PX market and simultaneously importing to the ISO market. To the extent that Powerex sleeved its purchases from or sales into CA through third parties (such as documented in Exh. No. CA-320), my analysis may significantly understate the magnitude of such trades.

There is a further apparent discrepancy between Powerex's stated strategy and its public explanations of these strategies during December, 2000 (at least as the latter was reported in emails). In December, Powerex stopped selling to the ISO as it became concerned over the ISO's credit. Apparently in response to an ISO inquiry for emergency power, a December 13, 2000 Powerex email (Exh. No. CA-38 at 1) states:

"The ISO phoned today asking for additional supply. Since the Cal IOU's brought credit to the media's attention, 12 other companies have stopped selling. If the lights go out in California it will not be Powerex's doing. We are selling to the CAL PX as we can. We are not increasing our financial exposure as we have purchases from the ISO. If the ISO phones do not panic. I don't believe Powerex alone can stop the lights from going out. We will not be increasing the credit limit to the ISO. I will advise the ISO we are selling into the CA market as we can through the PX."

Note that this email states that Powerex will "advise the ISO we are selling into the CA market as we can through the PX." However, as Exh. No. CA-38 at 2 shows, on that very same day Powerex was exporting out of California via DA market purchases a total 26,213 MWh, exceeding 1,000 MW in many hours.

If Powerex did advise the ISO as such, this was a misleading claim. As just noted, Powerex was primarily a buyer, not seller, in the PX market. It is true that Powerex transitioned out of the ISO markets as a direct seller starting in December, 2000 as credit concerns arose. However, Powerex began selling large amounts of real-time energy back into the CA markets

through intermediaries, especially CERS, in January and February 2001. (CA-73, see also Exh. No. CA-320) From January to May, 2001, Powerex sold CERS $1.05 billion in power in the RT market, which it calls the "last minute" market (Exh. No. CA-39 at 9), apparently "charging double the market at times" (Exh. No. CA-44).

In short, whatever words Powerex has chosen to describe its activities, the data indicate that Powerex was both importing and exporting during the same hours in very large quantities, and that the exports from CA were not in RT while the imports were. This is the clear economic signature of a Ricochet-type trade.

Q. Your analysis shows that Powerex was very heavily involved in export-import transactions. Does the fact that they are a foreign company raise any special issues?

A. Yes. Powerex is operating pursuant to a license that prohibited the company from exporting power from the US in ways that could impair system reliability (Exh. No. CA-63). Table D-3 shows Powerex's net exports from the ISO to the Northwest during ISO emergency conditions. In emergency hours from December 2000 through May 2001, Powerex exported more than 230,000 MWh from California into the Pacific Northwest. This energy purchased out of California was either exported to Canada or sold to others.[40] If this power is being exported to Canada, this could represent licensing violations. On the other hand, if this power was being sold in the Northwest, it could easily be "flipped back" to the ISO or CERS as part of a multi-party Ricochet transaction.

Q. Is there any evidence that California power was actually exported into Canada?

A. Yes. In Exh. No. CA-41 at 8, Powerex certifies under oath that "96.8% of the energy purchased by Powerex from the CAL PX in the DA market during such periods was transmitted to the BC Hydro[41]

Q. What evidence do you have of Sempra's Ricochet activity?

A. Table D-1 indicates that Sempra was likely involved in more than 800 hours of Ricochet transactions during the period from May 20, 2000 through June 19, 2000. Materials found in Sempra's discovery production

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[40] One-party Ricochets where the power exits and re-enters in the Northwest are netted out of the data in Table D-1 and D-2. The possibility exists that these sales may be looped around to the southwest and re-imported as part of one-party Ricochets. However, I find this possibility unlikely for any significant volume of transactions.

[41] Also note that Exh. No. CA-38 at 3 shows that Powerex bought significantly more energy (a total of 26, 213) on that day. The addition energy would have been sold in the Northwest or reimported back to the ISO.

help to complete the picture of Sempra's Ricochet activities. For example, parking arrangements with PNM (Exh. No. CA-69 and CA-70) and Eugene Water and Electric Board ("EWEB") (Exh. Nos. CA-68) allowed Sempra to park DA or HA export schedules in the PNM and EWEB control areas. As compensation for providing this parking service, Sempra would pay PNM and EWEB a fixed monthly reservation payment of about $40,000 to $90,000 per month, plus, for EWEB, a variable charge of $1 to $6 for each MWh parked.

Q. Is Sempra involved in multi-party Ricochets?

A. Yes. The review of discovery materials provides a clear example of a multi-party Ricochet trade between Sempra, Dynegy and PacifiCorp in March 2001. A Sempra internal email from March of 2001 indicated that Sempra was "buying NP15 and doing a B/R with DYPM selling them NP15 and buying back COB SN on their transmission for $20, then bouncing off PAC for $20 and selling hourly to CERS." (Exh. No. CA-188). This clearly refers to a "buy-resale" transaction in which power purchased within the NP15 system is scheduled out of the ISO through Dynegy (DYPM), then "bounced off" PacifiCorp (PAC), and subsequently sold to CERS on an hourly basis. Such multi-party Ricochet transactions are not captured in my previously-discussed single-par analysis.

I have used the blue print for these transactions provided in this Sempra email to find the corresponding transactions in the Sempra trading records (Exh. No. CA-94), which were matched with information obtained from the ISO and CERS to determine that the export from the ISO was conducted by Dynegy. The Sempra trade book data confirms the following trades associated with the above-described Ricochet transaction path between Sempra, Dynegy, and PacifiCorp. For example, on March 8, the trades included the following:

- **Step 1**. Sempra sells 1,814 MWh of firm power to Dynegy at NP15 at $300/MWh.

- **Step 2.** Dynegy sells 1,814 MWh of firm power to Sempra at COB SN (south to north) at $320/MWh.

- **Step 3.** Sempra sells 1,814 MWh of firm power to PacifiCorp at COB SN at $300/MWh.

- **Step 4.** PacifiCorp sells 1,814 MWh of firm power to Sempra at COB NS at $320/MWh. (Note that this is the same point, COB, but

the energy has been "ricocheted" off of PacifiCorp and is now moving south into California as reflected in the reference to the delivery point. COB NS is the same point as COB SN, but the energy is moving south so that it can be sent back into the ISO.)

- **Step 5.** On that particular day, Sempra sells a total of 7,486 MWh of firm power to CERS (noted as California Department of Water Resources). The data also shows that Sempra was selling more to CERS than the volume that was part of this particular Ricochet transaction. The average price of these sales was $376.81/MWh. I have also calculated a weighted average price of $377.98/MWh for sales to CERS during the hours when these 1,814 MWh were sold.

This trade illustrates the potentially serious harm that Ricochet transactions can have. I have reviewed Sempra's trading book to find transactions that occurred at NP15 for delivery on March 8, 2001, the same date and location at which Sempra bought the power that was used to transaction the above Ricochet. From this data, I find that Sempra's purchases and sales prices ranged from $155/MWh to $220/MWh. This data suggests that Sempra's gross margin was probably at least $158/MWh for the Ricochet ($377.98 MWh average realized CERS sales revenues *less* $220/MWh, the highest price at which Sempra sold power at NP15 on that date). This difference results in a total gross margin of at least $287,000 on this trade. While this gross margin does not include transaction costs such as transmission, this amount represents the total overpayment by the ISO market. By "re-labeling" ISO-internal power as an import, Sempra was able to mark up the cost of this power to the California markets by 72%, or $287,000.

Q. Was this transaction a one-time event?

A. No. The Sempra trading book data indicates that within-day export-import transactions were a fairly common occurrence during March 2001. A review of the trading data indicates for March 2001 that Sempra conducted other Ricochet trades using Dynegy and PacifiCorp in at least 11 instances, "bouncing" more than 15,000 MW. (See Table D-4). The trading books for Dynegy and Sempra also show that these parties engaged in the same strategy many times throughout April and May 2001. Despite these many examples of Ricochets by Sempra, the company denies engaging in Richochet deals in its PA02-2 filing with the Commission. (Exh. No. CA-217 at 7 to 9)

Handwritten trader notes produced by Dynegy also confirm repeated buy-resell transactions between Sempra and Dynegy during March 2001. (Exh.

No. CA-122) For example, the March 8, 2001 transaction is shown on page 37. The Dynegy trader notes also indicate that Dynegy was also involved with Buy-Resell transactions between NP15 and COB (the same route as the Sempra example above) with other entities, including Enron (at 37) and SHPD (Snohomish Public Utility District, at 42), suggesting that it may have been involved with other Ricochet games (at 42).

Q. What evidence exists that Mirant was engaging in Ricochet activity?

A. The analysis in Table D-1 indicates that Mirant was involved in more than 130 hours of export/re-import transactions during the Crisis Period. As discussed in Part A of my testimony, Mirant also was one of the main exporters of DA power during the Summer of 2000, and one of the main OOM importers of during the Spring of 2001. Both the earlier DA exports and the later OOM imports could potentially be part of individual "legs" in multi-party Ricochet transactions. However, records produced by Mirant provide specific evidence of the company's participation in Ricochet-type trades.

For example, an internal Mirant email from March 2001 describes a transaction in which Mirant took power from the ISO, scheduled that power out to the Pacific Northwest, where it was parked with Seattle City Light ("SCL") in a buy-resell transaction. It was then re-imported into the ISO service territory, where it was sold to CERS. This "one-party" Ricochet trade yielded Mirant a margin of $45/MWh (even after paying SCL a $15/MWh parking fee). The email reads:

> *we were long about 500 MW today during the peak. we didn't see better than $215...we sold to the hourly cash book at malin. mike then sold to scl and bought it back, so essentially parked it with them for $15. so we made money selling to the hourly book, then the hourly book made money ($45 margin) selling to cers at malin. scl bought the transmission on both legs. for those wondering why we don't just sell at malin to cers off our generation is because apparently energy can't make u-turns at interties. so you have to make the u-turn at a pse, in this case scl. sssssuper! (Exh. No. CA-333 at 1)*

I also note that Mirant's PA02-2 response indicated that Mirant engaged in numerous buy-resell transactions with SCL, as well as some with Public Service of Colorado. (Exh. No. CA-281) These buy-resell transactions may well be additional Ricochet trades.

Q. Is there any evidence indicating that Mirant was also involved in multi-party Ricochets?

A. Yes. Documents produced in discovery suggest that Mirant may also be participating in multi-party Ricochet trades. In particular, Mirant frequently is a participant in "flipping" transactions, where power is purchased from one marketer, "flipped" at an export point (such as Malin), and then immediately resold to CERS at significant markups. These purchases often are made from entities able to sell to CERS on their own, yet they are willing to allow Mirant repeatedly to act as a middle man and earn a significant margin. For example, in the Spring of 2001 Mirant frequently appears to be selling southern-California power to Powerex. (Exh. Nos. CA-137, CA-319 and CA-321) During the same period Mirant also was purchasing significant amounts of power from Powerex in the Northwest and reselling it to CERS. In April of 2001, Mirant was purchasing 1,200 MWh from Powerex and reselling it to CERS at a margin of $50/MWh, earning $60,000 per hour (Exh. No. CA-320 at 1). This $50 margin is roughly equal to the full production cost of power in normally-functioning market conditions. Other examples cited in Mirant emails of "flipping" transactions that are consistent with export-import games include:

- "We did a great number of trades during the evening, buying energy mainly from AEMC and EPMI and flipping it to CERS. Came away with a good deal of dinero for two consecutive nights." (Exh. No. CA-140)

- "continued malin deal with aemc and flipping to CERS (Exh. No. CA-322)

- "Continued to sell power to CERS at Malin for most of the Off-Peak from AEMC and EPMI and made some good margin on the trades." (Exh. No. CA-318)

- "flips at malin with aquila to cers." (Exh. No. CA-317, April 2001)

- "flippin has made us mad benjis this morning." (Exh. No. CA-323, April 15, 2001)

Q. What evidence do you have that other sellers likely were involved in Ricochet transactions?

A. In addition to Powerex, Sempra, Dynegy, and Mirant, documents produced in discovery provided evidence of the participation of other Scheduling Coordinators in Ricochet transactions:

- **Enron.** Figure Ricochet 1 finds that Enron was the eighth largest user of one-party Ricochet transactions between May 2000 and June 2001. Ricochets were disclosed as a strategy used by Enron in the Enron December 6, 2000 memo (Exh. No. CA-78). An update issued sometime after the December 6, 2000 memo indicates that this strategy was used more commonly by entities other than Enron. (Exh. No. CA-79 at 4) An example of an Enron Ricochet transaction is presented in an internal Enron email that describes a new path for exporting power from the ISO over the Silverpeak line and "bounc[ing] this of [sic] SNOHO before we send it back in at Malin." (Exh. No. CA-145 at 1351). Enron documents also identify a potential Ricochet-type trading strategy called "Round the West," which involved scheduling "California power out in the Southwest, up the Rockies, across MPC or IPC, down through MIDC, and back into California."[42] (Exh. No. CA-145 at 1210)

- **Constellation Power Source ("CPS") and LADWP.** The ISO maintains a Non-Compliance Report in which it reports suspicious activity. On November 11, 2000, the ISO's Non-Compliance Report cites an incident in which CPS and LADWP were involved in a "ricochet schedule off Malin tie." In its report, the ISO notes that LADWP has been involved in Ricochet schedules in the past, indicating that "LA is up to its old tricks again." (Exh. No. CA-128)

- **Glendale Water & Power and Coral.** Traders for Glendale appear to maintain a document that explains various trading strategies, many of which would be implemented with Coral Energy. One of the strategies included on this document is for Glendale to "[l]ook to utilize park and loans with counterparties such as PNM (PV) and Pueget [sic] (Mid-C) in the DA Market, and utilize the energy in the expost and ancillary services markets in the ISO." The sheet refers to a "Parking Road Map" which has not been produced to date. (Exh. No. CA-168)

- **PacifiCorp.** As described above, PacifiCorp provided a parking (or "buy-resell") service for the Ricochet transaction that involved

[42] When subpeonaed to discuss documents related to this transaction and other Enron games, he indicated that, if deposed, he would take the Fifth Admendment.

Sempra and Dynegy on a number of occasions. A call between a PacifiCorp trader and an Enron trader on August 23, 2000 indicates that PacifiCorp knew, or should have known, that its parking service was being used to engage in Ricochet transactions. The Enron trader tells the PacifiCorp trader the entire trade. It is a buy-resell transaction between Enron and PacifiCorp, with the power "coming from the PX and going to the ISO," a cookie-cutter Ricochet transaction. The conversation proceeds as follows:

SPEAKER 1: PacifiCorp. This is Todd
SPEAKER 2: Hey Todd. This is Stan, From Enron.
SPEAKER 1: Hi Stan.
SPEAKER 2: Hey, I was wondering, uh, for hour ending one, uh, would you guys be able to do a buy-resell at Malin, with us, for a hundred megawatts?
SPEAKER 1: Uh, yeah, I could do that.
SPEAKER 2: Okay. It'll be coming from the PX and going to the ISO.
SPEAKER 1: Okay.
SPEAKER 2: You still doing five bucks on the uh, on the charge there?
SPEAKER 1: Yeah.
SPEAKER 2: Okay.
SPEAKER 1: Let's use the hundred and, hundred and five?
SPEAKER 2: Uh, w- sure. That'd be, that'd be fine.
SPEAKER 1: Okay. You said a hundred megawatts, right?
SPEAKER 2: Correct.
SPEAKER 1: Okay. All right, I'll put it in.
SPEAKER 2: Thanks Todd I appreciate it.
SPEAKER 1: Uh-huh.
SPEAKER 2: Bye-bye.
(Exh. No. CA-179)

Documents provided by Enron show that this type of buy-resell transaction between Enron and PacifiCorp was a very common occurrence. (Exh. No. CA-74)

- **Williams Energy Services Company.** Williams was identified as the fourth largest user of single-party ricochet trades. A January 1999 email from Harvey Hall to Timothy Belden at Enron attaches a spreadsheet of "ricochets related to Williams." (Exh. No. CA-76 at 1) While the name suggests that these are Ricochet games, given the

timing and the lack of discussion in the email, however, the potential exists that this email is referring to other strategies.

Q. Do you have any evidence about the prevalence of parking services that can be used to effectuate Ricochet transactions?

A. Yes. The widespread provision of parking services suggests that the ability to engage in Ricochet strategies is common. A list of entities known to offer parking services includes: APS, EWEB, El Paso Electric, Grant County, PacifiCorp, Pasadena, PNM, Portland General Electric, Puget Sound Energy, Riverside, SCL, Snohomish, TEP, and Avista Corp. (formerly Washington Water Power).[43] A spreadsheet produced by PNM shows companies to whom it sold parking services during the period from January 2000 to June 2001: Aquila, CPS, El Paso Merchant, Enron, Idaho Power, Koch, MEICO, Morgan Stanley, PECO, PacifiCorp, Powerex, Sempra, and TransAlta. (Exh. No. CA-187). EWEB, in negotiations with Sempra over a parking agreement, discloses that it is already providing this service to "3-4 different clients." (Exh. No. CA-65 at 1).

Finally, I note that a presentation by Jimmy Lin of LADWP dated March 30, 2001 notes how commonly parking services were used to facilitate Ricochet transactions: "Generators wheel the power out of the State, park it and resell back to take advantage of ISO's out-of-the-market calls. OOM calls are not subject to price caps." (Exh. No. CA-82 at 34).

Q. Do you have other concerns about these parking and buy/sell services?

A. Yes. At least in some circumstances the transactions are to transmission arrangements. For example FERC has held that certain buy/sell transactions on the PacifiCorp system should be treated as transmission service. However, for FERC regulated utilities, transmission arrangements are subject to strict pricing requirements under open access tariffs and strict rules concerning the way in which such transactions will be publicly requested (Order 889). In contrast, buy/sell agreements that are the equivalent of transmission have no pricing or access limits whatsoever.

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[43] APS and TEP (Exh. No. CA-56); EWEB, Puget, SCL, Snohomish, and Avista (Exh. No. CA-67); Grant (Exh. No. CA-134); Pasadena (Exh. No. CA-123, note that this document does not confirm whether or not this transaction was every consummated); Riverside (Exh. No. CA-89); Portland General (Exh. No. CA-150, CA-327 and CA-320); El Paso Electric (Exh. No. CA-105 110-116).

This incentive to buy up transmission and resell it as bundled location-specific power at prices much higher than would occur if the bundled transmission was sold at its regulated rate

IX. CONGESTION-RELATED STRATEGIES: CUT SCHEDULES AND LOAD SHIFT

A. Introduction

Q. What types of strategies fall into congestion-related games?

A. Congestion-related games are strategies that seek to profit from the relief of congestion. The strategies include "Death Star", "Cut Schedules," and "Load Shift" games, among others. The common element among these congestion strategies is that they schedule counterflows that earn payments for relieving congestion without actually providing any congestion relief.

B. DEATH STAR

Q. What are Death Star strategies?

A. Death Star, the other prominent export-import strategy, was designed to game the ISO's congestion management system. This strategy, sometimes known as a "circular schedule" uses two back-to-back transaction schedules that simultaneously export and re-import the same power on a DA (or possibly HA) basis. One schedule imports power to the ISO through one transmission interface. This "moves" it over a constrained transmission interface controlled by the ISO in a direction opposite to congestion and exports the power over a second transmission interface. This relieves some of the congestion on that constrained interface and earns a payment for this "counterflow." (The constrained interface may be the import point, the export point, or a transmission interface internal to the ISO, such as Path 15.) A second schedule then "moves" the same power around outside the ISO (over transmission lines that are not "seen" by the ISO) to complete the circle and connect the export point with the import point. As a result of this circular schedule, in Enron's own words, "[n]o energy. . .is actually put onto the grid or taken off."[44] Moreover, no power will actually flow in most of the cases.

Because the second half of a Death Star transaction occurs on transmission capacity beyond the view of the ISO, it does not know that the trade is circular, and thus self-canceling. Therefore, it believes that congestion has been relieved and makes congestion payments to the scheduling coordinator, even though no relief has been provided. This strategy is

[44] December 6, 2000 Enron Memo (Exh. No CA-78).

dependent upon the fact that the ISO cannot know that the transaction is circular.

Q. Enron used the term Death Star to describe transactions over certain transmission paths. Do you use the term in the same manner?

A. In some cases, including the Enron memos, the term Death Star is used to describe a specific circular path involving the AC intertie and certain ties to the Southwest. I use the term to refer to any circular trade entering (and therefore exiting) the CAISO system that employs a matched transmission link outside its control area. In addition, there can be Death Star games entirely within the ISO.

Q. How do Ricochet and Death Star games differ?

A. There are two key distinctions between Death Star and Ricochet games. The first difference is in the types of paths used in the two strategies. Death Star is intended to be circular, conjoining two different contract paths with reversed origins and destinations (*e.g.*, entering the ISO in the Southwest, flowing through the ISO, exiting into the Northwest, and circling around the ISO to the starting point Southwest). Ricochet-type trades generally, but not necessarily, follow similar paths out of and in to the California ISO (*e.g.,* exporting from the ISO to the Northwest, and re-importing from the Northwest to the ISO). The second difference is in the timing of the trades under the two strategies. Death Star strategies could involve two transactions (one on the California ISO system and one on a neighboring system) scheduled on a DA or HA basis, while Ricochet strategies involve one transaction (an export) scheduled DA or HA and one transaction (an import) scheduled in RT.

Q. What is the economic impact of the use of Death Star strategies?

A. In isolation, and subject to the caveats discussed above, Death Star and other circular trading schemes had several economic impacts. First, they created congestion relief payments without actually providing congestion relief. Since the DA and HA congestion relief that was paid for in these trades did not physically materialize as the operating hour occurred, the ISO may have needed to pay for RT congestion relief raising RT prices.

In Enron's own words, "[t]he net effect of these transactions is that Enron gets paid for moving energy to relieve congestion without actually moving any energy or relieving any congestion." (Exh. No. CA-78 at 5)[45]

[45] The confidential (non-public) report on Enron trading strategies by Eric Hildebrandt of the California ISO's Department of Market Analysis titled "Analysis of Trading and Scheduling Strategies Described in Enron Memos" and dated October 4, 2002. This report notes that it is conceivable that a Death Star trade

Q. Please describe the reliability harm that is caused by the use of Death Star transactions.

A. There were likely reliability impacts from the use of Death Star. Security coordination requires an accurate set of schedules. For example, when a portion of the system faces overload, security coordinators must order a reduction in load and generation, often by cutting schedules. For a circular schedule, if the security coordinator cuts the export from the California ISO's system, it may trigger a responsive cut in the source for a matching import into the ISO's system. This could defeat the reliability purpose of the original export cut. In addition, absence of the flow in RT will cause the ISO's RT operating assumptions to be incorrect.

The harmful consequences Death Star on reliability are detailed in an October 2002 report by Eric Hildebrandt of the ISO's DMA group (the "October 2002 ISO Enron Strategies Report").[46] In addition, these concerns are documented in email exchange between ISO personnel. On November 16, 2000, Joe Binstein wrote "congestion scam" noting that Sempra had apparently scheduled a Death Star going into the ISO at Mead and out at Four Corners (collecting congestion from this flow) and then going between Mead and Four Corners (outside the ISO) on APS transmission. The email notes that "the only thing being generated here is the $45/MW congestion revenue":

> *For HE 1400 today SETC was awarded 75mw in at MEAD and out at FCORNR by congestion management. Then SETC purchases 74mw OASIS transmission from APS from FCORNR to MEAD. We think we are wheeling 75mw, APS thinks they are wheeling 75mw. When you ask SETC who is generating the 75mw they say it's APS, and if you APS they'll tell you they're just wheeling ISO generation. The only thing being generated here is the $45/mw congestion revenue for SET at FCORNR. Please take a look. (Exh. No. CA-132)*

Q. Could the schedules that appear to create Death Star transactions be the result of unintentional trading activity?

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would ultimately relieve some congestion in the Day Ahead and Hour Ahead markets due to the fact that the California ISO portion of the transmission scheduled for the circle would allow the ISO to divert some energy that is scheduled on congested ISO paths to transmission lines outside the ISO. However, the report also notes that ISO grid operations staff do not agree that circular schedules actually relieve congestion, since the ISO's congestion management system is a simplified model of electrical flows that is based on "contract paths" and does not reflect actual loop flows. (Exh. No. CA-109 at 8)

[46] October 2002 ISO Enron Strategies Report (Exh. No. CA-109 at 8)

A. Probably not. There is little question that a pre-arranged, matching circular trade was an intentional act. Although it is conceivable that a Scheduling Coordinator might not have realized that two independent transactions create a circular trade, in most cases it is nearly inconceivable that a Scheduling Coordinator would not keep track of its regional schedules well enough to know that a circle had been scheduled. Thus, a schedule that included a known circular trade that was counted on and paid for relieving DA or HA congestion constituted the intentional submission of a DA or HA schedule would, in my opinion, be intentionally deceptive to the California ISO. I note that these economic and reliability harms should have been reasonably foreseeable to a Scheduling Coordinator.

C. EVIDENCE REGARDING SPECIFIC SELLERS – DEATH STAR

Q. Have there been any analyses of the prevalence of Death Star games?

A. Yes. The October 2002 ISO Enron Strategies Report (Exh. No. CA-109) produced an estimate of the total congestion revenues earned through possible single Scheduling Coordinator Death Star trades by identifying matching export/import schedules of equal quantities by the same entity. The ISO calculated the entities' congestion revenues from such counterflows on interties and any internal paths within the ISO.[47] An addendum to this report (Exh. No. CA-109) was released on January 17, 2003 (Exh. No. CA-108) revised this initial estimate of the total congestion revenues earned through such potential Death Star trades by single Scheduling Coordinators.[48]

Q. Are there any limitations to the ISO's study?

A. Yes. Neither the ISO nor I can prove that the potentially circular schedules identified are actually circular using available data. This is because we do not have access to complete enough records to check on the portion of the circular transmission path outside the CAISO. Thus, some of the potentially circular trades are undoubtedly not actually circular. Conversely, however, the ISO's analysis is conservative in that it does not attempt to locate circular trades involving more than one Scheduling Coordinator, and it omits circular trades in which one Scheduling

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47 See October 2002 ISO Enron Strategies Report (Exh. No. CA-109 at 8-11).

48 This revised analysis differs from the analysis reported in the October 2002 ISO Enron Strategies Report in several significant ways. Most importantly, the revised analysis incorporates Existing Transmission Contracts ("ETCs") and accounts for the fact that entities that hold ETCs on a tie point or path do not earn congestion revenues or pay congestion charges. The ISO assumes that if a Scheduling Coordinator held an ETC on any leg of a circular schedule, then that entity would earn no congestion revenues and pay no congestion charges for all legs of the circular schedule.

Coordinator used two separate schedules. For example, since the ISO's analysis identifies circular schedules by matching quantities, it would not detect a circular schedule that involved a 50 MW export and two 25 MW imports. The analysis is also likely to significantly understate the magnitude and frequency of Death Star-like schedules because, as noted above, it did not consider circular schedules facilitated by certain California utilities, such as LADWP, MID, and Glendale, that are not part of the ISO. The analysis further understates the likely magnitude and frequency of circular trades because it does not identify circular transactions involving more than one Scheduling Coordinator. In this regard, the ISO's analysis is highly conservative and will likely understate the use of this gaming strategy.

Q. Do you agree with the results of the ISO's analysis?

A. Yes. I have quantified the volume and frequency of potential Death Star transactions based on a replication of the ISO's revised analysis.[49] Though the ISO analyzed all circular schedules that are possible Death Star trades between 1998 and 2002, I focus my analysis on the four previously-discussed periods during the January 2000 through June 2001 time frame (the Spring of 2000, the Summer 2000 period, the early part of the refund period during Fall and Winter 2000, and the CERS period of January-June 2001). I have also eliminated certain schedules that were double counted in the ISO's analysis.[50] My analysis is subject to the same methodological caveats and conservatisms as the ISO's study.

Q. Please describe the results of this analysis

A. My replication of the ISO's analysis finds that 19 Scheduling Coordinators engaged in potential Death Star trades between May 1, 2000 and June 19, 2001. Among these, four had potential Death Star trades totaling more than 5,000 MWh: Coral Power, Enron, Sempra Energy Trading, and Morgan Stanley Capital Group. These results are summarized in Table E-1.

Table E-2 compares the volume of potential Death Star transactions by Scheduling Coordinator across four time periods. This comparison shows that the magnitude and frequency of these potential Death Star transactions were similar in the Spring and Summer 2000, but significantly higher during the Fall and Winter of 2000.

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[49] The ISO provided workpapers for its revised Death Star analysis in response to Data Request CAL-ISO-17.

[50] The ISO stated in its revised Death Star analysis that the analysis double counts congestion revenues from certain schedules, but noted that such double counting involves only a small number of schedules.

The existence of actual Death Star and similar circular transactions is also strongly suggested by some of the interchange ID codes used by the Scheduling Coordinators identified by my analysis. For example, Enron frequently marked the export and import legs of the here-identified transactions with names such as "EPMI_Star" and "CISO_Death" and similarly colorful combinations such as "Curious" and "George", "Red" and "Green", "Hungry" and "Hippo", "James" and "Dean", or "Chinook" and "Atlantic." Similarly, some of the identified transactions for Mirant use the phrase "SCEM_Loopy" in their interchange ID codes. (See Table E-3.) The interchange ID codes used by other Scheduling Coordinators are not obvious enough to provide, by themselves, additional confirmation of the likely circularity of the identified potential Death Star-like transactions.

Q. Above you stated that the analysis identified schedules where the import and export volumes for a Scheduling Coordinator were identical in an hour. How do you know that these are circular schedules?

A. Neither the ISO nor I have conclusively confirmed the actual circularity of all identified schedules. As the ISO points out, NERC tagging information was insufficient in most cases.

Q. What evidence do you have of the use of Death Star games other than the results of this analysis?

A. In my review of discovery materials, I have identified a number of instances that clearly expose Death Star-type games employed by a number of sellers, including both power marketers as well as municipal utilities. These implicated entities include: Enron, Avista, Portland General Electric, PacifiCorp, Redding, NCPA, Modesto Irrigation District ("MID"), City of Glendale, Mirant, Duke, Sempra, and LADWP.

Q. What evidence do you have of Enron's use of Death Star games?

A. The analysis presented above indicated that Enron was the largest user of Death Star strategies, with nearly 25% of all incidences between May 2000 and June 2001. Enron's use of this strategy is consistent with the information provided in documents produced in this proceeding. For Enron, there were multiple variants of this game bearing names such as the "Forney Perpetual Loop," "Red Congo," and "NCPA Cong Catcher." The notes describing the Forney Perpetual Loop indicate that "no MW's flow" as part of the transaction. (Exh. No. CA-145 at 624) Mary Hain of Enron referred to the use of ETC transmission as "we ride in the highway lane not owned by ISO…owned by muni." (Exh. No. CA-93 at 225). This strategy was in use by Enron prior to May of 2000, with an internal document indicating that it had been successfully used to capture congestion relief

across Path 26, Path 15, and COI. (Exh. No. CA-145 at 625) Further, Enron trading logs indicate that Death Star strategies were used frequently. (Exh. No. CA-74)

Q. How does the Forney Perpetual Loop work?

A. The Forney Perpetual Loop involved a transaction between Enron, Portland General Electric, Avista, and one or more transmission providers able to complete the loop into the southwest CAISO entry point, such as LADWP. In these transactions, power is exported from the California ISO and subsequently re-imported using the following loop: Enron Export from ISO→Avista→Portland General Electric →transmission provider such as LADWP→ISO. The ISO was the source of the power (it was exported at Malin) and the ISO is also the ultimate sink for the transaction, but Enron does not want that known. (Exh. No. CA-145 at 624) Enron structured this transaction in such a complex manner because Enron doesn't want the transaction "to look like a Ricochet." (Exh. No. CA-106 at 908)

Q. Were the other parties involved complicit in this strategy?

A. This and similar transactions are discussed in trader tape transcripts appended to Portland General Electric's filing in Docket No. PA02-2. The complicity of Portland General Electric and Avista employees in these transactions is highlighted by their comments in which they call the transaction "weird," "bogus," and a "scam." There are also internal Portland General Electric discussions even questioning the legality of the transaction because it is also clear that both Portland General Electric and Avista know that Avista was inserted into the transaction as a "sleeve" between Enron (Exh. No. CA-106 at 274-5) and Portland General Electric to evade Commission restrictions on Enron-Portland General Electric dealings. It is less clear to me how much LADWP knew about this transaction, but, as described later, I believe they were aware at least at a high level because, as discussed later, LADWP was tracking "phantom congestion" revenues.

Q. What is Red Congo?

A. Red Congo is described in Enron documents as "flow[ing] a virtual loop to relieve congestion…free money." It is the same type of transaction as the Forney Perpetual Loop, but it uses different parties and a different transmission loop. Other Enron documents appear to say that in this transaction, Enron buys from Redding, sells to PacifiCorp, which marks it up and sells it back to Enron. (Exh. Nos. CA-145 at 1225 and 1320-1)

Q. Did PacifiCorp and Redding understand their roles in the Red Congo scheme?

A. I believe so. I have identified an internal Enron document discussing this Red Congo that states "Redding is on board with this strategy, as is PacifiCorp." (Exh. No. CA-145 at 396). In fact, in April 2000,[51] Paul Cummings at Redding created a memo called "042800 Congestion.doc." This memo confirms that Redding was fully aware of the entire transaction as well as its intent to earn congestion on the California-Oregon Intertie ("COI"). Mr. Cummings also explains the pricing of the transaction circle, indicating that Redding understood the terms of the transaction.

Q. How does NCPA Cong Catcher differ from other Death Star schemes?

A. NCPA Cong Catcher appears to be another variant of Death Star designed to "catch" congestion relief revenues across Path 15 and then undo the congestion-relieving flow through an offsetting flow in the opposite direction on the same path using NCPA grandfathered transmission rights but never leaving the ISO. (Exh. CA-145, at 390 and 1353)

Q. Did Enron and NCPA engage in Cong Catcher?

Yes. An Enron email from April 2001 indicates that this strategy has been used by Enron and NCPA in the past. The profits from these past deals were split between the two parties, likely under their "Transmission Management Contract." (Exh. No. CA-86). The Enron email also announces to Enron's traders that the "NCPABR IS BACK", continuing on with a description that indicates that the buy-resell is a Death Star type loop. A review of the Enron trade book data (Exh. No. CA-74) indicates that Enron entered into 21 of these buy-resell transactions in the following month. For its participation in these transactions, NCPA earned a fee of between $25/MWh and $60/MWh. Prior to the Enron transmission contract, NCPA had a similar contract with Williams that may have been used to engage in Cong Catcher-type strategies. (Exh. No. CA-145 at 388).

Q. Does MID also use similar Death Star type strategies?

A. Yes. Documents produced by MID included an undated presentation that explicitly lays out a Death Star type strategy. The discussion focuses on how MID can benefit from congestion on the ISO's system and reads as follows:

> *MID is in a unique position to create revenue from congestion. Before congestion can occur, the ISO deems all Existing Rights holders of transmission to be fully loaded. If you schedule the opposite direction of congestion and it is not fully relieved, you will be paid the Usage fee of the*

[51] The document title shows that this document was created much earlier than the memo's dateline.

congestion pathway. If you schedule opposite congestion and relieve the congestion on the pathway, you receive no Usage fee. We have scheduled two ways against a congested pathway, a straight sale, and a sale and a purchase at the same point. The example on the next page will cover this example. (Exh. No. CA-88 at 4)

Q. How do you know that the strategy described in this MID document is a Death Star type game?

A. The document also shows a diagram that provides clear evidence of the circular nature of this transaction. The transaction begins with MID selling power to its Scheduling Coordinator who then exports the power from the ISO over the ISO's transmission system.[52] The exported power is sold to Portland General Electric (a subsidiary of Enron), which then sells the power back to MID. To complete the loop, MID uses its transmission capacity on the California Oregon Transmission Project ("COTP") to schedule the power back down to MID where it originated.

Q. How would MID make money from implementing the transaction described in this document?

A. Using this strategy, MID recognizes that it will be paid by the ISO for relieving congestion by transmitting power across ISO transmission capacity in the direction opposite to congestion. This game is referred to as "scheduled two ways against a congested path." Unlike Enron's Death Star, in this variant, MID actually schedules power in the opposite direction on the same transmission path (*i.e.* this is an out-and-back, "circular" transaction). However, this can only be done because MID controls transmission capacity (known as Existing Transmission Contracts or "ETCs") on an ISO export/import path, but the ISO does not have DA or HA schedules for MID's capacity because ETC capacity is not subject to the scheduling protocols of the ISO. Therefore, while the ISO sees MID scheduling power in one direction along the path, it does not see (until just before RT) that the same amount of power is being scheduled in the opposite direction on MID's ETC capacity. Thus, the ISO is led to believe that congestion on ISO transmission has been reduced, when in reality, the relief is fictitious because no power actually flows.

Q. Do you know if MID engaged in Death Star type transactions?

A. Yes, MID was identified in Tables E-1 and E-2 above as engaging in Death Star games in only five instances for 100 MWh. PacifiCorp's PA02-2

[52] The fact that MID sold through PG&E back to itself in the first stages of this overall transaction raises questions as to whether MID was intending to conceal the circular nature of the trade.

filing indicates that the company had been engaging in buy/sell agreements, similar to those portrayed in its Death Star Memo, with "MID quite a bit."(Exh. No. CA-332 at 10) By May 2000, Enron traders had become aware that MID was engaging in Death Star transactions with PacifiCorp. (Exh. No. CA-145 at 1320-1) However, as noted above, my Death Star analysis is conservative, and is unable to detect certain transactions because they are well camouflaged. These transactions evade my screens, such as MID Death Stars, if they: (1) use ETC capacity; (2) use different scheduling coordinators for the import and export legs; or (3) create a loop within the ISO. Thus the results of my analyses are conservative.

Q. Do you believe the number of Death Star transactions *not* captured in your analysis is large?

A. Yes. For example, while my analysis identified only five MID Death Star deals, documents produced by MID show that their use of this strategy occurred nearly every day. Exh. No. CA-99 is a partial set of MID Daily Operations Orders from March 22, 2000 through March 2, 2001. On July 22, 2000 MID's report identifies the following transaction:

> *MID1 ZP26 LOOP – 33 MW HE 1-25 [792 MWH]. This is system energy scheduled to MID1 at NP15. MID1 is then moving the energy from NP15 to ZP26 using CISO transmission where they will schedule the energy back to MID at ZP26 to take advantage of congestion. We are then using our MTS to bring this energy into our system. (No tag required.) (Exh. No. CA-99 at 25)*

In this deal, MID moves power from NP15 to ZP26, using ISO transmission. At this point the energy is scheduled back to the MID system, which is in NP15, presumably on its ETC capacity. The rationale for this loop is to "take advantage of congestion." Since this transaction uses ETCs and is internal to the ISO, it evades my screens.

The first incident of this type transaction by MID that I can find occurs on June 13, 2000, although logs for the previous month were not provided. From this point forward, MID appears to use this strategy on a near-daily basis for as much as 2,400 MWh/day through the end of February 2001. MID may continue to use this strategy after this date, but these operations logs were not produced on discovery.

In addition to MID, we know there are others using Death Star that would evade the screens, such as the NCPA Cong Catcher game described above. Trader transcripts for buy-resell trades between Aquila and PacifiCorp

identify other potential Death Star transactions that would evade my screens. These tapes identified what appear to be Death Star transactions that involved either Turlock Irrigation District or Redding, each of which hold ETC capacity. (Exh. Nos. 329 and 330).

Q. What evidence do you have that Glendale engaged in Death Star type strategies?

A. The City of Glendale employs a similar strategy to conduct Death Star-type transactions in cooperation with Coral Power. Glendale's use of this game, which it refers to as "Congestion," is described in a document that discusses the city's trading strategies:

> *Congestion: Congestion revenues can be earned by the City at tie-points or on intra-state transmission lines. At tie-points in Wheels that utilize Glendale transmission flow with congestions, but go against congestion on ISO transmission. Since Glendale can take this power back into their system the power is priced at zero, and losses, Grid Management Charge, Take Out Charge, and UFE/Neutrality are the only items that need to be factored into your congestion price offer. An example of a tie-point congestion play might be to come into the ISO on ISO Transmission at Sylmar and into Glendale's system. (Exh. No. CA-168 at 1-2)*

Q. If Glendale was playing Death Star type games, why do they not appear in the results of your analysis?

A. There are two possible reasons. First, as of 8/1/00 Glendale had a comprehensive "marketing agreement" with Coral that allowed Coral to submit schedules with Glendale generation. (Exh. No. CA-118). Coral is among the most prevalent users of Death Star transactions. Coral also tops the list of individual entities with potential Death Star trades with the highest and second highest volumes of such trades during the Summer and Fall/Winter time periods. Second, Glendale is one of the California municipal utilities that would evade the screen used in my analysis because it holds transmission capacity outside the ISO's control.

Q. What evidence do you have suggesting that Mirant was engaging in Death Star games?

A. Mirant (at the time known as Southern Company Energy Marketing, or "SCEM") has similarly been involved in scheduling Death Star games. One of its traders describes these trades as "loop-t-looping" in a June 2000 conversation with a Public Service of Colorado ("PSCo") employee. This conversation, which was not disclosed in Mirant's own Docket No. PA02-2

filings, was provided as an attachment to the PA02-2 filing of Xcel Energy, the parent of PSCo. The conversation went as follows:

> *"PSCo: Yep, that 26 is north to south right now? SCEM: Yeh, so we are basically scheduling it on PV but scheduling on to load on NP. Laugh . . . it has been working pretty well. PSCo: What do you mean you are scheduling to PV . . .you are taking energy out of the north and wheeling it south. SCEM: That's right . . . and scheduling it to load at NP . . . laugh . . .I mean its just kind of loop-t-looping but it's making money . . . laugh." (Exh. No. CA-204, at 21).*

I would note that the term "Loop-t-looping" is consistent with the nomenclature used by Mirant in the Death Star interchange IDs discussed earlier, "SCEM-Loopy."

Q. What evidence do you have of the use of Death Star games by other entities?

A. In addition to the evidence presented for MID, Glendale, Coral, and Mirant, documents produced in the course of this and other proceedings have identified these other entities participating in Death Star-like games:

- **Coral and Powerex.** The notes of Mary Hain of Enron implicate two other entities involved in Death Star strategies on their own: Coral (discussed above in conjunction with Glendale) and Powerex. (Exh. No. CA-93 at 225-6) In addition, Coral trader tapes document a Death Star transaction used by Coral. (Exh. No. CA-301)

- **Duke Energy.** In December of 2000, a Duke trader circulated to a large number of Duke traders a document entitled the Adjustment Bid Strategies Overview, which was informally called the "cheat sheet." The strategy deals with developing adjustment bids that can be used to complete an export-import "circuit." One of the legs of this circuit must be designed to provide counterflow against a congested path. (The cheat sheet does not provide detail on how the export-import circuit was closed, but this closure likely takes place outside of the view of the ISO). (Exh. No. CA-164)

- **LADWP.** In February 2000, LADWP was considering joining the ISO. In an internal email, a LADWP employee is weighing the costs and benefits of ISO membership. A critical "cost" that is considered is the loss of revenues for the "phantom congestion" that LADWP

was able to garner because it is not a member of the ISO. While the e-mail does not specifically identify the source of these phantom congestion revenues, it is likely that at least a portion of them may relate to Death Star-like trades, including those in which LADWP traded with Enron. (Exh. No. CA-80) This is consistent with the fact that LADWP transmission plays an important role in strategies such as the Forney Perpetual Loop, which receives congestion payments, even though no power flows. (Exh. No. CA-145 at 624)

- **Sempra.** I have already noted the ISO's emails regarding Sempra circular transaction in the introduction to my Death Star discussion. (Exh. No. CA-132) In a later string of emails responding to the same transaction, one ISO employee referred to it as a "phantom wheel." Another ISO employee notes that this game can be played because neighboring control areas do not base transmission (wheeling) charges on the zonal energy price differentiation. This transaction is also discussed by ISO employees as "far from a one-time event," because Sempra uses phantom wheel and other games to earn congestion revenues. (Exh. No. CA-129 at 1)

D. IMPLEMENTING CUT SCHEDULE GAMES

Q. How does a trader engage in a "cut schedule" congestion strategy?

A. Cut schedule games include various strategies such as "Non-Firm Export" and "Scheduling Energy to Collect Congestion II" from the Enron memos. When the ISO experiences congestion in the DA and HA markets, it will pay suppliers to provide a counterflow, which will relieve, in whole or in part, that congestion. The users of this strategy earn congestion revenues by scheduling a counterflow in the DA and HA markets in order to be paid for relieving congestion. In this strategy, the schedule providing counterflow is intentionally eliminated after the congestion payment is awarded and cannot be rescinded by the ISO's accounting system. Despite the fact that the schedule was cut, the Scheduling Coordinator keeps the payment received for the originally-scheduled congestion relief.

Q. What does a Scheduling Coordinator do to cut its schedule?

A. There are two basic ways to do this: (1) request that the ISO cancel a schedule; or (2) intentionally submit a schedule in a way that ensures the ISO will cut it. Several specific methods of cut schedules games identified in discovery fall into these two basic categories.

There are three hours between the close of the forward schedules (*i.e.*, DA and HA) and the issuance of RT dispatch instructions by the ISO. During that time, a Scheduling Coordinator could request that the ISO cancel a schedule and the ISO would usually comply. Often such cut schedule requests involved non-firm transactions. Allowing market participants to cut schedules on short notice, particularly when they relate to non-firm transactions, is a common practice throughout the West. In some instances, schedulers are simply unable to fulfill their final schedules due to a forced outage of a plant or transmission line. When this occurs after the markets close but before RT dispatch, it is necessary and appropriate to notify the ISO and request a cut. However, under the cut schedules congestion game traders misuse this legitimate option by submitting schedules that are *intended* to be cut and that the traders know they cannot or will not deliver. Enron's December 6, 2000 memo refers to such games as its "non-firm export" strategy.

A second method of gaming schedule cuts is to submit schedules that are known or expected to be cut by the ISO due to transmission limitations or transmission outages. The ISO has the authority to cut schedules for reliability reasons, and frequently imposes such cuts on its own. One very obvious example of such ISO-initiated cuts is due to outages of transmission lines. Any transactions scheduled over such a forced-out transmission line will need to be cut unless they can be accommodated in some other fashion. An example of this type of cut schedule game is Enron's "wheel-out" strategy.

A third method of gaming schedule cuts involves intentionally failing to complete the paperwork necessary to assure the ISO that a submitted schedule is available for RT dispatch. Without the required paperwork, the ISO will simply cancel a schedule itself. In this case, the specific paperwork required to complete an export trade is known as a "tag." Among other things, tags specify the source (location of the generation unit) and sink (location of the load) for all transactions. In order to perform its plant dispatching function efficiently, the ISO requires that all export or import transactions have tags submitted by the SC before the time of dispatch. If they do not, the ISO may cut the schedule.

Finally, a strategy that essentially also amounts to a "cut schedule" game is based on submitting bids to create offsetting powerflows in RT. For example, a Scheduling Coordinator would (1) submit a DA or HA counterflow export over a constrained interface to earn congestion payment; and (2) submit a supplemental energy bid import in the opposite direction. As soon as the ISO selects the supplemental energy (RT) bid for

the RT market, the Scheduling Coordinator informs the ISO that the two offsetting schedules net to zero and that no power needs to be delivered under *either* schedule. In other words, with this method the counterflow schedule effectively is "cut" by creating an exactly off-setting RT transaction.

Q. What economic harm is caused by market participants playing cut schedule games?

A. In addition to collecting congestion relief payments without providing any actual relief, this practice also has the effect of shifting power supplies from the DA and HA markets into RT. For example, when a supplier schedules a DA export, the market believes the exported power will be unavailable within the ISO. This raises the DA price. When the schedule is cancelled after the DA and HA markets close, the generation dedicated to the original DA export suddenly becomes available, but only to the RT or OOM market.

The economic effect is nearly identical to that of a Ricochet transaction. The only difference is that a Ricochet trade has a valid schedule that exports power out of the ISO control area (at least on paper), only to return the same power in RT or as an OOM import. In contrast, cut export schedules shift the power from DA and HA into RT without the fictitious round trip to a sink outside the ISO's control area.

Q. Could Scheduling Coordinators that play cut schedule games be pursuing legitimate economic interests?

A. No. There is no economic efficiency justification for pretending to sell a particular product in a market, getting paid for that product, and then willfully taking steps to ensure that the product is not delivered. Indeed, most markets and contracts, including other electric auction markets, are set up to automatically withdraw payment or create an equal and offsetting (if not more than offsetting) charge for non-delivery of such promised services. The CAISO's software, and its overall market design, did not allow for taking back ill-gotten congestion payments during the 2000-2001 time frame. Furthermore, imperfect interregional coordination contributed to the ability to execute some of these strategies. However, the fact that the ISO's settlement software could not prevent sellers from benefiting from cut schedules games, nor could existing regional coordination practices, does not excuse buyers from engaging in such intentional non-delivery of a product, while retaining payment, nor does it make such practices pro-competitive.

Q. Are there any reliability concerns associated with cut schedule games?

A. Yes. The reliability consequences of these strategies are straightforward. Canceling beneficial counterflows close to RT causes the ISO's operators to have to scramble to relieve any resulting RT congestion just as ISO operators would have to adjust to the forced outage of a scheduled generating unit. Especially in the chaotic California markets, placing greater congestion management burdens on RT system operators could not reasonably have done anything other than increase the chance of reliability problems. An email obtained from the CAISO in discovery, written in August, 2000 summarizes the ISO's view of the reliability implications of cutting counterflow schedules:

> *If these counter schedules are cut without cutting the corresponding in bound schedules after the close of the HA, it causes problems. Assuming the tie was fully scheduled in the in bound direction, cutting an out bound one causes the in bound directions to be over scheduled. That is a reliability problem. (Exh. No. CA-127 at 1)*

Another ISO email also mentions the possibility that cut schedules might lead to the overloading the California-Oregon Intertie ("COI") due to the absence of a previously-expected sink (Exh. No. CA-131).

E. EVIDENCE REGARDING MARKET PARTICIPANTS' USE OF CUT EXPORT SCHEDULE

Q. Is there any specific evidence that market participants were actually engaging in cut schedule games?

A. Yes. Evidence about cut schedule games comes from a number of sources. First, as discussed above, ISO-internal documents produced in discovery allude to the use of cut schedule games by various Scheduling Coordinators. Second, the ISO has conducted analyses to identify cut counterflow transactions that appear to be part of intentional games by Scheduling Coordinators. Finally, I provide additional evidence obtained for individual market participants, showing their knowledge and foresight with which cut schedule games were played.

Q. What is the additional evidence from the ISO about the prevalence of cut schedule games?

A. Documents indicate that the ISO was aware of this practice as early as June 2000. An email sent by an ISO operator on June 29, 2000 states that the ISO continues "to experience problems with EPMI and other S/Cs who neglect to call us with a source or sink when putting in H/A changes."

(Exh. No. CA-115) As discussed above, if a supplier cannot provide a source or sink as RT dispatch approaches, the ISO will generally eliminate the schedule.

The ISO subsequently investigated gaming through the cancellation of transactions providing non-firm counterflows. This investigation led the ISO to issue the following market notice on July 21, 2000:

> *Several market participants have been engaged in a practice of scheduling large amounts of non-firm counter flows on congested branch groups in order to earn hour-ahead congestion revenues and then not providing those counter flows in real time. This occurred during a Stage 1 emergency on 7-20-00. This practice creates a significant reliability problem for the ISO and is to the detriment of market efficiency.*
>
> *This notice is intended to inform Market Participants that the ISO Department of Analysis considers this a potentially serious "gaming" practice as defined in the ISO Tariff MMIP 2.1.3. The ISO DMA will be investigating any Market Participant found to be engaging in this activity and will take appropriate corrective actions. (Exh. No. CA-113)*

Q. Did the ISO undertake any analyses to identify how widespread such cut schedule games might have been?

A. Yes. The ISO presented such analyses in its October 2002 ISO Enron Strategy Report indicating that cut schedules games, such as "wheel out" or "non-firm exports," likely were persistently used by some Scheduling Coordinator throughout the 2000-2001 time period.[53] I have independently verified the ISO's analysis, and have used the workpapers to analyze individual Scheduling Coordinators' potential cut schedule trades for the January 2000 through June 2001 time period.

Q. What are the results of this analysis?

A. Tables F-1 through F-3 summarize the results of this analysis. All transactions identified in these tables represent DA or HA counterflow schedules that earned congestion payments but were cut prior to RT operations. (I have also removed several transactions where the ISO

[53] October 2002 ISO Enron Strategies Report (Exh. No. CA-109 at. 7 (discussion of "non-firm export"), at. 24-28 (analysis of "wheel out"), and at. 30-34 (broadly analyzing "cut counter flows").

operator log entry implies that the schedule cut may not have been initiated by the Scheduling Coordinator.)

Table F-1 summarizes the occurrences and magnitude of these cut counterflow schedules for the identified Scheduling Coordinators for the May 2000 through June 2001 period. Table F-2 summarizes the same data for each of the four subperiods. Table F-3 lists all of the identified cut schedule transactions for which an ISO operator log entry was available. These ISO operator log entries are fully consistent and strongly indicative of cut schedules games by these market participants. As shown, many of these transactions were cut because of missing sources or sinks—which is the signature of one of the cut schedule methods discussed above.

The tables shows that scheduling counterflow transactions, receiving counterflow payments, and then cutting the schedule appears to have been a pervasive practice throughout the May 2000 through June 2001 period, but was most common in the Fall/Winter of 2000. Table F-1 shows that from May 2000 through June 2001 a total of 357 cut schedules hours accounted for the cancellation of transactions involving more than 22,000 MWh. Table F-2 shows the following results for the individual sub-periods:

- **Spring 2000.** Compared to the rest of 2000, there were fewer cut schedules following counterflow payments. However, three parties stand out as having notably more cut schedules than anyone else. These are AEP, SDG&E and Sempra. Together these parties were responsible for more than 80% of the cut MWh.

- **Summer 2000.** The total number of cut MWh was far greater during this period than during any of the other periods considered. In total, schedules cut following counterflow payments accounted for more than 12,000 MWh. Cut schedules happened most often for Powerex, Sempra and Enron, who together were responsible for 50% of the cut schedules. Although Dynegy did not have as many cut schedules, it was responsible for far more cut MWh than anyone else, totaling more than 4,500 MW.

- **Fall/Winter.** From Summer to Fall/Winter, the rate at which schedules were cut following counterflow payment appears to have remained fairly constant. During the Fall/Winter, there were in total 129 hours of cut schedules involving more than 4,000 MW of transactions. Four parties show notably more cut schedules than others during this period. These are SDG&E, Sempra, Coral and

Enron. Together, these parties were responsible for almost 75% of cut schedules.

- **The CERS Period.** While the overall frequency of cut counterflow schedules fell for the January 18 through June 19, 2001 period, the total magnitude remained high. Seventy-two hours of schedules were cut by market participants after congestion payments were awarded amounting to more than 5,000 MWh of transactions. Morgan Stanley accounted for 44 cut schedules, representing more than 4,000 MWh during this period, far in excess of other parties.

Q. Is there additional evidence on which Scheduling Coordinators were involved in cut schedule games?

A. Yes. Evidence produced in discovery provided the following additional evidence on cut schedules games by individual Scheduling Coordinators:

- **Coral Energy.** Notes by Mary Hain of Enron, appear to indicate Enron's belief that Coral Energy was pursuing cut schedule strategies. (Exh. No. CA-93 at 227-8) This claim is also consistent with my analysis showing that Coral had 35 cut counterflow schedules during the time period analyzed. As Table F-3 shows, at least several of Coral's counterflow schedules were cut due to missing sink or source information.

- **Powerex.** Mary Hain of Enron also implicates Powerex for engaging in cut schedules strategies. (Exh. No. CA-93 at 227-8) This claim is consistent with my analysis indicating that Powerex had 41 incidents of cut counterflow schedules during the May 2000 through June 2001 period.

- **Duke Energy.** An investigation of Duke by the ISO focused on a May 27, 2000 event when the ISO had to cut Duke's non-firm schedules due to a transmission outage. The ISO, after investigating the event, concluded that Duke was aware of this transmission outage when it submitted its schedule, and thus had purposefully scheduled these transactions to earn congestion revenues with the advance knowledge that the transactions would be cut by the ISO in RT. (Exh. No. CA-114) Table F-1 shows that Duke was involved in a total of 19 potential cut schedules games.

- **Idaho Power Company ("IPC").** A review of the ISO's Non-Compliance Report on April 30, 2001 indicates that IPC was

involved with scheduling non-firm energy and then cutting it on a RT basis. In scheduling its energy IPC allegedly misled the ISO to believe that its scheduled energy actually was firm. The Non-Compliance Report states that this has been an ongoing problem with IPC, and that the ISO should consider revoking IPC's Scheduling Coordinator rights. (Exh. No. CA-111) This comment is also consistent with the results of my analysis, showing that IPC had 19 cut counterflow schedules during the May 2000 through June 2001 period.

- **Sempra.** A November 9, 2000 letter from the ISO to Sempra documents three incidents of cut schedules on November 6, 2000, each of which involved "reduction or complete non-performance of awarded energy schedules, which were awarded to relieve congestion."[54] The letter stated that Sempra must "cease and desist this destructive market activity...This type of activity constitutes gaming of the market." (Exh. No. CA-130). ISO internal emails also indicate that this is just one of Sempra's games for earning congestion revenues. (Exh. No. CA-129) and that "it boils down to scheduling phony counter flow, and then bidding sup energy in the opposite direction with the net result that they don't deliver anything" (Exh. No. CA-300). Again, the additional evidence is consistent with the results of my analysis summarized in Table F-1, documenting 59 incidents of cut schedules for which Sempra earned congestion revenues during the May 2000 through June 2001 period. This is more than any other entity during this period.

- **Williams.** Hints of Williams' use of this strategy is implied in a long list of trading strategies written sometime before February 3, 2000 obtained on discovery from Williams (Exh. No. CA-22 at 1). The fourth strategy on this list reads "[s]chedule import/export without a source or sink in advance because market appears to be in the money." Although this statement does not conclusively prove that Williams pursued cut schedules games, the described strategy suggests a perfect setup for such games because, without finding a source or sink and submitting a tag for the transaction, the ISO would generally cut the schedule in RT.

Q. Do all "cut schedule" type involve import or export games?

A. No. In a May 2000 email, Dynegy shows how traders were looking for ways to game the markets, including the use of cut schedule games internal

[54] The copy of this letter received in discovery was unsigned so I cannot verify the letter was sent.

to the ISO. The email indicates that the strategy being tested was to schedule both generation and fake load (*i.e.,* a fat boy) in the DA market in a way that Dynegy would receive a payment of $42,000 for relieving DA congestion between NP15 and SP15. The trader would then zero out his generation after receiving this payment (*i.e.*, not produce a source for the tag). Similar to a cut schedule, the trader intended to receive a payment for relieving DA congestion with actually providing any relief.

Interestingly, the trader failed to consider that canceling the schedule in the hour-ahead market may subject Dynegy to pay an HA congestion charge. After using this strategy for a week, Dynegy realized that the strategy was losing money, and the trader using that strategy was instructed to stop. I note that internal cut schedule games such as this would not be detected by my screens. Interestingly, during the same period when Dynegy was testing the system, Summer 2000, they were the most prevalent user of cut schedule games.

F. "LOAD SHIFT" CONGESTION GAMES

Q. What are "Load Shift" games?

A. The ISO's procedures require that schedulers submit equal amounts of generation and load, and that they identify the zone in which the load resides. Under this strategy, a seller simply offers a DA or HA schedule that contains intentionally misstated load locations. The location of loads is a key variable in the ISO's computation of transmission congestion and therefore zonal price differences. In some cases, the Scheduling Coordinator knows the system well enough to schedule false load locations so as to create or increase congestion and zonal prices.

The December 6, 2000 Enron Memos describe a congestion game called Load Shift, which involves creating congestion by shifting loads, then profiting from that congestion. In a Load Shift game, an entity overschedules its DA or HA load in one zone in order to help create congestion into that zone. This congestion causes the ISO to make payments to the owners of Firm Transmission Rights ("FTRs") in an amount equal to the costs of congestion across the constrained interface. In essence, a Scheduling Coordinator schedules load in a way to create congestion so it can profit from that congestion.

Q. What incentive does a Scheduling Coordinator have to engage in this game?

A. The incentive to execute Load Shift games is derived from the Scheduling Coordinator's ownership of FTRs. An FTR is an entitlement to one MW's worth of the congestion revenues across one interface. The more congested a line, the higher the per-MW zonal price difference, the more revenues an FTR holder earns from all buyers in the high-priced zone. The ISO awarded FTRs in an auction, and many Scheduling Coordinators purchased them.

A Scheduling Coordinator who owns a large share of FTRs for one transmission interface increases its profits greatly as congestion increases across that same interface. If false reporting of load location causes or increases congestion, and the Scheduling Coordinator is not otherwise punished for false load location, this strategy can be profitable.

Q. Are Load Shift strategies harmful from an economic or reliability perspective?

A. The economic harm from this strategy is clear. The entity that owns the FTRs is paid for congestion that does not really exist. Further, as noted in the December 2000 Enron memos, this strategy results in higher costs for all those using the constrained paths on which load shift strategies create congestion. The strategy also is likely to create additional operational challenges for the ISO, since the misleading load schedules create fictitious congestion that complicates the ISO's congestion management process.

Q. Is there likely justification for such Load Shift strategies that is consistent with economic efficiency?

A. No. The strategy relies on the intentional submission of false load information to the ISO. I see no justification for doing so. It only imposes additional costs on consumers due to the creation of fictitious congestion that contributes to market dysfunction. To the extent that Load Shift strategies have been combined with other games, such as Fat Boy, the impacts will only be magnified.

Q. Is there any evidence that Load Shift strategies were pursued by market participants?

A. Yes. The December 6, 2000 Enron memo clearly describes Enron's use of Load Shift strategies. An internal Enron estimate suggests that Load Shift games also earned Enron more than $30 million in revenues during Fiscal Year 2000 alone. (Exh. No. CA-93 at 176-9).[55] The overall damage of load shift games, however, will exceed any congestion revenues earned by Enron because, as the Enron memo indicates, this strategy results in higher

[55] An analysis included in the ISO's Exh. No. CA-109 suggests that the benefits to Enron might have been much smaller than that. However, these results were strongly qualified by the ISO.

costs for all those using the constrained paths on which Enron is creating congestion.

Q. Have other Scheduling Coordinators used load shift games?

A. It appears that Enron may not have been the only Scheduling Coordinator using this strategy. An undated transcript attached to Xcel Energy's filing in Docket No. PA02-02, includes a discussion of traders referring to load shift games by Duke and Williams:

> *"G:. . . have you seen this stuff they're trying to do in California now? . . . the way we under schedule load . . .the thing is you create congestion . . . Williams and Duke do that all the time. They over . . .schedule a . . . load at SP. So, they create tons of congestion because they have all that generation in ZP26 . . . you got 500 Megawatts of FTRs . . . And you create that by . . .over scheduling 200 Megawatts . . . even though you get less from your energy . . . you collect the money on 500 Megawatts on FTRs and you're only losing it on 200 Megawatts . . . Every time you win. Every xxx time you win, so we're gonna do that every day." (Exh. No. CA-204 at 42-3)*

I have been unable to verify that the allegations in this transcript are correct. However, both Williams and Duke owned FTRs on Path 26 during the period from February 1, 2000 – March 31, 2001, which would be the likely prerequisite to make such load shift games profitable. In addition, the above claim of congestion games by Duke also is consistent with a Duke adjustment-bid game documented by the ISO (Exh. No. CA-126) under which Duke was able to manipulate DA congestion during December 18-20, 2000. According to the ISO's analysis, this particular gaming instance drove up DA market prices in northern California (NP15) by more than $200/MWh over what prices would have been without Duke's actions. While Duke earned close to $7 million on these three days, the harm to consumers in northern California was much larger because all NP15 Sellers received the inflated market-clearing price from all buyers in this zone – not just Duke and its customers.

The transcripts provided in Xcel's PA-02 filing also indicate that Xcel (through its subsidiary Public Service Colorado (PSCo) jointly pursued load shift-type congestion games with Mirant (*i.e.*, Southern Company Energy Marketing). A transcribed conversation between Mirant on July 18, 2000 explains a congestion game in which Mirant moves power received from PSCo at "Four Courners" to "over schedule load [in] SP and …NP for

a congestion play." Acknowledging that "it's going to get kinda messy starting playing that congestion," Mirant and PSCo agreed that it would "probably be simplest to do some kind of split upside." (Exh. No. CA-204 at 28-9)

Coral and Glendale also implemented load shift transactions as shown in a document exploring a number of trading strategies that were apparently implemented under the joint working agreement between Coral and Glendale (Exh. CA-No. 168). This document spells out the following load shift-type congestion game: load shift-type.

> *Inside the ISO, you can take Glendale supplied power via an SC to SC transfer in South Path, move it to North Path (against congestion) and park it on a Coral Load ID. Glendale would earn the congestion payment and any gain (or loss) on the power from being paid the Decremental Price in NP15. (Exh. No. CA-168 at 2)*

Powerex also appears to have pursued Load Shift games in connection with other strategies related to the intentional overscheduling or underscheduling of load. In one document obtained in discovery, Powerex discusses the benefits obtained from an agreement with PG&E Energy Services ("PGES")[56] that allowed Powerex to over-schedule and under-schedule load in different load zones to "collect P15 congestion by adjusting the load in NP15 down." (Exh. No. CA-46 at 2)

Finally, the CA parties have obtained evidence that at least some of Enron's load shift games were implemented in cooperation with some of California public utilities. For example, a June 6, 2000 email from Enron with the subject header "NCPA BR IS BACK" describes a "sweet strategy" under which Enron shifts "load from SP15 to ZP26". The strategy involves a "ZP26/NP15 Buy-Resale on a Real Time basis" with the NCPA to "shift" power back across "PATH15 and not be subject to Congestion as NCPA has Grandfather Rights across the path" (Exh. No. CA-145 at 1353). Enron's strategy also included scheduling power such that the amount scheduled conceals Enron's use of NCPA's capacity. The RT shift of power over NCPA's capacity also means that this congestion game involves a circular, but ISO-internal trade utilizing transmission capacity that the ISO does not control due to NCPA's non-participation in the ISO

[56] PGES was an affiliated but independent company from PG&E until it was acquired by Enron in June 2000, at which point it changed its name to Enron Energy Marketing Corp.

and its associated existing contractual transmission rights. This trading strategy described above, was also referred to as "NCPA Cong Catcher."

X. ANCILLARY SERVICES STRATEGIES

A. THE STRATEGIES AND THEIR IMPACTS

Q. How were Scheduling Coordinators gaming the AS markets?

A. The AS markets were the subject of gaming in which Scheduling Coordinators were selling AS to the ISO that were not truly available for use by the ISO. I refer to these strategies as "overselling of AS." The overselling strategies that market participants are able to utilize depend in part on the location of the resources producing each specific AS. This is because the ISO's monitoring of resources within the ISO system prevents the pursuit of certain AS games for sales from ISO-internal generation resources. Thus, my discussion of AS games focuses on two strategies: (1) overselling of AS from imports; and (2) overselling of AS from ISO-internal resources.

Q. What were the impacts of these ancillary service strategies?

A. As discussed within this section, AS overselling likely caused the ISO to purchase significantly greater amounts of AS than it might otherwise have purchased, pushing up AS costs. This is likely a causal factor in the large increases in the total costs of AS purchases by the ISO in 2000. In Summer 2000, total AS costs rose six-fold above 1999 levels ($843mm vs. $139mm). For June 2000 alone, AS expenditures were more than ten times the amount for the previous June ($436mm vs. $43.3mm).[57] In addition, as I explain further below, these AS games undermine reliable ISO operations and create a significant threat to overall system reliability.

B. OVERSELLING OF ANCILLARY SERVICES FROM IMPORTS AND ITS CONSEQUENCES

Q. What practices were suppliers using to "oversell" AS from imported resources?

A. AS games from imports often involved the sale of AS into DA markets and subsequent repurchase of those same AS in the HA market. The December 6, 2000 Enron memos describe this game as "Get Shorty." Under this strategy, Enron would sell "short" AS (*i.e.,* sell AS Enron did not have) in the DA market by falsely designating external resources, even though it did not physically have available AS capacity from the designated resources.

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[57] Market Analysis Report, Anjali Sheffrin, October 13, 2000.

These AS offers would later be bought back in the HA market, effectively closing out Enron's "short" position so that no AS would have to be delivered and the ISO did not realize that Enron never had available the AS capacity that it offered and that the ISO purchased on a DA basis.

Enron referred to this as a "paper trade" because it is AS that it does not physically have. Since the position is closed out without any delivery, the ISO never knows that the resources to back the bid were unavailable.

Q. Can resources within the ISO use the Get Shorty strategy?

A. No. Get Shorty works only for imported resources. As discussed in the Enron memos, this strategy required Enron to provide the ISO with false information and violate the ISO's requirement that any AS sales need to be backed up with physical resources. Because internal sellers of AS must identify the specific resource providing the services and the ISO is able to monitor the status and availability of internal generating units, the ISO software is able to identify AS schedules that are not feasible. However, the ISO is not able to monitor generation resources outside its control area and, as a result, needs to rely on a seller's representation that they have physically available the AS capacity sold to the ISO.

Q. What harm is imposed by the use of Get Shorty?

A. The use of Get Shorty-type strategies imposes economic and reliability consequences on users of the grid. WSCC rules require the ISO to maintain minimum amounts of AS under contract, depending on loads and other factors. If AS sold in DA markets are bought back in the HA market, the ISO must scramble to locate required levels of AS it believed it had already purchased. In fact, as discussed below, there have been instances when awarded AS from imports simply were not available in RT. If the ISO cannot rely on DA schedules for AS, it must overbuy AS in the DA market as an insurance margin or scramble to fill the gap with HA purchases. All this increases total market cost, and creates the risk that the ISO will be caught short of required AS capacity in RT.

Q. Could Get Shorty strategies be considered pro-competitive?

A. In general, the ability to arbitrage between DA and HA markets should be considered economically efficient if these markets are workably competitive and reliable system operations allowed the purchase of all or most AS requirement on an HA basis. However, operating reserves are not ordinary commodities. Unlike ordinary commodities, failure to deliver on a short sale could lead to market wide reliability problems, not just one isolated financial loss. These concerns are significant enough that the ISO

is proposing a tariff amendment that will ban such AS sell-repurchase strategies.[58]

In addition, Get Shorty strategies are not mere arbitrage strategies. First, they may involve selling non-existent AS that the supplier may not be able to provide when called upon in RT. They may also involve selling AS that the supplier never intends to deliver. Both of these types of strategies create the harmful economic and reliability effects described above.

C. EVIDENCE OF OVERSELLING OF ANCILLARY SERVICES FROM IMPORTS

Q. What evidence do you have that importers were employing Get Shorty-type strategies of overselling AS from imports?

A. Documents obtained in discovery provide evidence that various other market participants appear to have used similar overselling AS strategies, as well as additional evidence on Enron's use of the Get Short strategy. For example, as I discuss below, during many episodes in June 2000, Enron scheduled and mistakenly failed to repurchase in the HA market the non-existing AS it sold to the ISO on a DA basis. These mistakes led the ISO to observe that Enron was selling AS that it could not deliver when called upon in RT.

However, we do not know how many times Enron sold undeliverable amounts of imported AS because: (1) many times it successfully repurchased AS in the HA market such that any remaining amounts could be delivered when called upon by the ISO; and (2) at many other times the ISO did not call on Enron's AS capacity. In fact, the main purpose of AS capacity is to provide reserve capacity that remains unloaded (*i.e.*, is not called upon by the ISO) to ensure system reliability.

The ISO's own analysis of AS overselling obtained in discovery shows that during the critical months of June through September 2000, there were a total of 30 events (involving more than 1400 MW) during which Enron was unable to deliver energy from its sold (*i.e.*, not repurchased) imported AS capacity when called upon by the ISO. (Exh. No. CA-109 at 24). Only when these failures to deliver energy from paid-for AS capacity occurred could the ISO see that the AS capacity it bought from Enron did not exist. And only in these instances, was the ISO able withdraw the payments made for non-existent AS. (See "non compliance adjustments", Exh. No. CA-109 at 24).

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[58] ISO Tariff Proposed Amendment No. 47.

We have also obtained in discovery Enron's own internal discussions of instances when Enron traders failed to make the intended repurchases. In June 2000, the traders working under Enron Vice President Tim Belden failed on certain occasions to repurchase non-existent AS sales in the DA market. Mr. Belden admonished his traders to develop and document a procedure to assure that the intended repurchases actually happen. (Exh. No. CA -145 at 1174) A few weeks later, when the failures to repurchase continued and threatened to expose Enron's practice of selling non-existent AS capacity, an evidently angry Belden ordered his traders to stop using the strategy until they developed the protocol he had requested to assure repurchase. (Exh. No. CA-145 at 1175)

ISO documents concerning this June 2000 flurry of false AS sales by Enron also show that Enron explained to the ISO that these failures to provide AS were due to problems with its scheduling system. This was technically true but misleading. Enron wanted the ISO to believe that it was fixing its system to stop making undeliverable AS sales, when in fact we know from the Belden emails that it was fixing the system, not to eliminate the practice of overbidding, but rather to make foolproof the practice of reliably buying back any sold, but non-existent AS capacity. (Exh. No. CA-236)

Enron's attempt to "fix" its system apparently was not fully successful. An ISO email obtained from discovery written by an ISO operator on August 12, 2000, over a month later, complains that Enron's imported AS schedules are not honored if the ISO calls on the import to produce energy in the second half of the hour in which the ISO has asked the unit to be ready to produce energy. This suggests that Enron was again selling AS capacity to the ISO without having that capacity available. (Exh. No. CA-110)

Q. Have you conducted any independent analysis of the prevalence of Get Shorty-type strategies by Enron and other importers?

A. Yes. I have conducted an analysis to assess the prevalence of Get Shorty strategies during the January 2000 through June 2001 period. I have analyzed the extent to which entities engaged in AS buyback strategies to gain insights into whether these entities likely engaged in the sale of non-existent AS. The results of my analysis are presented in Tables G-1 through G-3. Tables G-1 and G-2 compare the extent of AS buyback strategies for generators vs. importers. The AS buyback activities by ISO-internal generators provide a useful benchmark because we know that selling non-existing AS from ISO-internal generation is, for the most part, prevented due to the ISO's capabilities to monitor availability of internal

generation capabilities. The results of my buyback analysis are shown in Table G-1 for ISO-internal generators and in Table G-2 for importers. In each of these tables, I included only entities that have repurchased some of their DA Ancillary Service sales.

Q. What are the results of this comparison of buyback activities for importers and ISO-internal generators?

A. The comparison of AS buyback activities for importers and ISO-internal generators shows following patterns:

- The prevalence of AS buybacks is significantly higher for importers than for ISO-internal generators: when importers were buying back AS, they were buying back a much larger percentage of their DA sales, but in-ISO generators were not. This holds true for the entire January 2000 through June 2001 time period. During January through April 2000, importers repurchased an average of 37% of their DA ancillary service sales while ISO-internal Generators repurchased only 8%. During May through September, importers repurchased 56% while ISO-internal entities repurchased only 15%. During October 2000 through January 2001, repurchases were 84% for importers but only 21% for ISO-internal entities. And finally, for January through June 2001 (the CERS period), average AS buyback of importers accounted for 99% of their DA sales while that number was only 13% for ISO-internal entities.

- **Importers repurchased their DA ancillary service sales much more frequently than ISO-internal generators.** The results show that importers bought back some or all of their DA sales more often than ISO-internal entities. For example, during the CERS period, importers bought back AS during over 3,100 hours while selling AS without buybacks only during 160 transaction hours. In contrast, ISO-internal entities repurchased AS slightly more than 1,000 times while selling AS without buyback more than 10,900 times. A marked discrepancy in the frequency with which buyback strategies were used also exists for the other subperiods.

  These discrepancies between importers and ISO-internal generators strongly suggest that (1) importers were selling AS in the DA markets with the intention of buying much of these sales back in the HA market; and (2) importers likely were gaming the DA markets by overselling during hours when they intended to buyback. These buyback patterns would logically increase the need for the ISO to

over-purchase AS either by purchasing enough in DA to offset expected buybacks, or in HA to cover the buybacks themselves.

Q. Have you identified the Scheduling Coordinators that were most actively pursuing questionable AS buyback strategies?

A. Yes. Given these trends among importers, I have conducted a more focused analysis for individual Scheduling Coordinators whose AS buyback strategies most likely were harmful to ISO operations and constituted Get Shorty-type games. The results of this analysis are shown in Table G-3. (Table G-3 is based on the results presented in G-2.) Based on the results shown in Tables G-2 and G-3, I conclude that the entities that were most likely and most actively pursuing Get Shorty-type AS strategies are Enron, Sempra, Coral, Powerex, the Modesto Irrigation District, Avista, and the City of Azusa.

During the Spring of 2000, Enron was the only importer who consistently used highly questionable AS buyback strategies. During 184 buyback hours, Enron's average DA AS sales exceeded by 65% the AS capacity sold during hours without buybacks (on average almost 63 MW during buyback hours vs. 38 MW in non-buyback hours). During these buyback hours, Enron repurchased about 56% of DA sales.

I find that four importers pursued harmful AS buyback strategies during the Summer period (May 1 through October 1, 2000):

- **Enron.** Enron buyback behavior during the Summer of 2000 was significantly more aggressive than its activities during the Spring. Enron's DA ancillary service sales during buyback hours were more than 3 times larger than its AS sales during hours when Enron did not repurchase AS (192 MW during buyback hours vs. 60 MW during non-buyback hours). On average, Enron repurchased 63% of its DA sales.

- **Sempra**. Sempra repurchased DA ancillary service sales during 204 hours in this period. During those hours with buybacks, Sempra's DA sales were 2.5 times as much as its AS sales during hours without buybacks. When buybacks occurred, Sempra was buying back more than 75% of its DA sales.

- **Coral.** In the Summer period, Coral repurchased DA ancillary service sales during 183 hours. On average, the amount bid into DA ancillary services markets was more than 4 times greater during

hours with buybacks than during hours without buybacks. When these buybacks occurred, Coral was repurchasing more than 90% of the volumes sold in the DA market.

- **Powerex.** During this period, Powerex engaged in AS buybacks on 96 occasions. The DA quantities sold during hours with buybacks were, on average, 14% (or 74 MW) greater during hours when these buybacks occurred than during hours without buyback.

During the Fall/Winter period, Enron appears to have greatly reduced its AS buyback activities, while Sempra and Coral continued to engage in such conduct:

- **Sempra.** For the 155 transaction hours in which Sempra repurchased its DA ancillary service sales, the average volumes sold into the DA market (155 MW) were nearly 3 times greater than the AS sales during hours with no buyback (39 MW). In addition, when these buybacks occurred, Sempra bought back more than 83% of its DA sales.

- **Coral.** During the October through January period, Coral repurchased DA ancillary service sales during 444 hours. Importantly, during these 444 hours, Coral repurchased 100% of DA sales. In contrast, Coral only sold DA ancillary services without buying it all back during 70 hours in this period.

During January through June 2001 (the CERS period), evidence of Get Shorty-type gaming of AS markets is particularly strong:

- **Sempra.** Sempra repurchased 98% of its DA ancillary service sales during 565 hours. When repurchasing AS, its DA sales (averaging 140 MW) were more than 3.7 times higher than its AS sales during transaction hours without buyback (37 MW). Sempra only sold AS without buybacks during 141 hours.

- **Coral.** It appears that Coral completely withdrew from selling legitimate AS during the Spring of 2001. I could not identify a single transaction hour for which Coral did not buy back 100% of its DA ancillary service sales.

- **MID, Avista, and Azuza.** While these three entities had been selling AS to the ISO during prior time periods (with very limited

buybacks), the three entities essentially stopped selling non-short AS sales to the ISO during the Spring 2001 period. MID repurchased 100% of its DA ancillary service sales (averaging 47 MW) during more 1779 hours, while never selling without buybacks. Avista bought back 99% of DA sales (averaging 109 MW) during 534 hours while only selling 49 MW during 18 hours without repurchases. And Azusa bought back 100% of DA sales (averaging 10 MW) during 102 hours, while never selling without repurchases.

Q. Do these results conclusively show that these AS buybacks were Get Shorty-style strategies as opposed to more legitimate repurchase strategies?

A. No, but these results are highly suggestive that the discussed Scheduling Coordinators were involved in Get Shorty-type strategies. The facts that (1) these Scheduling Coordinators would sell significantly more AS in DA markets at times when they were conducting buybacks, and/or that (2) they would rarely sell AS sales without almost complete repurchase of DA sales, strongly implies that the discussed entities either sold non-existent AS to the ISO or simply had no intention of delivering the AS capacity they sold. The ISO itself reached a similar conclusion about the market, indicating that buyback arbitrage "clearly indicates no intent to provide the service but rather take advantage of ISO settlement rules." (Exh. No. CA-112)

Q. Have you seen any evidence of the intent of these importers?

A. Yes. The discovery process has obtained additional evidence that Get Shorty-type strategies were specifically pursued by Enron, Coral, Glendale, and Williams. The evidence on Enron's pursuit of this practice is already discussed above.

Evidence obtained in discovery shows that Coral, which was one of the most egregious users of AS buyback strategies based on my analysis, entered into a joint marketing agreement with the City of Glendale. Documents produced by Glendale include a "term sheet" with trading strategies that Coral and Glendale apparently sought to execute jointly. One of the listed strategies is called "Phantom Ancillary Services," clearly describing a Get Shorty-type game:

> *This strategy works best when Capacity is being purchased at near its cap price by the ISO, and should be used when the generation is not actually available to back the capacity offer. In the Day Ahead Ancillary Services Market offer the capacity at or near the cap price, but never lower than $10 below the cap price. Buy the capacity back in the Hour*

> *Ahead Ancillary Services Market, and arbitrage the value. Generally, your worst downside is the amount by which you set your DA offer below the cap price. (Exh. No. CA-168 at 1.)*

Q. Is there any additional evidence of likely AS repurchase games for other power marketers?

A. Yes. As discussed below, internal generators may have been playing some limited Get Shorty type games from internal ISO generation. In a January 3, 2001 internal Mirant email, a Mirant trader describes the sale of certain AS that will be repurchased at a later time, so that Mirant can "make a sweet margin." While this might be referring to a sell-repurchase strategy based on physically-available resources (either internal or external to the ISO), the email suggests that it is not an innocent strategy by referring to it as "DA Trickery." (Exh. No. CA-34)

Similarly, Williams noted that they have used a strategy of selling "regulation down in the Day Ahead with the intent to purchase it back in the Hour Ahead market" in order to "arbitrage" price differentials between Day Ahead and HA ancillary services markets. (Exh. No. CA-31) While this statement clearly admits that Williams sold AS with no intention of delivering the sold service in RT, evidence obtained in discovery shows that Williams repeatedly sold AS it could not provide. This is illustrated by a Williams email from Mr. Jeff Davis dated August 29, 2000:

> *I sent you another e-mail earlier about reg range... This one is also related to DA selling reg. On 8-28 DA had...10 mw's up HE 23 and 24... HE 23 had 81 mw's reg up. HE 24 had 97 mw's reg up. RT moved 30 ms's for those hours to get the unit to AGC min. Well, 40+81=121. No can do. HE 24 is even worse. We couldn't perform 97 of reg up, even if AGC min was 10! What will it take to get the traders to cease committing the units to schedules they cannot perform? I feel pretty stupid telling the units the same thing over and over again. (Exh. No. CA-21)*

When deposed, Mr. Davis confirmed that Williams was indeed submitting infeasible schedules. He believes that this game occurred over a few weeks around the time of his message, late August 2000. Mr. Davis also indicated that for a period of several months, Williams was scheduling units in a way that was inconsistent with their ramping abilities. (Exh. No. CA-19)

In addition, Dynegy was able to play Get Shorty games from internal generation. In April 2000, Dynegy was selling non-spinning reserves from capacity that was out of service. The ISO notes that "Dynegy again today has Kearny 3 bid (and awarded) 60 MW non-spin but are good for only 30 MW due to some maintenance work." ISO personnel also indicate that problems like this "would never be noticed by the dispatcher unless unlikely and infrequent events force us to call on the non-spin bid." I note that this type of overselling game would not likely be apparent in my Get Shorty analysis. (Exh. No. CA-149 at 3)

D. DOUBLE-SELLING ANCILLARY SERVICE CAPACITY FROM ISO-INTERNAL RESOURCES

Q. If ISO software is monitoring in-ISO resources, can ISO-internal resources oversell AS?

A. The ISO's software makes sure that only physically available AS capacity is awarded by the ISO. This prevents selling non-existent AS in a Get Shorty-type game. However, prior to September 2000, ISO-internal generators could violate AS requirements through a "double selling" strategy. This game requires the intentional violation of the generators' obligation to keep unloaded (*i.e.,* not produce energy from) the AS capacity sold to the ISO, unless the generator is specifically instructed by the ISO to produce energy from that set-aside reserve capacity. Generators can violate their AS obligation through uninstructed generation of energy from the resource that is supposed to remain unloaded.

Prior to September 2000, when the ISO implemented "No Pay", generators pursuing such uninstructed generation from AS capacity would be paid twice. First the generator was paid for keeping the awarded AS capacity unloaded (unless dispatched by the ISO). And second, the generator was also paid the RT price for the energy that was injected into the grid as an "uninstructed deviation." I call this strategy "uninstructed double-selling."

Q. What is the harm from uninstructed double-selling?

A. When the ISO pays a generator to provide AS, it expects that capacity to be available to provide those AS if needed. If the generator is producing energy from that capacity, it is not available to provide the AS that have been reserved by the ISO through its AS payment. The ISO has experienced this problem in the past. This can result in harm from both an economic and a reliability perspectives by causing operational difficulties, raising costs, and possibly even causing the ISO to violate NERC or WSCC operating guidelines.

In February 1999, the ISO filed a tariff amendment with the Commission to eliminate payments for uninstructed double-selling by internal resources (the "No Pay" policy), citing the above harms. The Commission approved this amendment in ER99-896 in its order on February 19, 1999 stating in its order that No Pay would "ensure that AS providers will have no economic incentive to dishonor their commitments and a strong incentive to honor them."

Q. If the ISO's amendment was approved in 1999, why was uninstructed double-selling still a problem in 2000?

A. As noted in the Commission's order, implementing the No Pay policy required the ISO to change its software. The ISO did not complete these software alterations until September 2000. Thus the ISO system was unable to begin implementing its "No Pay" policy until that time. During that period between the Commission's order and the ISO's implementation of No Pay, and despite the fact that the Commission ruled that uninstructed double-selling was inappropriate, I find that certain parties continued to take advantage of this loop hole in the ISO systems.

Q. What analysis have you conducted to analyze uninstructed double-selling prior to implementation of No Pay?

A. I have conducted an analysis to identify potential uninstructed double-selling by the five major generators: Duke, Dynegy, Mirant, Reliant, and Williams. The data signature for AS uninstructed double-selling from ISO-internal resources is quite clear, allowing me to measure the frequency and severity of such double selling.

Q. How did you determine if a generator double-sold their AS awards?

A. I determined how much capacity a generating unit had available during RT operations and compared that amount to the AS capacity that was awarded by the ISO. I calculated for each hour the capacity available to meet a generator's AS obligation as the unit's maximum capacity less the sum of: the unit's HA energy schedule, energy sold as supplemental energy, schedule changes, and uninstructed generation. (I did not deduct any energy that the ISO dispatched from awarded AS capacity). Comparing this measure of available capacity to the capacity awarded as AS identifies whether the resource has double-sold AS capacity.

The results of my analysis are presented in Table H-1 and are summarized in Figure H-1 for the Summer months of 2000. The figure indicates that Dynegy, Mirant, Duke, and Reliant engaged in significant uninstructed double-selling during the Summer of 2000, just prior to the implementation of No Pay policy in early September. The results show for each generator

the portion of the ISO's awarded AS capacity that was double-sold by producing energy with uninstructed generation. This figure clearly indicates that Mirant in particular engaged in this activity throughout the Summer Period, double-selling energy from more than a third of its AS obligation in June of 2000. Duke, Dynegy and Reliant similarly engaged in uninstructed double-selling, although to a lesser extent than Mirant. Williams does not appear to have been actively engaging in this strategy in any material way during the Summer Period (although this may be due to my conservative screens).

XI. SUBMISSION OF KNOWINGLY FALSE LOAD

A. THE STRATEGIES AND THEIR IMPACTS

Q. You noted in your discussion of Ricochet transactions that one purpose of these transactions was to withhold resources from the DA and HA markets in order to profit in the RT market, which could be manipulated more easily. Are there other games that Scheduling Coordinators have employed to withhold supply from the DA or HA markets while shifting that supply into the RT market?

A. Yes. Various Scheduling Coordinators have employed a trading strategy based on the intentional submission of false load information to the ISO. This strategy has been referred to as "Fat Boy" or "Inc-ing Load" in the Enron memos.

In the context of the California power crisis, Fat Boy is a market manipulation game whereby the Scheduling Coordinator files a DA or HA schedule with the ISO that intentionally contains more load than the Scheduling Coordinator has available to serve. Since generation must balance load in the submitted DA and HA schedules, such overscheduling of load allows the suppliers to include more generation in its schedule than it otherwise could. The generation "scheduled" to serve the false load is, of course, no longer available to serve the actual load that is bid into the DA or HA market.

When the supplier runs its scheduled amount of generation in RT, this generation then exceeds the supplier's actual load. (The ISO will determine that the SC's load is below the scheduled amount but that the SC's generation was equal to the scheduled amount.) The difference is treated as an uninstructed deviation and earns the RT market price as a price taker. This de-facto sale of some of the SC's generation into the RT market is precisely what the SC intended in the first place. In effect, the submission of non-existent load information shifts supply resources from the DA or HA markets into RT.

This strategy often is identified with power marketers because generators internal to the ISO and generation-based importers have other ways of selling only to the RT market, including the withholding of generation from the DA and HA markets by bidding only into the RT market or, in the case of internal generation, via intentional uninstructed generation (see the section following). However, Scheduling Coordinators with ISO-internal

generators might also use such Fat Boy-type strategies, to obscure the fact that supply is being withheld from the DA or HA markets.

Q. Do the use of Fat Boy and similar overscheduling practices impose any economic harm or are they legitimate strategies to arbitrage price differences between the DA/HA and the RT markets?

A. It has been argued that these false load strategies are a form of efficient arbitrage between the RT and DA markets. It has also been argued that it is a legitimate strategy that allows importers to sell into the RT market without having to buy transmission service in RT (which, is claimed, may be more difficult to obtain). Overscheduling load would thus allow importers, who wished to have the option to sell into the RT market, to reserve transmission capacity as the false DA schedule is submitted. However, I find both the pure "arbitrage" argument and the "difficult-to-obtain transmission close to RT" unpersuasive as a justification for these strategies.

First, even if overscheduling load was a pure arbitrage strategy and transmission was, in fact, more difficult to obtain close to RT, the overscheduling of load involves the intentional submission of false information to the ISO. Getting around transmission difficulties not faced by ISO-internal generation may reduce economic disparities, but it also evades the operational and reliability reasons why these tariffs and procedures were adopted in the first place. In this case, the ISO believed that its markets worked better overall when DA generation and load schedules were balanced based on schedulers' best estimate of true load served with that generation.

Second, the arbitrage argument is consistent with economic efficiency only if the RT markets were workably competitive. However, as discussed in Part A above, this was often not the case. As discussed in Part A, the RT market could be more easily manipulated due to an almost vertical demand curve and other factors, such as ISO operational considerations. With RT prices that are manipulated and significantly above competitive levels, strategies that would ordinarily act to equalize price differences between the DA or HA market can become tools to transmit some of the market power exercised in RT to these other markets. As I will discuss below, at least one importer (Powerex) consciously employed a two-pronged strategy in which they very aggressively bid into the RT markets to manipulate and increase RT prices while also overscheduling load to benefit additionally from the difference between the manipulated RT price and the lower DA or HA prices.

Finally, I find the argument that "transmission is difficult to obtain close to RT" unpersuasive as a generic justification for overscheduling load. First, there was often more congestion in the DA market than there was in RT operations. This would suggest that it often might have been easier to find transmission capacity close to RT than it was to obtain necessary transmission capacity on a DA basis. Second, to the extent that transmission capacity was available on a DA basis, that capacity may not be available in RT—which creates the risk that DA schedules are cut by the ISO (or a neighboring control area). In fact, a September 14, 2000 email obtained in discovery from Powerex explains that, because of such risks of unavailable transmission capacity, Powerex finds it preferable to sell into the RT market. As the email explains:

> *...one of the reasons why it is preferable to sell into the real time California market as opposed to the forward California market is that sales in the forward market carry risks that the real time sales do not. Our generation is three wheels away from the California border. Furthermore, there is at least one wheel of ISO transmission to get our energy from the California border into the appropriate load zone where we are sinking our energy. In-the-day Transmission de-rates on these paths are a common occurrence. If we are unable to supply a forward market sale to the CISO or CALPX for any reason, we are responsible for the cost of replacing the energy in the hour ahead or supplemental market, regardless of whether the transmission outage is in the Northwest or in California. ... This has had a significant cost to us in the past and is one factor that biases us toward the real time market. (Exh. No. CA-48)*

B. EVIDENCE REGARDING SPECIFIC SELLER "FAT BOY" ACTIVITIES

Q. Have you conducted any independent analysis of the prevalence of overscheduling load?

A. Yes. I have performed an analysis of metered and scheduled load data provided by the California ISO in response to discovery. Table I-1 summarizes the results of this analysis. The table lists all Scheduling coordinators that overscheduled significant amounts of load in at least 20% of the time within a period. The data screen I used identifies events that constitute "significant" overscheduling as those hours for which scheduled load during peak hours is either (1) more than 50 MW greater than metered

load; or (2) more than 50% in excess of metered load.[59] The table shows average metered load, average scheduled load and the average amount ("difference") of overscheduling for the hours with "significant" overscheduling as defined in my data screen. The last column also shows how pervasive (*i.e.*, the proportion of all peak hours in the period) the sellers' overscheduling activity was in each of the four time periods.

Q. What are the results of this analysis?

A. As summarized in Table I-1, the results of my analysis show that Mirant and approximately a dozen importing sellers persistently overscheduled load during all or part of the January 2000 through June 2001 time period. However, this pattern of scheduling false load is not uniform across the 18 month time period analyzed in my testimony:

- **Spring 2000.** My analysis shows that Mirant, California Polar Power Brokers, Enron, Idaho Power, NewEnergy, PG&E Energy Services (an unregulated affiliate of PG&E) and Sempra were actively overscheduling loads, averaging between 15 and 190 MW.

- **Summer 2000.** During this period Mirant, Anaheim, Riverside, Coral, Powerex, Polar, Enron, Hafslund Energy, Enron Energy Services, Pasadena and Sempra were actively overscheduling loads. The overscheduled amounts are noticeably larger than during the Spring on average exceeding more than 300 MW (per hour) for Powerex and Enron, and between 160 MW and 225 MW for Mirant, Polar, Hafslund, and Sempra. With the exception of Polar, these sellers' overscheduling events occurred during 43% to 71% of the analyzed Summer period.

- **Fall/Winter 2000.** The amount of overscheduling continued to increase, exceeding more than 500 avg. MW per hour for Powerex and 420 avg. MW/hr for Enron. Mirant, Anaheim, Hafslund, Enron Energy Services, Duke, Riverside and Sempra overscheduled an average of approximately 210 MW to 350 MW. Most of these sellers overscheduled in 30% to 100% of the analyzed hours (*i.e.*, all peak hours) in that period. Dynegy and Coral overscheduled 90 MW and 550 MW respectively, during 33% to 46% of the hours.

[59] I also analyzed whether the overscheduling pattern identified is consistent even when considering all those hours during which overscheduling has not occurred. This analysis confirmed that overscheduling is the identified hours is not an artifact of uncertain load forecasts and random differences between scheduled and metered load. Figures I-1 through 4 (discussed below) also document this fact.

- **Spring 2001 (CERS Period).** Overscheduling dropped off significantly during the CERS Period, with only Anaheim, and Pasadena overscheduling by an average of 330 MW and 150 MW during 54% and 51% of the analyzed hours, respectively. This drop off in overscheduling as a trading strategy is consistent with the fact that suppliers almost fully withdrew from the ISO's RT market and, instead, sold directly to CERS and at prices that generally were far above the applicable soft cap.[60]

Figures I-1 through I-4 also show false load patterns by comparing on a monthly basis the average of scheduled and metered generation for all peak hours of the month. The differences between the bars for scheduled and metered generation is the amount of uninstructed deviations. The charts also show that some sellers, such as Mirant (*i.e.,* Southern Company) were able to overschedule load without possessing any metered load. Mirant, for example, was able to do so by overscheduling to "virtual" load points, which were created for the purpose of offsetting transmission losses. However, Mirant's scheduled loads were significantly in excess of any amounts that could reasonably be attributed to transmission losses.

Q. Are your findings consistent with other analyses of this trading strategy?

A. Yes. The results of my analysis showing that Enron overscheduled its load by an average of 400 MW during the Summer and Fall/Winter periods, and during 70% to 90% of the hours in those periods, strongly confirms Enron's persistent use of this strategy as discussed earlier in my testimony. These findings, including the drop-off during the CERS period, are consistent with the ISO's analysis of Enron's overscheduling practice, stating that:

> During 2000, Enron routinely overscheduled load by 500 to 1,000 MW… Overscheduling by Enron dropped dramatically in late November and early December, 2000, but resumed in August 2001 through November 2001. (Exh. No. CA-109 at 2)

Q. Is there any additional evidence documenting the use of these scheduling false load strategies by Sellers?

A. Yes. As discussed in Part A Section V, the discovery also shows that the scheduling of false load was often pursued in cooperation with others. For example, the Enron Network Services handbook describes "Ex-Post

[60] El Paso's overscheduling was likely done by or in concert with Enron, which had a marketing agreement with El Paso. See Part A, Section V for additional discussion.

Pricing" strategies, including Fat Boy as well as Thin Man (an underscheduling game). The handbook also provides a list of partners with which Enron may have engaged in Fat Boy games, including Colorado River Commission, EPE, Glendale, Redding, Tosco, and Valley Electric. For most of these partners, Enron expected to have a 50/50 split of any profits or losses. (Exh. No. CA-105 at 515-6) A review of Enron's trader logs indicate that Enron actually did engage in Fat Boy games with at least EPE, Glendale, and Redding, as well as an entity not listed in the handbook, LV Cogen. (Exh. No. CA-74)

In addition to the above, obtained evidence also documents scheduling of false load by the following entities:

- **Coral.** A Coral training manual for new traders discusses advanced trading strategies, including a section called "Load Plays." The discussion of load plays indicates that traders believe it is beneficial to be "long" in the RT markets, the way Coral "balances [its] portfolios is by syncing [sic] the excess mw into one of [its] Load I.D's." This amounts to an overschedule in the DA market. (Exh. No. CA-121 at 5)

- **Dynegy.** In December 2000, one of Dynegy's traders is having a conversation with a person that appears to be in the Dynegy back office. The back office employee is trying to find out why Dynegy is showing a load deviation in August 2000. The trader is asked if he is "basically just sinking some pseudo load, dummy load, whatever, there." (Exh. No. CA-202 at 2) The trader states that he is probably right, and agrees with the assumption that any time there is a load deviation, "it's probably because [the traders] are just doing some dummy load scheduling." (Exh. No. CA-202 at 3)

- **Glendale.** As discussed earlier, Glendale was involved with Fat Boy transactions with Enron. Glendale had internal memos describing the transaction and in an attempt to teach their traders this strategy, quizzed their traders on the strategy. Internal Glendale documents show that Glendale used or intended to use this strategy with Coral once the Coral/Glendale alliance began. (Exh. No. CA-171 at 2)

- **Hafslund.** In July 2000, the ISO conducted analyses to show that Hafslund was scheduling "phantom" loads in the forward markets in

order to arbitrage the PX and ISO RT imbalance market. (Exh. No. CA-149, at 2)

- **Mirant.** In it's response to the Commission's inquiry of trading strategies, Xcel Energy provided Transcripts of conversations between Mirant and Public Service of Colorado traders, discussing over-scheduling load on a joint basis. For example, in an undated conversation, the PSCo trader suggests "Why don't we just do something where we overschedule, overschedule load and share an upside, dude," while the Mirant trader responds "That's fine." (Exh. No. 204 at 38) Similarly, on July 18, 2000, a Mirant trader suggests combining overscheduling load with a congestion game: "...you want to do a congestion type of game plus ex-post..." in response to which PSCo later proposed "lets take that contract stuff...move it to Four Corners and let Southern over schedule load, 25 of it SP and 25 of it to NP for a congestion play." (Exh. No. 204 at 27) These conversations are consistent with my analysis showing the fact that Mirant was one of the most prolific overschedulers.

- **Redding.** Enron's trade book data (Exh. No. CA-74) indicated that Redding and Enron engaged in fat boy games jointly. However, Redding documents also show that traders at Redding were involved in initiating overscheduling games. On June 22, 2000 one of Redding's traders called Sempra, asking if Sempra was interested in "doing an ex-post deal today." (Exh. No. CA-161 at 2) On the same day, a Redding trader also approached Western about doing an ex-post deal. (Exh. No. CA-161 at 3)

- **Powerex.** Internal business planning documents for Powerex show that the company wanted to increase its exposure to imbalance markets.(Exh. No. CA-49 at 1) This is consistent with my finding that Powerex was consistently over-scheduling load during the period from May 2000 through January 2001. Powerex trading systems were designed to include an "oversched" transaction type. (Exh. No. CA-43) Additional discussion of Powerex's fat boy strategies is included in Exh. Nos. CA-41, CA-173 and CA-174.

- **Sempra.** The results of my analysis are similarly confirmed by additional evidence obtained from Sempra. In an August 2000 email, Sempra trader Tim Hanna indicates that the company should attempt to make all deviations be instructed rather than uninstructed.

To do this, Mr. Hanna indicates that Sempra should submit "fake load" to the DA market. (Exh. No. CA-71)

- **Williams.** The obtained listing of Williams/AES trading strategies developed identifies one strategy as "scheduling bogus load." (Exh. No. CA-22 at 2) According to their responses to CA Parties' data requests, Williams frequently scheduled bogus load in the ISO's DA markets between January 2000 and December 2000. (Exh. Nos. CA-28, CA-29).

Q. Did Scheduling Coordinators with ISO-internal generation also use Fat Boy-like strategies?

A. Yes. As the results of my analysis show, ISO-internal generators also overscheduled load. Overscheduling load also allowed ISO-internal generators to withdraw capacity from the DA market and shift that generation into RT as uninstructed deviations. As discussed above, it also allowed generators to combine Fat Boy-like strategies with congestion games. Finally, it appears that overscheduling load may have been used to circumvent some scheduling requirements of RMR contracts.

Q. How can overscheduling of load be used to circumvent RMR scheduling requirements?

A. Generators that selected the "market path" payment option for RMR units had to preschedule their generation bilaterally in the DA market or allow the ISO to enter them into the DA market as a price-taker (*i.e.*, with a bid price of $0). If these Scheduling Coordinators did not want to allow the ISO to pre-dispatch them as price takers, they had to find load that could be used to submit a balanced DA schedules. Mirant is one of the ISO-internal generators that used false load information to create such "balanced" DA schedule. This allowed Mirant to avoid bidding into the PX as a price taker and receive the PX DA price but, instead, be paid the RT price due to uninstructed deviations created by the Fat Boy strategy. This is discussed in a December 2000 Mirant-internal email:

> *As far as the Px bids at $0, we are required to bid those incremental MWs to the Px at $0 to ensure that the MWs get scheduled. Remember, as long as the schedules go to the ISO at the RMR schedule, we are fine. This means that if prices warrant, we can schedule those MWs to the load and not have to bid them in at $0. This will yield us the RT price. If we declared market and bid them into the Px at $0, we will*

receive the PX zonal price. If we declared contract path, we will get our marginal price. (Exh. No. CA-324)

Q. Does Mirant explain why they scheduled fake load?

A. Yes. In its response to CAL-MIR-42 (Exh. No. CA-294), Mirant lists several reasons it schedules fake load. Mirant indicates that the ISO authorized the company to schedule load when it had no metered load "due to the ISO's requirement that Schedule Coordinators must submit balanced schedules." Mirant further indicated that scheduling fake load offered several benefits to the ISO. The first benefit listed is "improved ... availability and efficiency of Mirant's plants." The second benefit listed is an enhancement of reliability "due to more generating resources showing up in a scheduled fashion, thereby reducing the ISO's reliance on the procurement of RT uninstructed energy." Mirant also argues that scheduling fake load was "a direct response to the chronic underscheduling of load by the IOUs." Finally, Mirant argued that scheduling fake load allowed it to schedule RMR generation requested by ISO.

Q. How was Mirant compensated when it submitted a balanced DA/HA schedule of generation against an equal amount of fake load?

A. Metered generation would have been equal to scheduled generation, so there would have been no ISO payment to or charge against the generation. However, the scheduled load was not met by actual load, so Mirant had a negative uninstructed deviation in load. As this deviation was a net contribution of energy to the system, it was paid the RT price.[61] As a result, the effect of scheduling generation against fake load was to earn the RT price for the scheduled generation.

Q. Did Mirant have any other alternative to scheduling fake load that would have resulted in it earning the RT price while abiding by the ISO's requirement that Schedule Coordinators submit balanced schedules?

A. Yes. Mirant could simply have submitted a price taker supplemental energy bid for the generation.

Q. Did scheduling fake load offer the "improved availability and efficiency" benefits that Mirant suggested in the response to CAL-ISO-42?

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[61] After 10-minute settlements were implemented, the uninstructed diviation would be paid the decremental energy price. However, if they were no decrements in any of the six intervals during an hour (which was the prevailing case during the crisis period), the decremental energy price was simply the incremental energy price.

A. No. First, Mirant did not need to schedule fake load to be assured that its units would avoid rapid ramping. Mirant could have simply submitted a price taker bid into either the PX's or the ISO's supplemental energy market during those hours that it wanted to avoid ramping. Alternatively, Mirant could have generated uninstructed. As described above, its revenue would have been the same if it had just generated uninstructed without scheduling fake load.

Q. Did scheduling false load result in the second benefit Mirant listed, "more generating resources showing up in a scheduled fashion thereby reducing the ISO's reliance an uninstructed energy".

A. No. The scheduling of fake load did not necessarily reduce the ISO's reliance on uninstructed energy, nor did it help serve actual load buying from the PX. First, the ISO was not "relying" an uninstructed energy; rather as I explained below, uninstructed generation was a problem both from a reliability and economic perspective. Second, Mirant had several options other than scheduling fake load that would have resulted in its generation "showing up in a scheduled fashion." In particular, it could have bid into either the PX's markets or submitted a supplemental energy bid.

Q. Is there any basis to argue that "scheduling to load was a direct response to chronic underscheduling of load by the IOUs?"

A. No. This argument implies that Mirant could not have sold its energy in the PX because there was more generation bid into the CalPX than there was load to buy it. Dr. Stern makes clear the fallacy of this suggestion. Furthermore, even if Mirant wanted to sell its power in the RT rather than the DA market, it could have bid into the RT market any time it wanted to, without the need to submit a false schedule.

Q. Is the need to schedule RMR units DA a legitimate reason to schedule fake load?

A. No. Being called on to provide RMR generation by the ISO did not require Mirant to schedule false load. As noted in the email itself, Mirant could just have bid its resources into the PX DA market, which does not require a balanced schedule. The email shown above clearly shows that the rationale for scheduling false load is an economic motive on Mirant's part. This motive is merely that Mirant believes that the price received in RT, which it would receive for uninstructed generation from its RMR unit if it scheduled fake load, is expected to be more favorable than the PX DA zonal price.

Q. In summary, does Mirant's response to CAL-MIR-42 provide any legitimate explanation for scheduling generation against fake load rather than bidding into the PX or the supplement energy market?

A. No. Mirant clearly could have achieved all the benefits they argue were a result of scheduling fake load by simply bidding into the DA market. In addition, they could have scheduled their RMR units through the DA market as well. There is nothing in the response to CAL-MIR-42 that justifies the use of fake load scheduling relative to bidding into the PX.

Q. Are there any economic or reliability concerns associated with Mirant's behavior?

A. Yes. First, Mirant's strategy is based on intentional submission of false information to the ISO in order to evade ISO rules. While this strategy might have been more profitable for Mirant, this evasion of ISO rules also created reliability concerns and additional costs to California's customers.

The reliability concerns associated with this strategy are specifically addressed by the Commission in a March 31, 2000 Order accepting ISO Amendment No. 26. (Docket ER-00-1265) This amendment modified RMR dispatch procedures with the intent of ensuring that energy from RMR units dispatched by the ISO is scheduled against demand in the forward market. In this order the Commission agreed with the ISO that the pre-scheduling requirement will reduce excess generation situations that causes operational problems for the ISO. By creating "uninstructed deviations," Mirant's Fat Boy strategy leads to the very excess generation situation that the ISO and the Commission tried to avoid. The previously-noted email message was sent nine months after the Commission accepted this amendment.

XII. UNINSTRUCTED GENERATION GAMES

A. THE STRATEGIES AND THEIR IMPACTS

Q. What are uninstructed generation games?

A. Uninstructed generation refers to a difference between the level of output for a generator that is instructed by the ISO and the generator's actual output. Uninstructed generation games refer to strategies with the common element that generation is intentionally produced within the ISO or imported at levels higher than the levels dispatched by the final HA schedule plus the ISO's instructed RT generation (including supplemental or OOM energy). Such deviations from instructed dispatch levels are known as uninstructed deviations in ISO parlance.[62] Uninstructed deviations may be part of an economic withholding game intended to bid up the RT price while minimizing the cost of such manipulation.

I have identified three variations of uninstructed generation games, two that rely on uninstructed overgeneration (*i.e.*, positive "uninstructed deviations") and one that relies on uninstructed under-generation (*i.e.*, negative uninstructed deviations).

Q. What are the two games related to positive uninstructed deviations?

A. In the first variant, a generator bids high into RT market in an attempt to drive up market price. If the ISO does not select the high RT bid, the generator decides to run "uninstructed" in order to receive the RT price.[63] While this RT price is below the generator's bid, it is still above the generators' costs or else the generator would not produce uninstructed energy. I refer to this strategy as "uninstructed fallback."

The second version of this strategy is to refrain from placing any RT bids or "hold back" generation from bidding into the DA and RT markets in an attempt to force the ISO into OOM purchases. After the ISO completes its OOM purchases, some or all of the generation not sold as a result of the ISO's OOM purchases is run uninstructed to earn the RT price. I refer to this strategy as "pure uninstructed."

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62 Another common term is "price-chasing".

63 After the 10 minute settlement was implemented by the ISO in September of 2000, positive uninstructed generation received the "DEC" price. However, this "DEC" price was generally equal to the "INC" price due to the fact that decremental generation was rarely needed in the operating hour. (Instead, positive uninstructed generation simply reduced instructed RT generation.) I will not distinguish between INC and DEC prices in this discussion of uninstructed generation but simply refer to the RT price.

Q. How does the ISO accommodate positive uninstructed deviations?

A. The ISO accommodates uninstructed deviations by dispatching more or less energy from the BEEP stack (RT supply curve). Generation that shows up as a positive uninstructed deviation is effectively bid into RT at a price of zero. Thus, in contrast to submitting high bids into the RT market, providing energy via uninstructed generation may actually lower the market clearing price unless, of course, the RT supply curve was very flat in the relevant range. This appears to have been the case during the time period when this strategy was employed.

However, the fact that uninstructed generation essentially acts as a $0-priced bid into the RT market is less consequential because generators can closely monitor the RT price. This makes it possible for the generator to optimize uninstructed generation by observing the RT price and ensure that its uninstructed deviation does not depress the RT price below the generator's profit-maximizing price level.

Q. What is the economic significance of uninstructed fallback and pure uninstructed games?

A. Both of these uninstructed generation strategies are games that allow manipulation of the ISO's RT and OOM markets, essentially through economic withholding, while reducing the cost associated with such the withholding strategy. If the generator could not run uninstructed, the risk of such a strategy is that a unit would not be dispatched at all. These costs are reduced because the generator can intentionally run uninstructed and earn the RT price (instead of not earning anything on the withheld capacity) even after the ISO rejected the generator's inflated bid or did not select the generator for OOM purchases.

The economic interpretation of these two strategies differs slightly. In economic terms, uninstructed fallback takes advantage of the fact that the ISO could not prevent generators from evading the auction rules. For auctions to function properly bidders must bid according to the auction rules and the winners selected accordingly. Losers should not be permitted to sell their product at the price winner's bid to receive. If they did, losers in a supply-constrained auction market would do just what sellers apparently did here: they would hold back on bidding, determine whether demand drives up the winning auction price, and then put their supply on the market. Indeed, the very keystone of the CA market design – flawed though it may have been – was to require all sellers to sell to CA IOUs solely through one auction market, with the intent that competition between sellers would drive prices down. The uninstructed fallback strategy turns

the auction process on its head, lowering the "cost" of manipulative bidding strategies with predictably detrimental results.

A similar economic interpretation applies to the pure uninstructed strategy. The main difference here is that, instead of bidding high and then running uninstructed when not selected by the ISO, the generator does not bid at all. However, the same economic logic applies to non-bidders in auctions as to losers. Rewarding sellers who withhold any bid at all from the RT market with later sales at that market's winning price has exactly the same adverse economic effects as rewarding sellers who bid high, lose, and still sell. An important difference between the pure and fallback uninstructed game is, however, that the withholding of bids may force the ISO into OOM purchases.

As a result, pure uninstructed deviations offer a low-risk avenue of inducing OOM purchases. Bids are withheld in the hope that the ISO will call the unit to provide OOM energy. If the ISO does not make an OOM call to the unit, then it can run uninstructed and earn the RT price. Since the ISO is only likely to need OOM energy when the market is tight, the RT is likely to be at or near the price cap. Thus the upside of the strategy is earning more than the price cap on an OOM sale and supporting the RT through physical withholding. The downside is to run uninstructed and earn the RT price that is very close to the cap. The economic harm from pure uninstructed consequently may be far greater because, particularly starting in December of 2000, the cost of OOM purchases often exceeded the RT price cap and OOM sales were able to evade the additional scrutiny imposed on the sales into the ISO's RT market.

Q. What is the third variant of uninstructed generation games you have identified?

A. The third variation of uninstructed generation involves what has been referred to as "self help" during the Spring of 2001, the CERS Period. Under this strategy a generator would be asked to provide power under purchases made by CERS, often at the request of the ISO. The generator would then decide to produce *less* than the instructed amount of generation while still attempting to obtain payment for the full amount from CERS. This shortfall in RT generation (*i.e.,* the negative uninstructed generation) will need to be supplied by the ISO and often, at the ISO's instructions, will have to be procured and paid for (again) by CERS as an additional OOM purchase at uncapped prices.

The ISO subsequently charges the cost of imbalance energy to the generator, which declines payment and insists that the owed amount be

treated as an offset against the generator's amounts due from the ISO. The desired end-result of this game is that the generator receives payment from CERS that is used to reduce the generator's outstanding balance with the ISO. The game, however, involves (1) the intentional non-performance by the generator; (2) the attempt to hide the non-performance from CERS to receive full payment for energy that was not produced; while (3) forcing the ISO (through CERS) to incur the expense to repurchase the undelivered amount of energy at high OOM rates. This is possible because CERS needs to rely on the generator's representation of performance because the agency neither can independently verify that the generator actually produced the agreed upon and paid-for energy nor, due to confidentiality provisions, is able to obtain from the ISO the generator's metered output data.

Q. What are the reliability implications of uninstructed generation games?

A. Uninstructed generation, particularly positive uninstructed generation, can be harmful to ISO operations. In response to large amounts of positive uninstructed deviations, the ISO issued a market notice on the topic on July 31, 2000. This notice clearly stated that uninstructed deviations are not allowed and describes the reliability problems they can cause. The market notice also includes a list of actions that will be pursued against generators that continue to exceed uninstructed generation thresholds designated in the order. The text of the notice reads:

> *This notice is to advise all Scheduling Coordinators and owners of Generation in the ISO Control Area that the ISO is issuing an operating order for July 31, 2000, that all resources must follow final Hour Ahead Schedules, as adjusted by RMR Dispatch Notices, or by Dispatch instructions verbal or electronic, on AS or Supplemental Energy bids. NO UNINSTRUCTED DEVIATIONS WILL BE ALLOWED. Section 2.3.1.2.1 of the ISO Tariff requires Market Participants in the ISO Control Area to "company fully and promptly with the ISO' s operating orders." Any Generating Unit with RT output that reflects an excessive deviation from the RT output consistent with its Final Hour Ahead Schedule as adjusted by Dispatch instruction, and assuming a 20 minute ramp across the top of the hour for hourly Schedule changes, will be deemed to have failed to comply with this operating order. For the purpose of this determination, an excessive deviation shall be the smaller of 10% of a Generating Unit's maximum capability, or 10 MW. The only exception to this finding is a Generating Unit that*

provides the ISO with timely notification of a unit outage or derate. Failure to comply with this operating order threatens the reliable operation of the ISO Control Area. In particular, uninstructed incremental deviations by Generating Units that are "chasing" the BEEP Interval Prices published by the ISO are directly responsible for the frequency excursions the ISO experienced June 13, 2000. The ISO will take the following actions with respect to those Generating Units that fail to comply with this Operating Order: 1) ISO Management will deliver a report to the ISO Governing Board the provides a copy of this notice, and a comparison of the instructed and actual output profile for each Generating Unit that fails to comply. 2) The ISO will assign any WSCC RMS penalties associated with frequency deviations to the Generating Units that fail to comply. (Exh. No. CA-238)

B. EVIDENCE REGARDING SPECIFIC SELLERS AND STRATEGY VARIANTS

Q. Have you analyzed if generators were engaging in uninstructed over-generation games?

A. Yes, I have. To test whether uninstructed deviations likely related to this particular form of economic withholding, I have determined which suppliers show a pattern on significant positive uninstructed generation. Because some uninstructed generation likely is a normal part of plant operations, and in fact may be the result of providing "regulation" services to the ISO,[64] I have screened for large amounts of uninstructed generation over the entire January 2000 through June 2001 time period. In this screening analysis I determined on a monthly basis all those generators with (1) average portfolio-wide uninstructed generation levels in excess of 7% of metered generation; and (2) average unit-specific uninstructed generation that exceed 10 MW (or one-tenth of the unit's capacity, whichever is less) during at least 20% of the hours in the particular month.

The results of this data screen are presented in Table J-1. The Table documents that three out of the Big Five generators—Mirant (*i.e.*, Southern Company), Reliant, and Dynegy show significant uninstructed generation during the Summer of 2000 (May through August), with some large additional uninstructed by individual suppliers during the Fall 2000 and early Spring 2001. Of these three generators, Mirant shows the most

[64] Generating units that provide regulation service produce more (or less) power than their scheduled amounts. These differences are also shown as uninstructed generation in the ISO's data, even though they are not the result of deviations from ISO instructions.

persistent use of uninstructed generation, exceeding metered generation by 13% to 23% (on a portfolio basis) during the Summer of 2000. During the same time period, Reliant's and Dynegy's uninstructed generation was in the 7% to 8% range. During the Fall and Winter, Mirant produced uninstructed generation equal to 8% of portfolio-wide metered generation in November 2000, Dynegy produced 14% uninstructed in December, and Reliant generated 7% uninstructed in February 2001.

This pattern of very high uninstructed generation by three out of the Big Five generators is consistent with the economic fundamentals over this period. During Summer 2000, price caps were still high ($750/MWh in May and June, $500/MWh in July, and $250/MWh only starting in the beginning of August) while production costs (in particular natural gas costs) were still low. This made bidding high and "falling back" to the RT price a very attractive option. During the supply constrained periods in November and December, a pure uninstructed generation strategy was likely more attractive (and consistent with significant OOM purchases by the ISO), although running at the capped RT price was less attractive than in the Summer due to higher natural gas (and NOx) costs.

Q. Is there any evidence suggesting that these significant amounts of uninstructed over-generation would be possible without reducing the RT price?

A. Yes. During the time periods when we have identified spikes in uninstructed deviations, there were often a thousand MW bid into the RT time market at or near the price cap. Therefore, running uninstructed would assure a generator of getting paid close to the price cap without substantially lowering the RT price.

Q. Have you analyzed the extent to which these suppliers might have pursued a "fallback uninstructed" generation strategy?

A. Yes. There are some examples with fairly clear patterns of a uninstructed fall back generation strategy for Mirant. ISO data strongly imply that the company pursued an uninstructed fallback strategy during July and August of 2000.

The signature of such an uninstructed fallback strategy is a unit that has uninstructed deviations roughly equal to their quantity bid at prices greater than the RT price. I have calculated the average on-peak MWs that were bid above the RT price for individual generating units with significant uninstructed generation (as defined in my data screen), and compared these MWs bid above the RT price with the amount of uninstructed generation during the same on-peak hours. This analysis shows, for example, that

Mirant's bidding and uninstructed generation pattern shows a close relationship between these two variables. This is shown in Figure J-1 for July 2000 and in Figure J-2 for August of 2000. In July and August, Mirant's average uninstructed deviations are quite similar to the average quantity bid at prices greater than the price cap. That is, Mirant's bidding is very consistent with using uninstructed deviations as a hedge when bidding high in an attempt to drive up RT prices. The close correlation between bids above the RT price and the amount of uninstructed generation across all 13 generating units shown on the chart strongly implies that Mirant pursued an uninstructed fallback game during these two Summer months.

Q. Is there any evidence pointing to a "pure uninstructed" generation game?

A. Yes. Figure J-3 provides an example with a strong signature of a pure uninstructed generation game by Dynegy. The figure shows for Dynegy on a portfolio basis the daily on-peak amounts of DA/HA generation schedules, RT Energy (and undispatched AS capacity), OOM purchases, and uninstructed generation. The figure shows unusually large amounts of uninstructed generation on December 7 and December 8, 2000. These two days also show that DA/HA generation is unusually low and Dynegy has not sold any RT Energy or AS capacity. However, during these very same days Dynegy also shows unusually large amounts of uninstructed generation while selling record amounts of OOM energy to the ISO. In my view, this combination of low DA/HA generation schedules, zero RT (or AS) sales to the ISO, and record OOM sales while producing significant amounts of uninstructed energy, likely implies the pursuit a pure uninstructed generation strategy.

Q. Do you have any additional specific information regarding Dynegy's use of this "pure uninstructed" game?

A. Yes. We have obtained phone transcripts between Dynegy and ISO operators that detail Dynegy's operation of specific units during early December 2000. Dynegy apparently had an agreement with the ISO that specified the price the ISO would pay for OOM energy. During these calls, the ISO would attempt to determine whether units were bid into the market or if the ISO would have to make an OOM call to get the units to run. For instance, on December 12, 2000 the following conversation between Dynegy and the ISO took place:

> *Mike (ISO): Okay. The Encina 1 through 3 –*
> *Ware (Dynegy): Okay.*
> *Mike (ISO): and El Segundo 1 and 2, we want them to remain on tomorrow of course.*

Ware (Dynegy): Okay.
Mike (ISO): And we were under the impression, as of this amendment 33 with the FERC filing, that all those out of market were going to become system requirements, but we'll call it out of market and we'll let the powers to be argue about it.
Ware (Dynegy): Yeah, yeah, that's all I can do.
Mike (ISO): That's all I can do too. We'll just let them argue.
Ware (Dynegy): Okay.
Mike (ISO): And I'll log it as such. I'll say it's out of market, but we were under the impression that it was supposed to be system requirements now, and we'll let the people smarter than us argue about it.
Ware (Dynegy): Okay. I'll start up my minimum loads then.
Mike (ISO): Yeah, minimums all the way around, and then you're going to play the market with these things?
Ware (Dynegy): Yeah, you'll just call us when you out of market them.
Mike (ISO): Okay, So we are going to – or system requirement or whatever you want to call it.
Ware (Dynegy): Yeah.
Mike (ISO): And these are going to be in the market or are you going to be taking only calls on them.
Ware (Dynegy): Yeah.
Mike (ISO): Yeah, so they're going to be going in the market; correct?
Ware (Dynegy): We're not bidding in supplementals if that's what you're asking.
Mike (ISO): So it will take calls to keep them where we want them.
Ware (Dynegy): Yeah, it will take calls to keep it where you want it.
Mike (ISO): And have we been making those calls, or have they been in the market today.
Ware (Dynegy): No, you all have been making the calls. (Exh. No. CA-305)

Most of the fundamentals of the "pure uninstructed" game I have described are contained in the above conversation. In other words, Dynegy first asserts it will not bid its units into the market but will respond to the ISO's

OOM instruction per the agreement in place. This is a clear attempt to induce an OOM call. The final piece of the game, running uninstructed if no OOM call is made, is evident in Figure J-4 that shows Dynegy's uninstructed generation for the units discussed in the above conversation. In this case, because the ISO did not make any OOM purchases from the units, Dynegy ran them uninstructed.

Q. Is there any additional evidence documenting that generators' actually pursued such intentional uninstructed over-generation games?

A. Yes. Additional evidence from discovered documents concerning specific sellers includes:

- **Mirant.** A September 2000 presentation entitled "Southern Energy California and SCEM DA and Real-Time Processes" sets forth the company's DA and RT operating procedures. The company's discussion of its RT process emphasizes to "monitor 10 minute incremental/decremental price" and "adjust" its resources in response to the observed RT price movement. (Exh. No. CA-325)

- **Williams.** Evidence produced in discovery indicates that Williams had a strategy called "over generate/under generate (uninstructed deviation)." (Exh. No. CA-22 at 2). When asked about uninstructed games, a Williams employee said "[t]hat if the uninstructed price or ex-post price was higher than say what might be our cost or whatever decision that uninstructed deviation did occur." (Exh. No. CA-162, at 20) The witness was unaware of whether these deviation games were conducted in conjunction with any bidding practices as part of an uninstructed fallback game.

- **Sempra.** An internal Sempra email notes that the company has "been doing a good job of communicating to the plant operators to over or under generate based on the uninstructed SP15 energy price." (Exh. No. CA-66) As noted in Part A Section V, the fact that Sempra did not own ISO-internal generation also suggests that Sempra's uninstructed generation strategy was implemented through cooperation with others.

- **Reliant.** A 6-point description of trading strategies obtained in discovery describes that Reliant would "submit a supplemental hourly bid at $250" into the ISO's RT market using other entities' names in an apparent attempt to "camouflage" Reliant's own bidding behavior. The strategy then provides to (1) "supply" the power if the

bid is taken (*i.e.*, if Reliant is "called upon"); or (2) to "supply from units or ex-post" if "hourly is not available from" the ISO (that is, the ISO has not "selected" or not "called upon" Reliant to supply power under its high-priced, $250/MWh bids). (Exh. No. CA-56) This clearly implies that Reliant was pursuing an uninstructed fallback strategy of bidding high but running uninstructed if the bid is not taken by the ISO. While the document is undated, the $250 bid price suggests that the strategy applied to the period starting in August 2000, when the ISO's bid cap was set at that level. Reliant's significant uninstructed deviations for August 2000 as identified in my screening analysis would be consistent with that time frame.

Q. You also explained that "self help" is an uninstructed game based on intentional under-generation. Is there any evidence that suppliers might have pursued such a "self help" strategy?

A. Yes. I have analyzed ISO data that suggests that several suppliers, in particular Duke, might have pursued "self help" during the Spring of 2000.

Q. What ISO data have you analyzed to come to that conclusion?

A. I have first analyzed sellers' amounts due to the ISO based on "market certificates" for the months of January 2001 through June 2001, the period in which CERS purchased power on behalf of the ISO. These market certificates were provided by CERS and are produced as Exh. No. CA-124. As I have explained above, one signature of "self help" is that suppliers owe money to the ISO for imbalance energy "purchases" due to the intentional undersupply of generation.

Q. Does the ISO settlement data show any significant amounts that generators owe to the ISO during the CERS periods?

A. Yes. The settlement data shows that during the Spring of 2001, four suppliers owed significant amounts to the ISO. These four entities are Duke, Powerex, Idaho Power, and the City of Pasadena. The amounts owed by these suppliers based on ISO market transactions are shown in Table J-2 in Appendix J of Exh. No. CA-2. The Table shows that Duke owed more than $6 million and $18 million to the ISO for April and May 2001 market transactions. Powerex owed between $1 million and $8 million in the months of January through June 2001; Idaho Power owed between $600,000 and $11 million during the same months, spiking at $11 million in March 2001; and Pasadena owed $3.3 million in April 2001.

Q. Are these amounts owed to the ISO clear evidence of "self help"?

A. No. These amounts owed to the ISO are only indicators of potential "self help" by these suppliers. To provide meaningful evidence that these

suppliers pursued self-help strategies also requires showing that the suppliers were significantly under-generating relative to scheduled or promised generation dispatch levels. Such under generation relative to scheduled or promised dispatch levels would show up as large negative uninstructed deviations.

Q. Have you found that any of the suppliers listed in Table J-2 had, in fact, such large negative uninstructed deviations?

A. Yes. I found that Duke had unusually large negative uninstructed deviations during the Spring of 2001. Figure J-5 compares these negative uninstructed deviations with the amounts that Duke owed to the ISO during the same months. The chart shows that the amounts owned to the ISO in April and May of 2001 correlate closely with Duke's significant negative uninstructed generation for these two months. For April and May the amounts due to the ISO are $6 million and $18 million, while negative uninstructed deviations are approximately 20,000 MWh and 65,000 MWh. This relationship implies that Duke likely pursued "self help" during March, April and May of 2001 by under-generating relative to promised dispatch levels.

Q. Is there any specific evidence that other suppliers might have pursued self help as well?

A. Yes. Self help by Mirant is cited in an August 2001 ISO internal email. The ISO notes that, by mid-July, Mirant had become a debtor to the ISO (See Exh. No. CA-149 at 7-8). My review of ISO data indicates that Mirant also had negative uninstructed generation throughout May and June, suggesting that Mirant appears to have pursued "self help" during the discovery period as well. (See Figure J-6) Finally, the ISO investigation of Mirant notes that the self help strategy causes reliability problems because it puts additional strain on the RT market.

Q. Does this conclude your analysis and discussion of trading strategies?

A. Yes, it does.

XIII. POTENTIAL MISREPORTING BY RELIANT

Q. What analysis do you present in this last part of your testimony?

A. I present my evaluation of Reliant's Transaction Reports for the second and third quarter of 2000 ("Quarterly Report" or "Report"). These two quarterly reports were filed by Reliant with this Commission on July 26 and October 25, 2000 under Docket No. ER99-1801. (Exh. No. CA-201) They report Reliant's purchases and sales for the April through September, 2000 period.

Q. What aspect of Reliant's Quarterly Reports did you evaluate?

A. I evaluated if Reliant has accurately reported its sales to the California ISO.

Q. What does Reliant report as its sales to the ISO?

A. For the period from April through June, 2000, Reliant reports that it sold to the ISO in "SOCAL" (Southern California) a total of 6855 MWh of "Daily" "Firm" energy at prices ranging from $15.34 to $290.63 (see Second Quarter Report at page 18). Similarly, from July through September of 2000, Reliant reports "daily" firm sales to the ISO in Southern California of a total of 20,625 MWh at prices of up to $261.89; for this period, Reliant also reports "daily" firm sales into Northern California of 28,419 MWh at prices of up to $245.75 (see Third Quarter Report at page 18).

Q. How have you evaluated whether Reliant has accurately reported its sales to the ISO?

A. I have used the ISO's own data to compare the prices of sales to the ISO in Southern California as reported by Reliant to the prices of obtained by the Reliant for sales in the ISO's Imbalance Energy Market as reported by the ISO.

Q. What are the results of this price comparison?

A. The results of this price comparison are shown in Table K-1 in Appendix K of Exh. No. CA-2. The table shows that Reliant appears to have greatly understated the maximum prices it obtained for sales to the ISO.

As reported in row [2] of Table K-1, the ISO data for *hourly* prices obtained by Reliant in Southern California (*i.e.*, SP15) shows that the obtained prices exceeded Reliant's reported maximum price during more than 100 hours in both the second and third quarter of 2000. As reported in row [3] of Table K-1, the ISO data shows that the maximum hourly price obtained by Reliant was $750 per MWh in the second quarter and $500 per

MWh in the third quarter. In both quarters, these ISO-reported maximum prices obtained by Reliant greatly exceed Reliant's reported maximum price of less than $300 per MWh.

Q. You have compared prices for sales that Reliant appears to report on a *daily* basis with *hourly* prices from the ISO's own data. How does this apparent discrepancy between daily and hourly values affect the results of your price comparison?

A. The apparent discrepancy between Reliant's "daily" data and the hourly data from the ISO does not affect my conclusion.

Because I was not certain if Reliant's reported prices refer to hourly values or daily averages, I have also calculated from the ISO's data the daily weighted average of prices obtained by Reliant. Row [4] shows that the daily average price obtained exceeds Reliant's reported maximum price on 15 days in each of the second and third quarter of 2000. As shown in row [6], the ISO data shows that the maximum daily average price obtained by Reliant was $679 for the second quarter and $464 for the third quarter. As reported in row [5], these maximum daily average prices were reached on June 14 and July 31, 2000. Again the prices obtained by Reliant as reported by the ISO greatly exceed the prices reported by Reliant. It thus appears that Reliant has misreported to the Commission its transactions data of sales to the ISO regardless of whether prices were reported on a daily average or hourly basis

Q. Does this conclude your testimony?

A. Yes it does.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant	)	
v.	)	Docket Nos. EL00-95-069
Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.	)	
Investigation of Practices of the California Independent System Operator and the California Power Exchange.	)	Docket Nos. EL00-98-058

AFFIDAVIT OF PETER FOX-PENNER

I declare under penalty of perjury that the foregoing is true and correct.

Executed on February 25th, 2003.

[Name]

Contains Protected Material
Not Available to Competitive Duty Personnel

California Parties' Errata for Exhibit No. CA-1: Prepared Testimony of Dr. Peter Fox-Penner on Behalf of the California Parties

Page	Line	Correction
6	22	"40%" should be "45%"
6	24	"12%" should be "15%"
9	5	"that during for" should be "that for"
10	17	"December" should be "December 2000" "Mite" should be "MMBtu"
12	3	Insert "Exh. Nos. CA-273 and" before "CA-285"
14	fn. 3	"were the AS market," should be "also included the AS market,"
22	29	Delete "in OOM purchases and RT markets"
40	8	Add "(See Exh. Nos. CA-52 and CA-296)."
45	10	Insert "(Exh. No. CA-168 at 1-2)" before the period.
45	24	"email from" should be "Enron email"
46	9	"email, a" should be "email, an agreement between Enron and the Imperial Irrigation District ("IID") is proposed in an Enron email (Exh. No. CA-159), a"
48	4	"CA-120" should be "CA-210"
48	6-9	Delete paragraph (duplicative of lines 1-4)
50	2	"power" should be "lower"
50	5	Add "Other examples of such information sharing are illustrated in Exh. Nos. CA-135, CA-249 and CA-257." after the period.

(Continued)
California Parties' Errata for Exhibit No. CA-1: Prepared Testimony of Dr. Peter Fox-Penner on Behalf of the California Parties

Page	Line	Correction
61	23	"Figure 11" should be "Figure 10"
61	31	"Figure 11" should be "Figure 10"
69	fn. 30	"John 21-22" should be "June 21-22, 2000"
70	Table Row:Dynegy	"1000-1500 MW less" should be "about 700 MW less"
70	Table Row:Mirant	"approximately 1500 MW" should be "approximately 2000 MW"
70	20	"the in August" should be "the PX in August"
71	20	"more than 5% if" should be "at least some of"
72	22	"Figure 6" should be "Figure 7"
72	24	"Figure 7" should be "Figure 8"
73	21	"$700" should be "$600, see CA-10 at 103 to 117"
74	12-14	"$1,600/MWh" should be "$1,400/MWh" "$1,500/MWh" should be "$1,000/MWh" "$300/MWh" should be "$200/MWh"
91	22	Add "(Exh. No. CA-2 at 88)" after "Figure D-7"
91	32	Add "(Exh. No. CA-2 at 66)" after "period"

(Continued)
California Parties' Errata for Exhibit No. CA-1: Prepared Testimony of Dr. Peter Fox-Penner on Behalf of the California Parties

Page	Line	Correction
92	5	Add "(Exh. No. CA-2 at 68)" after "Table D-1"
92	32	Add "(Exh. No. CA-2 at 174)" after "Figure I-5"
93	12	Add "(Exh. No. CA-2 at 167)" after "increased"
94	7	Add "(Exh. No. CA-2 at 146)" after "Figure E-2"
94	27	Add "(Exh. No. CA-2 at 183)" after "Figure F-2"
95	16	Add "(Exh. No. CA-2 at 164)" before the period
95	31	Add "(Exh. No. CA-2 at 162)." after the period
95	37-39	Add "2000" after "November", "June" and "December"
101	18	"request" should be "Docket"
104	1	"marketing" should be "market"
104	11	Add "so" after "were"
109	Fn. 38	"CA-40" should be "CAL-40"
112	30	"such" should be "this about"
115	9-17, 22-29	Format as quotation: double-indent and italics
118	32	"the BC Hydro" should be "the BC Hydro system and not sold to third parties – which includes 1,205 MWh of exports to Canada under Stage 3 emergency conditions on January 26, 2001 (Exh. No. CA-41 at 23 and CA-2 at 72) and 366 MWh of exports under Stage 1 and Stage 2 emergency conditions on December 13, 2000 (Exh. No. CA-41 at 22, CA-38 at 2, and CA-2 at 68)."

(Continued)
California Parties' Errata for Exhibit No. CA-1: Prepared Testimony of Dr. Peter Fox-Penner on Behalf of the California Parties

Page	Line	Correction
118	Fn. 41	"CA-38 at 3" should be "CA-38 at 2"; "26, 213" should be "26,213 MWh"; and "addition energy" should be "additional energy"
121	4	"at 37" should be "at 36"
123	5	"Figure Ricochet 1" should be "Table D-1"
123	Fn. 42	"he" should be "the implicated trader, Michael Driscoll"
125	14	"Pacificorp" should be "PacifiCorp Power Marketing"
125	27	"are to" should be "are equivalent to"
125	Fn. 43	"every" should be "ever" and "CA-320" should be "CA-328" and add "at" after "CA-105"
126	1	"This incentive" should be "This provides an incentive"
126	3	"rate" should be "rate"
127	1	"STRATEGIES: CUT" should be "STRATEGIES: DEATH STAR, CUT"
128	35	"relief raising" should be "relief, raising"
133	27	Add "274-5" after ",605, 696, and 873"
134	8	Add "(Exh. No. CA-160)." after the period.
136	18	"July 22, 2000" should be "November 19, 2000"

(Continued)
California Parties' Errata for Exhibit No. CA-1: Prepared Testimony of Dr. Peter Fox-Penner on Behalf of the California Parties

Page	Line	Correction
161	17	"This prevents" should be "This generally prevents"
172	2	"price" should be "cost"
172	37	Change "ISO" to "MIR"

California Parties' Errata for Exhibit No. CA-2: Appendices to Prepared Testimony of Dr. Peter Fox-Penner on Behalf of the California Parties

Page	Line	Correction
144		Two pages of "Table E-3" were inadvertently omitted form the filed exhibit. These pages, 144a of 183 and 144b of 183, are attached. For clarification, "Table E-3, Page 1 of 3" should be added as a footer to page 144.
152	Total	"22,486" should be "22,086"; "357" should be "349"
153	Total	"5,287" should be "4,887"; "72" should be "64"
153	Monthly Average	"1,037" should be "958"; "14" should be "13"

California Parties' Errata for Exhibit No. CA-4: Appendix A to Prepared Testimony of Dr. Gary A. Stern on Behalf of the California Parties

Page	Line	Correction
6	Lower	Left line showing May 2000 supply curve should be dashed, not solid
13	Upper	In label box, solid line should be identified as "Aug-99"
22	Lower	"Enron July Aggregated Net Supply Curves" should be "MIECO July Aggregated Net Supply Curves"

California Parties' Errata for Exhibit No. CA-5: Prepared Testimony of Robert J. Reynolds, Ph.D. on Behalf of the California Parties

Page	Line	Correction
22	14	"margin" should be "marginal"
52	fn. 38	Text of footnote should be "GADS refers to the Generating Availability Data System (GADS) database maintained by the North American Electric Reliability Council (NERC)"
60	17	"regulation up" should be "regulation up and regulation down"
60	18	"is not included since" should be "is included although"
65	Figure 13	Delete "above FS" in line that begins with "ECON+ ="
76	Figure 15	Add line "REGDOWNC = Regulation down capacity awarded" after line that begins with "REGUPC ="
81	25	"describe" should be "described"
81	26	"described" should be "describe"
82	23	After "reported" insert "forced"
83	3	After "reported" insert "forced"
84	4	After "my" insert "withholding"
103	fn. 52	"p. 77" should be "p. 78"

(Continued)
California Parties' Errata for Exhibit No. CA-5: Prepared Testimony of Robert J. Reynolds, Ph.D. on Behalf of the California Parties

Page	Line	Correction
100	20	After the first sentence of the answer, insert "As stated in the equation, SMAX is equal to supplied output (SO), which I described in Section IV, plus undispatched supplemental energy bid, which is equal to the maximum capacity bid as supplemental energy (MAXSEBID) and the amount actually dispatched (INCSE)."
100	20	"It is" should be "In the absence of regulation and uninstructed deviations, it is simply"

California Parties' Errata for Exhibit No. CA-7: Prepared Testimony of Dr. Carolyn A. Berry on Behalf of the California Parties

Page	Line	Correction
6	5	Question was omitted. Insert, "Q. Please summarize your conclusions." Before line 5.
9	7	"demand" should be "supply"
11	5	"owners" should be footnoted. Insert footnote "Williams did not own but had control of in-state generation."
46	14	"Aug 13" should be "July 31 – August 4"
52	7	Delete "submitted"
56	4-5	Delete the sentence "The following price spike can be seen clearly in the graph of Contra Costa Unit 2."
95	Figure 67, col. labeled "Jun-01"	The 11 instances of "n.a." should be "359.67, 349.84, 333.95, 343.55, 332.11, 341.51, n.a., 523.47, 410.44, 402.51, 514.11"
96	Figure 68, last row	For Jun-01, "0" should be "4,268"
99	Figure 71, last row	For Jun-01, "0" should be "73"
103	5-6	After "June 21," the text in the parentheses "(ISO declared emergency)" should be "(Reliant market manipulation)"
103	6	After "June 22," the text in the parentheses "(ISO declared emergency)" should be "(Reliant market manipulation)"
105	Figure 77	Shading enhanced.

(Continued)
California Parties' Errata for Exhibit No. CA-7: Prepared Testimony of Dr. Carolyn A. Berry on Behalf of the California Parties

Page	Line	Correction
110	14	Delete "for good"
128	Figure 93, last row	For Jun-01, "0" should be "93"

California Parties' Errata for Exhibit No. CA-9: Prepared Testimony of Philip Hanser

Page	Line	Correction
9	fn. 5	"Sellers" should be "sellers"
9	fn. 6	Add "There are analyses that suggest that there was anticompetitive behavior by market participants prior to the period in question. See Exh. No. CA-292."
10	fn. 7	Insert opening parenthesis before "Exh. No. CA-247)"
12	5	"the there" should be "their"
13	8	"… it is written to …" should be "… to whom it is written to …"
13	fn. 19	"CA-283" should be "CA-282"; add "See also Exh. No. CA-181 for another example of similar behavior."
13	fn. 20	Add "See also Exh. No. CA-296 for another example of instructions to misinform the CAISO about a generating unit's status."
21	4	"Seller" should be "seller"
21	18	Insert new footnote "Exh. No. CA-312."
22	fn. 27	"pp. 29-30" should be "pp. 7-8."
23	17	Insert new footnote "Exh. No. CA-306."
24	7	Insert new footnote "Exh. No. CA-315."
24	21	Insert new footnote "Exh. No. CA-308."
25	16	Insert new footnote "Exh. No. CA-307."

(Continued)
California Parties' Errata for Exhibit No. CA-9: Prepared Testimony of Philip Hanser

Page	Line	Correction
26	7	Insert new footnote "Exh. No. CA-316."
26	19	Insert new footnote "Exh. No. CA-310."
27	9	Insert new footnote "Exh. No. CA-310."
28	2	Insert new footnote "Exh. No. CA-309."
28	19	Insert new footnote "Exh. No. CA-314."
31	12	Insert new footnote "Exh. No. CA-311."
32	14-16	Delete the sentence that begins "I also found …".
42	2	"… thus, were almost higher than…" should be "… that were almost always higher than…"
42	fn. 35	Insert page numbers "62,560-62,561"; delete page numbers "pp. 28-31"; insert ¶ between "FERC" and "61,418".
45	fn. 36	Insert page numbers "62,560-62,561"; delete page numbers "pp. 28-31"; insert ¶ between "FERC" and "61,418".

California Parties' Errata for Exhibit No. CA-10: Appendices to Prepared Testimony of Philip Hanser

Page	Line	Correction
20-33	fn. 8	Text of footnote should be "Data request Cal-ISO-4, CAL_ISO_4_Gen_Sch2_xxxx.csv."
20-33	fn. 9	Text of footnote should be "BEEP Stack data from Data request CAL-ISO-1, CAL_ISO_1_Engy_xxxx.csv. : Bids in Operating Reserve markets from Data reques Cal-ISO-4, CAL_ISO_4_Gen_Sch2_xxxx.csv."
34-35	fn. 8	Text of footnote should be "Data request Cal-ISO-4, CAL_ISO_4_Gen_Sch2_xxxx.csv."
34-35	fn. 9	Text of footnote should be "BEEP Stack data from Data request CAL-ISO-1, CAL_ISO_1_Engy_xxxx.csv. : Bids in Operating Reserve markets from Data request Cal-ISO-4, CAL_ISO_4_Gen_Sch2_xxxx.csv."
38	fn. 8	Text of footnote should be "Bid in BEEP Stack and the Hour_Ahead Operating Reserve Markets. : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files. : Bids in operating reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv."
50	¶ 2	"... the second year of 2000" should be "... the second half of 2000"

California Parties' Errata for Exhibit No. CA-11: Prepared Testimony of Richard J. McCann, Ph.D. on Behalf of the California Parties

Page	Line	Correction
33	1	"Exh. Nos. CA-23, CA-24 and CA-26" should be "Exh. Nos. CA-23 and CA-24"
33	4	"that" should be "they"
33	5	"Exh. No. CA-162" should be "Exh. No. CA-295"

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California Parties' Errata for Exhibit No. CA-14: Appendices to the Prepared Testimony of William Green, Manager of Billing and Settlements, California Energy Resources Scheduling Division, California Department of Water Resources on Behalf of the California Parties

Page	Line	Correction
1	3	Under "Max Price," "1,294" should be "793.34"
1	19	Under "Max Price," "793.34" should be "1,101.00"

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California Parties' Errata for Exhibit No. CA-15: Prepared Testimony of Michael J. Harris, Ph.D., Econ One on Behalf of the California Parties

Page	Line	Correction
19	19	"June 20" should be "June 30"
19	21	"June 20" should be "June 30"

California Parties' Errata for Other Exhibits

Exhibit No. CA-329

Page	Line	Correction
1	0002-3	"Tukwila" should be "Aquila"

Exhibit No. CA-330

Page	Line	Correction
1	0002-4	"Tukwila" should be "Aquila"

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Index of Relevant Material Template

Submitter (Party Name)	California Parties
Index Exh. No.	CA-2
Privileged Info (Yes/No)	Yes
Document Title	Appendices to Prepared Testimony of Dr. Peter Fox-Penner on Behalf of the California Parties
Document Author	Dr. Peter Fox-Penner
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	Prices before October 2, 2000 are not consistent with Sellers' market-based rate tariffs and those of the ISO and PX. Prices in the ISO and PX Spot Markets from October 2, 2000 to June 20, 2001 were unjust and unreasonable. Sellers withheld from the market. Sellers generated uninstructed to bypass organized markets. Sellers submitted Bids in the ISO and PX Markets in order to exercise market power. Sellers participated in false load schedules. Sellers participated in Megawatt Laundering or "Ricochet." Sellers participated in "Death Star" or other Congestion Games. Sellers double sold Ancillary Services Capacity. Sellers participated in the "Get Shorty" strategy of selling non-existent Ancillary Services to the ISO. Sellers shared non-public generation outage information. Sellers participated in collusive acts. Sellers' withholding and other market manipulation, not buyer underscheduling, led to forced reliance on the Real-Time Market.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95-000, EL00-98-000 (including all subdockets)
Indicate if Material is New or from the Existing Record (include references to record material)	New
Explanation of what the evidence purports to show	Sellers deliberately and systematically withheld energy from the market, driving up prices by creating false shortages and scarcity. Sellers submitted bids into the PX and ISO energy markets to

	exercise market power. Sellers intentionally submitted false load schedules to increase scarcity and prices in the day-ahead markets and move resources into the real-time markets. Sellers exported power out of California and imported it to sell at inflated prices, creating artificial scarcity and reliability concerns. Sellers shared detailed non-public information regarding competitors' planned and ongoing generation outages. Many market participants, including public power entities, jointly implemented or facilitated Enron-type trading strategies, had and carried out agreements for joint action, and shared competitive market information via trader conversations, industry groups, and information services.
Party/Parties performing any alleged manipulation	Numerous market participants including Sempra, Powerex, Mirant, Dynegy, Reliant, Hafslund Energy, City of Glendale, Williams, Enron, LADWP, Duke Energy, Modesto Irrigation District, City of Redding, City of Glendale, Sacramento Municipal Utility District, Coral Power, and Avista.

* This entry is not limited to the California and Northwest Docket Numbers.

PETER S. FOX-PENNER **Principal and Chairman of the Board**

Peter Fox-Penner is an economist with an engineering education and more than 25 years of experience in regulated industries, energy policy, and environmental issues. In a career that has spanned consulting, senior government service, and academia, he has assisted numerous public and private clients in settings that include expert testimony, publications and speeches, and advice to senior management and boards. He is the author of numerous publications and books and a frequent speaker at conferences and meetings.

Dr. Fox-Penner has a long involvement in utility restructuring economics and policy. He is the author of the *Electric Utility Restructuring: A Guide to The Competitive Era*, a best-selling 1997 work on the subject, and many other publications in electric and energy policy. A former vice president at Charles River Associates, Dr. Fox-Penner joined the U.S. Department of Energy in 1993 as the Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy. He later served as a senior advisor in the White House Office of Science and Technology Policy and an assistant to the Deputy Secretary of Energy.

In 1996, he joined *The Brattle Group* as a Principal and Director of the Washington, DC office. In 2001, he was elected to the position of Chairman of the Board, leading the firm's strategic development efforts.

Dr. Fox-Penner received his B.S. in Electrical Engineering and his M.S. in Mechanical Engineering (Energy Policy) from the University of Illinois, and his Ph.D. in Economics from the Graduate School of Business, University of Chicago.

REPRESENTATIVE EXPERIENCE

Regulated Industries and Electric Restructuring

- Electric utility restructuring
- Performance-based and price cap regulation
- Antitrust, market power, and merger-related issues in regulated industries
- Network and transmission pricing, access rules, and governance
- Utility convergence and retail utility strategic issues
- Economic and policy issues in public interest utility programs
- Load and sales forecasting, pricing, and new product analysis
- Utility telecommunications regulatory issues and strategy

Energy, Environmental, and Technology Policy

- Emissions markets and trading schemes
- Technology and Market Evaluations
- Public Policies Towards New Technologies and R& D
- Energy conservation—economics and policy
- Energy security policies and the strategic petroleum reserve

EMPLOYMENT HISTORY

2001-Present: Chairman, *The Brattle Group*, Washington, DC

1996-Present: Principal and Director, *The Brattle Group*, Washington, DC

1993-1996: Principal Deputy Assistant Secretary for Energy Efficiency and Renewable Energy, United States Department of Energy

Senior Advisor for Technology Policy, Office of Science and Technology Policy, Executive Office of the President

Assistant to the Deputy Secretary of Energy

1989-1993: Vice President, Charles River Associates, Boston, MA

1991-1993: Professorial Lecturer, Center for Energy and Environmental Studies, Boston University

1987-1989: Senior Associate, Charles River Associates

1980-1983: Research Engineer and Chief Research Engineer, Illinois Governor's Office of Consumer Service, Chicago, IL

1977-1980: Research Assistant and Research Engineer, Office of Vice Chancellor for Energy Research, University of Illinois, Urbana, IL

REFEREED PUBLICATIONS

With James Bohn, Romkaew Broehm, and Gary Taylor. "The Regulation of Competition in Wholesale Electric Power Markets." forthcoming Autumn 2002, *Energy Law Journal.*

With Gregory N. Basheda, Darrell B. Chodorow, Jason A. Hicks, Eric Hirst, James K. Mitchell, Dean M. Murphy and Joseph B. Wharton. "The FERC, Stranded Cost Recovery, and Municipalization." *Energy Law Journal* 19 (1998): 351-386

"Efficiency and the Public Interest: QF Transmission and the Energy Policy Act of 1992." *Energy Law Journal* 14 (1993): 51-73.

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With Franklin M. Fisher, Joen Greenwood, William G. Moss, and Almarin Phillips. "Due Diligence and the Demand for Electricity: A Cautionary Tale." *Journal of Industrial Organization, 1992.*

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"Regulating Independent Power Producers: Lessons of the PURPA Approach." *Resources and Energy* 12 (1990): 117-141.

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"Cynics, Martyrs, and the Value of Energy Conservation." *Science and Public Policy* 5 (1978): 105-110.

With Clark Bullard and David Pilati. "Energy Analysis: Handbook for Combining Process and Input-Output Analysis." *Resources and Energy* (June 1979). Also published by the Energy Research and Development Administration, Washington, DC, ERDA 77-61.

"Energy Intensity of Electric Commuter Railways." Center for Advanced Computation Technical Memo 24, June 1974. Reprinted as "Total Energy and Labor Requirements for an Electric Commuter Railroad." *Energy* 3 (1978): 539-542.

MONOGRAPHS AND BOOKS

With Karen Palmer, David Simpson, and Michael Toman. "Power Plant Fuel Supply Contracts: The Changing Nature of the Long-Term Supply Relationship." Arlington, VA: Public Utility Reports, 1992.

Electric Power Transmission and Wheeling: A Technical Primer. Washington, DC: The Edison Electric Institute, 1990.

Electric Utility Restructuring: A Guide to the Competitive Era. Vienna, VA: Public Utility Reports, 1997

BOOK CHAPTERS

With Romkaew Broehm. "Price-Responsive Electric Demand: *A National Necessity, Not an Option,*" forthcoming in *Towards Market Based Pricing of Electricity*, Faruqui Ahmad, ed. 2002.

With Ellen Craig and Adam Schumacher. "Value Drivers in the Utility Industry of 2002." Forthcoming *PUR Analysis of The Nation's Largest Investor-Owned Electric and Gas Utilities*, 2001 Edition, Public Utilities Reports.

"Energy Policy: Today's View from the Federal Government," in *The Energy Crisis: Unresolved Issues and Enduring Legacies*, David Feldman, ed., Johns Hopkins University Press, 1996.

"What Role Should the Federal Government Play in Energy Efficiency?" in *Policy Evolution: Energy Conservation to Energy Efficiency.* Douglas A. Decker and Alan Berolzheimer, eds. Liburn, GA: The Fairmount Press, 1997.

SELECTED ADDITIONAL PUBLICATIONS

"Easing Gridlock on the Grid: Electric Planning and Siting Compacts."*The Electricity Journal, November* 2001.

"Clean Growth: A Balanced Energy Policy for the 21st Century." Progressive Policy Institute's Policy Report, October 2001.

With Greg Basheda. "A Short Honeymoon for Utility Deregulation." *Issues in Science and Technology*, Spring 2001.

"What not to learn from the Calif. crisis." (Op-ed) *The Providence Journal*, March 3, 2001.

"Epitaph for Electric Deregulation." Prepared for the National Council on Competition and the Electric Industry, December 2000 meeting, October 2000.

With Frank Graves. "Monopoly Power After Reform? A Time for Soul-Searching." *Public Utilities Fortnightly*, May 2000.

"Federal Restructuring Legislation: Any Chance in This Congressional Session?" *Energy Efficiency Journal*, March 2000.

"Electric Power Deregulation: Blessings and Blemishes, A Non-Technical Review of the Issues Associated with Competition in Today's Electric Power Industry." Prepared for the National Council on Competition and the Electric Industry, March 14, 2000.

With Johannes P. Pfeifenberger. "Transmission Access, Episode II: FERC's Journey." *Public Utilities Fortnightly*, August 1999.

With J.P. Pfeifenberger, P.Q Hanser, and G.N. Basheda. "In What Shape is Your ISO?" *The Electricity Journal*, July 1998.

"Transco vs. ISO: A Sideshow?" *Public Utilities Fortnightly*, June 1, 1998.

With Matt O'Loughlin. "Fostering Market Center Development and Integration of the Natural Gas Grid Through Improved Pipeline Ratemaking." Prepared for NorAm Gas Transmission Company, May 1998.

"An Open Letter to the President" *The Electricity Journal*, March 1997.

With Philip Q Hanser and Joseph B. Wharton. "Real-Time Pricing: Restructuring's Big Bang?" *Public Utilities Fortnightly*, March 1997.

"Critical Trends in State Utility Regulation." *Natural Resources and Environment* 8 (Winter 1994): 17-20.

"Electricity in A Competitive Environment: The Real Issue is Not Retail Wheeling." *Edison Times IRP Quarterly*, Fall 1994.

With Chris Fitzgerald. "A Proposal for Design-Based Auto Industry Environmental Regulation." *Total Quality Environmental Management* 2 (Spring 1993): 323-327.

"The Private DSM Industry - A Gleam in Whose Eye?" *The Electricity Journal* 4 (December 1991): 21-25.

With Paul D. O'Rourke and Peter J. Spinney. *Competitive Procurement of Electric Utility Resources* (EPRI CU-6898s). Palo Alto, CA: Electric Power Research Institute, July 1990.

With Mark Horton and Peter Spinney. "Bidding Update." *Cogeneration & Resource Recovery* 9, no. 7 (November/December 1990): 6–11.

With Edward Kee. "Bid Policies Overhauled." *Cogeneration & Resource Recovery* 9, no. 7 (November/December 1990): 14–15.

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"Price Formula Issues Associated with SPR Release Programs." Prepared for the Office of Energy Emergencies, U.S. Department of Energy, 1988.

"The Immediate Consequences of an Oil Supply Emergency for the Financial Markets and Major User Groups." Prepared for the Office of Energy Emergencies, U.S. Department of Energy, 1988.

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"The Norwegian Power Planning Process." Institute for Environmental Studies, University of Oslo, Norway, 1981.

With R. Herendeen.. "A 1972 Energy and Labor Commodity-Commodity Input-Output Model." Energy Research Group, University of Illinois, Urbana, IL, March 1980.

"Correspondence Between the EDIO Input-Output Model and the ERG-90 and 360-Order Input-Output Model." Energy Research Group, University of Illinois, Urbana, IL, March 1980.

With J. Kurish. "Energy and Labor Cost of Alternative Coal-Electric Fuel Cycles." Energy Research Group, University of Illinois, Urbana, IL, February 1980.

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"A Structure of the Electric Utility Industry, 1990." Energy Research Group Technical Memo 121, November 1979.

With B. Hannon and R. Herendeen. "Calculation of Alpha in the Determination of Primary Energy." Energy Research Group, University of Illinois, Urbana, IL, November 1979.

"Notes of the Bechtel ESPM/ERG I/O Bridge for Operating (Annual) and Capital (Investment) Costs, Purchasers Prices, 1978." Energy Research Group Technical Memo 119, August 1979.

"Transformation of Brookhaven National Laboratories 110-Order I/O Data into ERG-Usable Form." Energy Research Group Technical Memo 118, July 1979.

"1967-1977 Price Indices for Use with the Energy Research Group Energy Input-Output Policy Models." Energy Research Group Technical Memo 117, June 1979.

"Direct Energy Transactions Matrix for 1971." Energy Research Group, University of Illinois, Urbana, IL, June 1979.

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"Standardization of Energy Accounting Techniques." Center for Advanced Computation Technical Memo 83, January 1977.

With Jaap Spek. "Stockpile Optimization and Versatility Consideration for Strategic and Critical Materials." Center for Advanced Computation Document 217, May 1976.

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"The Dollar, Energy and Labor Impact of 1971 Regular Route Intercity Bus Transportation." Center for Advanced Computation Technical Memo 31, July 1974.

"Energy Intensity of Motorcycle Travel." Center for Advanced Computation Technical Memo 30, July 1974.

SELECTED CONFERENCE/WORKSHOP PARTICIPATION

"Enron and Electricity Deregulation." Presented at Le Centre Francais sure les Etats-Unis (CFE), May 15, 2002.

"At the Crossroads or on the Brink? U.S. Electric Industry Trends in Early 2002." Presented at Cooperative Finance Corporation's CEO Conference, April 10, 2002;

"Revenues, Regulations and ITC Business Models," Presented at the Executive Transmission Forum, January 29, 2002.

"A 'Securities' Versus 'Antitrust' of the Competitive Power Industry and its Implication for RTO Market Monitoring." Remarks before the American Antitrust Institute Conference on Electricity Market Monitoring, December 11, 2001.

"What Does the California Experience Tell Us About Fixing the Rest of America's Power Markets?" By Peter Fox-Penner and Joseph B. Wharton. Presented at the National Association Business Economics Regional/Utility Roundtable, April 24, 2001.

"Taming the Lions in America's Electric Markets: Five Major Challenge." Presented at National Governors' Association Center for Best Practices, Executive Policy Forum on Energy, "*Is Electricity Restructuring in Jeopardy?*" Washington, DC, April 5, 2001.

"The Challenge to Co-operatives in the Electric Power Industry of the 21st Century." NRECA's 30th Annual CEO Leadership Conference. Keystone, CO, August 2, 2000.

"Price-Responsive Electric Demand: A National Priority." The Electric Power Research Institute's International Energy Pricing Conference. Washington, DC, July 26, 2000.

"Incentives, Regulation and Transmission Companies: One Practioner's View." Presented to The Federal Energy Regulatory Commission's RTO Staff. Washington, DC, July 16, 1999.

"ISOs, Transcos, Gridcos, and Long-Run Power Industry Efficiency." Federal Energy Bar Association's Mid-Year Meeting. Washington, DC, December 4, 1998.

"Market Power Issues in Restructured Electric Power Markets." American Bar Association's Satellite Seminar, "Critical Federal and State Practice Issues in Electricity Deregulation." Washington, DC, December 3, 1998

"SAVIOR OR BUREAUCRAT? ISOs, Competition, and Independent Transmission Companies." Winning with Retail Competition, 2nd Annual PUR Conference, Arlington, VA, June 22, 1998.

"The Evolution of the Energy Services Industry." *Have it Your Way: Buying and Saving Energy in the Age of Customer Choice*, Annual Meeting of Energy Management Consortium and the Northeast Energy Efficiency Council, Boston, MA, September 18, 1997.

"Volatility and Stability in the Deregulated Generation Marketplace." Restructuring and Convergence, Successful Strategies in the Energy Services Marketplace, Arlington, VA, May 22, 1997.

"Progress and Promise: The Clinton Administration's Efforts in Fostering Sustainable Development." Global Accords for Sustainable Development: Enabling Technologies and Links to Finance and Legal Institutions Conference, M.I.T., Cambridge, MA, September 5, 1996.

Invited Speaker, Fourth Biennial Conference of the International Society for Ecological Economics, Boston, MA, August 7, 1996.

"Linking Energy, Environment, and Technology to the Economy." Globalcon Energy and Environment Exposition, April 3, 1996.

21st Annual Illinois Energy Conference, November 1996.

Civil Engineering Research Foundation, Washington meeting, October 12, 1995.

"Technology and Economic Growth: The Government's Role." M.I.T. Club of Washington, DC, October 10, 1995.

"The Impact of Government Budget Changes and Restructuring on Engineering." ASME and the Public Lecture Series, Washington, DC, September 21, 1995.

"Energy - Environment - Technology: Two Visions, Two Directions." *Proceedings of the 1995 International Energy and Environment Congress.* Association of Energy Engineers, Richmond, VA, 1995.

"The Federal Role in Energy Efficiency." Eighth Biannual DSM Evaluation Conference, Chicago, IL, August 24, 1995.

Invited Speaker, Seventh National DOE/EPRI Demand-Side Management Conference, Dallas, TX, June 28, 1995.

"Utility Restructuring and Regulatory Reform." Invited Presentation, National Association of Regulatory Utility Commissioners Attorneys' Conference, Tucson, AZ, May 18, 1995.

Invited Speaker, Conservation Committee, Semi-Annual Meetings of the National Association of Regulatory Utility Commissioners, 1994 and 1995.

Invited Panelist, OECD Seminar on Sustainable Production and Consumption, Massachusetts Institute of Technology, December 19, 1994.

"Electric Utilities and the Environment: Restructuring Need Not Mean Retreat." Invited Presentation, "Brave New World - Managing Externalities in a Competitive Electric Utility Industry." University of Illinois Center for Regulatory Studies, Chicago, IL, November 17, 1994.

Invited Speaker, International Ground Source Heat Pump Association, Hershey, PA, October 17, 1994.

Invited Speaker, "Washington: Business and Public Policy," Brookings Institution Seminar, October 18, 1994.

"Federal Climate Change Management Programs and Climate-Wise," Businesses for Social Responsibility 1994 Environment Conference, Boston, MA, October 13, 1994.

Invited Speaker, National Association of State Energy Officials, Asheville, NC, August 31, 1984.

Invited Speaker, Annual Meeting of the California Institute for Energy Efficiency, Berkeley, CA, July 25, 1994.

"Voluntary Greenhouse Gas Reporting Under the Energy Policy Act of 1992." Invited Presentation, International Conference on Global Climate Change, Center for Environmental Information, Washington, DC, February 1993.

Panel Moderator, Natural Gas Procurement Strategies, Association of Energy Engineers Annual Conference, Boston, MA, June1992.

Panel Moderator, Alternative Fuel Vehicles Conference, the Management Exchange, Washington, DC, April 1992.

Invited Presenter, American Water Works Association. Conservation Committee Workshop, Austin, TX, January 1992.

"The Future History of DSM." Plenary presentation, 5th National Demand-Side Management Conference, Boston, MA, August 1, 1991.

"Visibility of the Buy Strategy — Bulk Power Transfers: Solution or Fatal Attraction?" The Management Exchange "The Buy vs. Build Decision" Conference, Washington, DC, March 22,1991.

BOARDS AND OTHER PROFESSIONAL ACTIVITIES

Member of the Board, Global Energy Group, 2002 -

Co-Founder and Steering Committee Chair, Patriot's Energy Pledge 2001 -

Advisor, Progressive Policy Institute, Washington, DC, 2000 - Present

Advisor Center for National Policy, Washington, DC, 1993-present

Advisory Board, Massachusetts Institute of Technology Energy Laboratory, 1993-1996

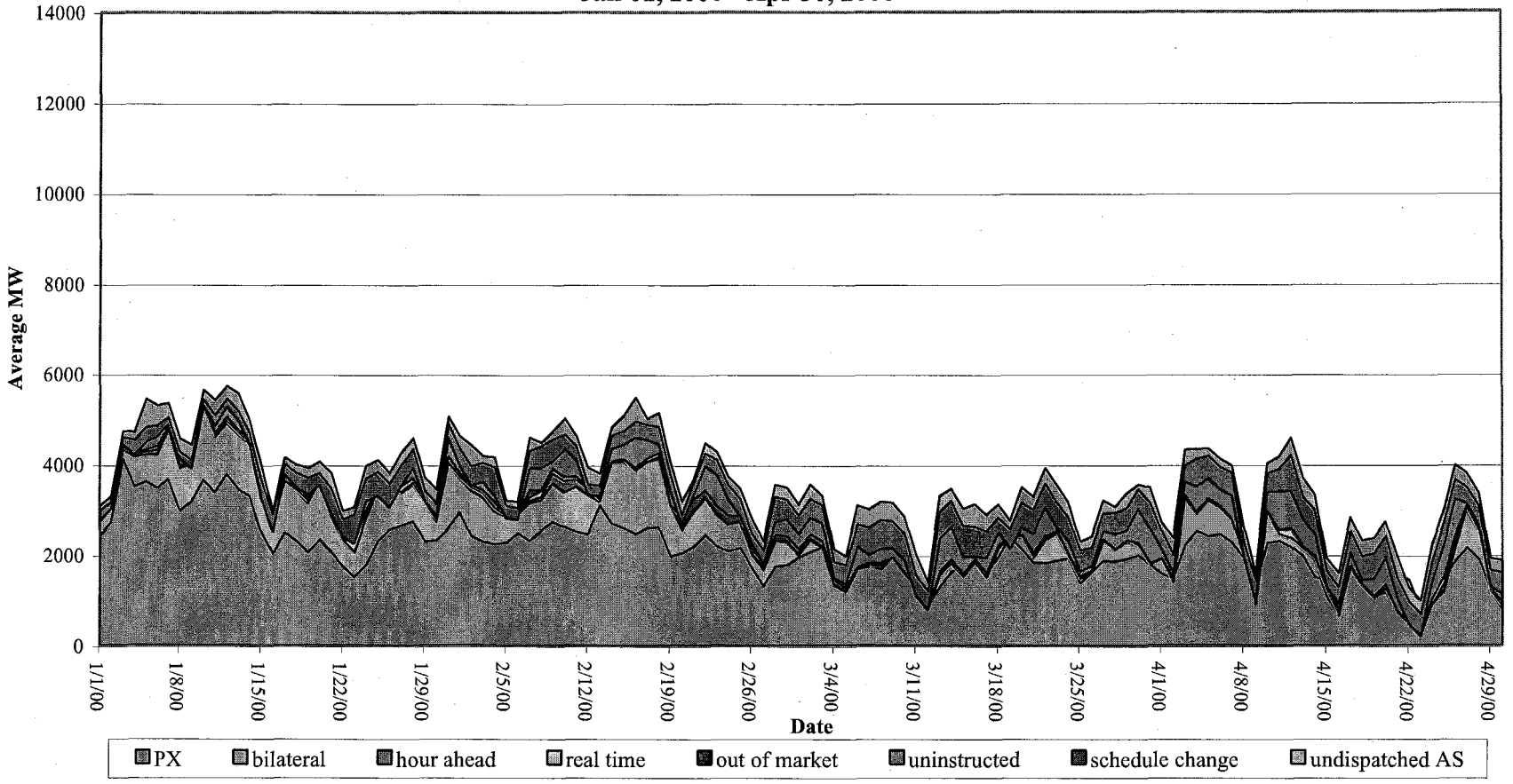
Nominator, Heniz Foundation Awards, 1995-1996

Member, Illinois Solar Energy Advisory Board, 1980

HONORS AND AWARDS

Who's Who in the East (1991, 1992)
Fellow, Center for the Study of Economy and the State, University of Chicago, 1986
NSF Travel Fellow, Dec. 1981
MIT Institute Fellowship, 1978
Earle C. Anthony Fellowship, 1978
Union Carbide Fellow, 1977-78
Michigan Annual Giving Scholarship, 1976
Illinois State Scholar, 1976
National Merit Scholar, 1976
Sigma Tau Beta
Phi Kappa Phi
Eta Kappa Nu

Figure B-1a
Average Megawatts Sold by California Generators (All Hours)
Big Five
Jan 01, 2000 - Apr 30, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

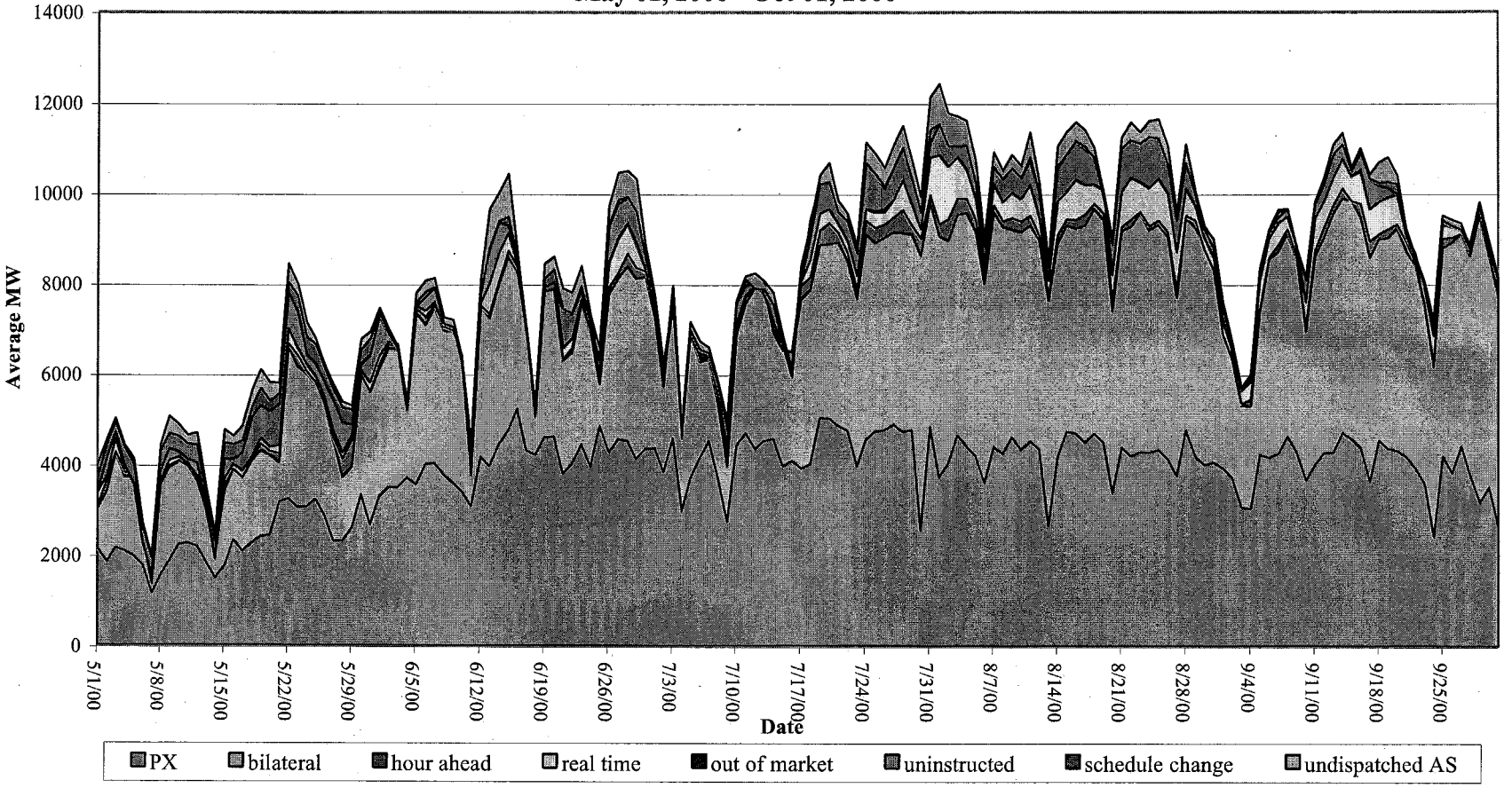
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

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Figure B-1b
Average Megawatts Sold by California Generators (All Hours)
Big Five
May 01, 2000 - Oct 01, 2000



Notes & Sources:

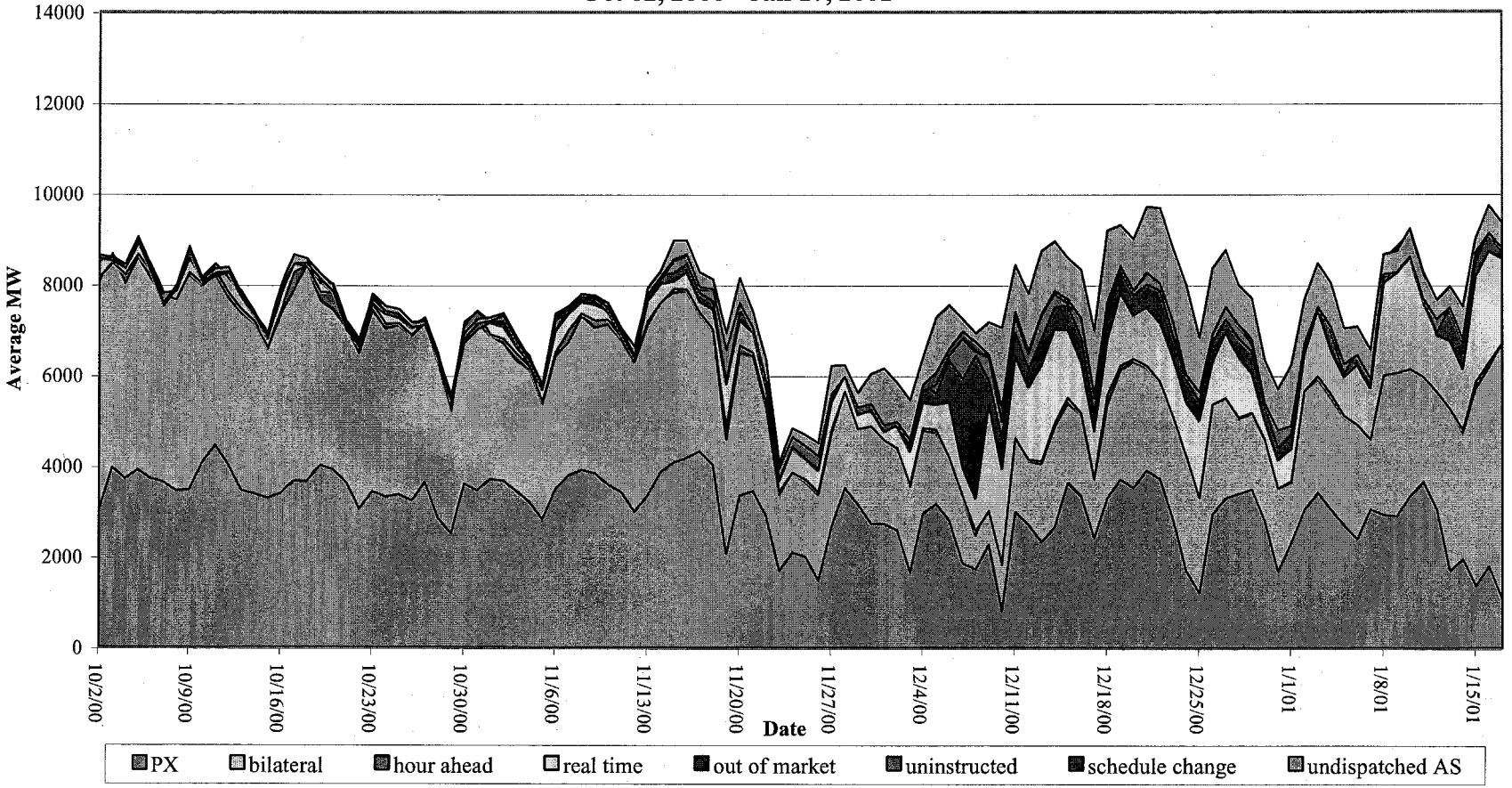
[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure B-1c
Average Megawatts Sold by California Generators (All Hours)
Big Five
Oct 02, 2000 - Jan 17, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

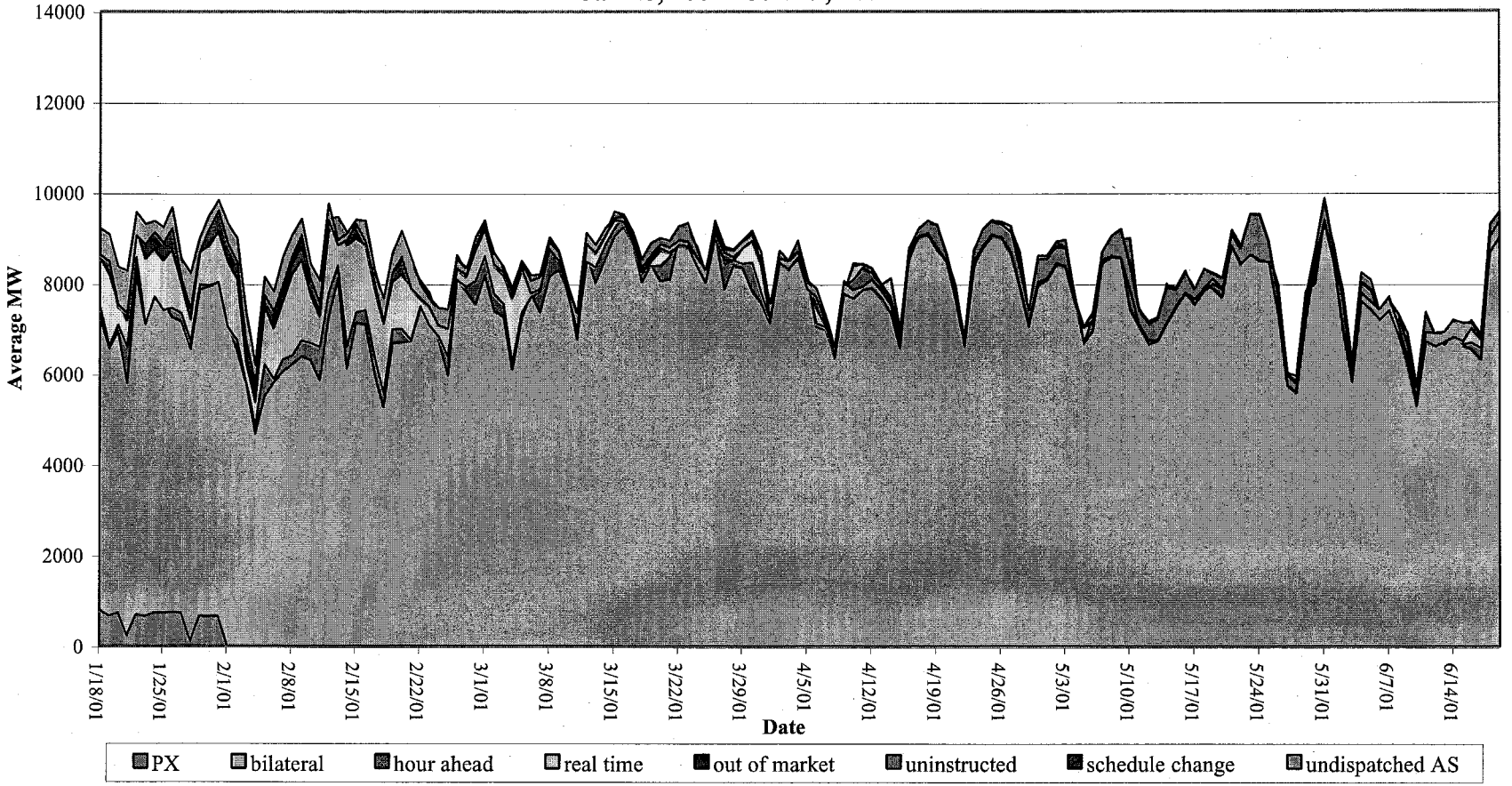
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

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Not Available to Competitive Duty Personnel

Figure B-1d
Average Megawatts Sold by California Generators (All Hours)
Big Five
Jan 18, 2001 - Jun 19, 2001



Notes & Sources:

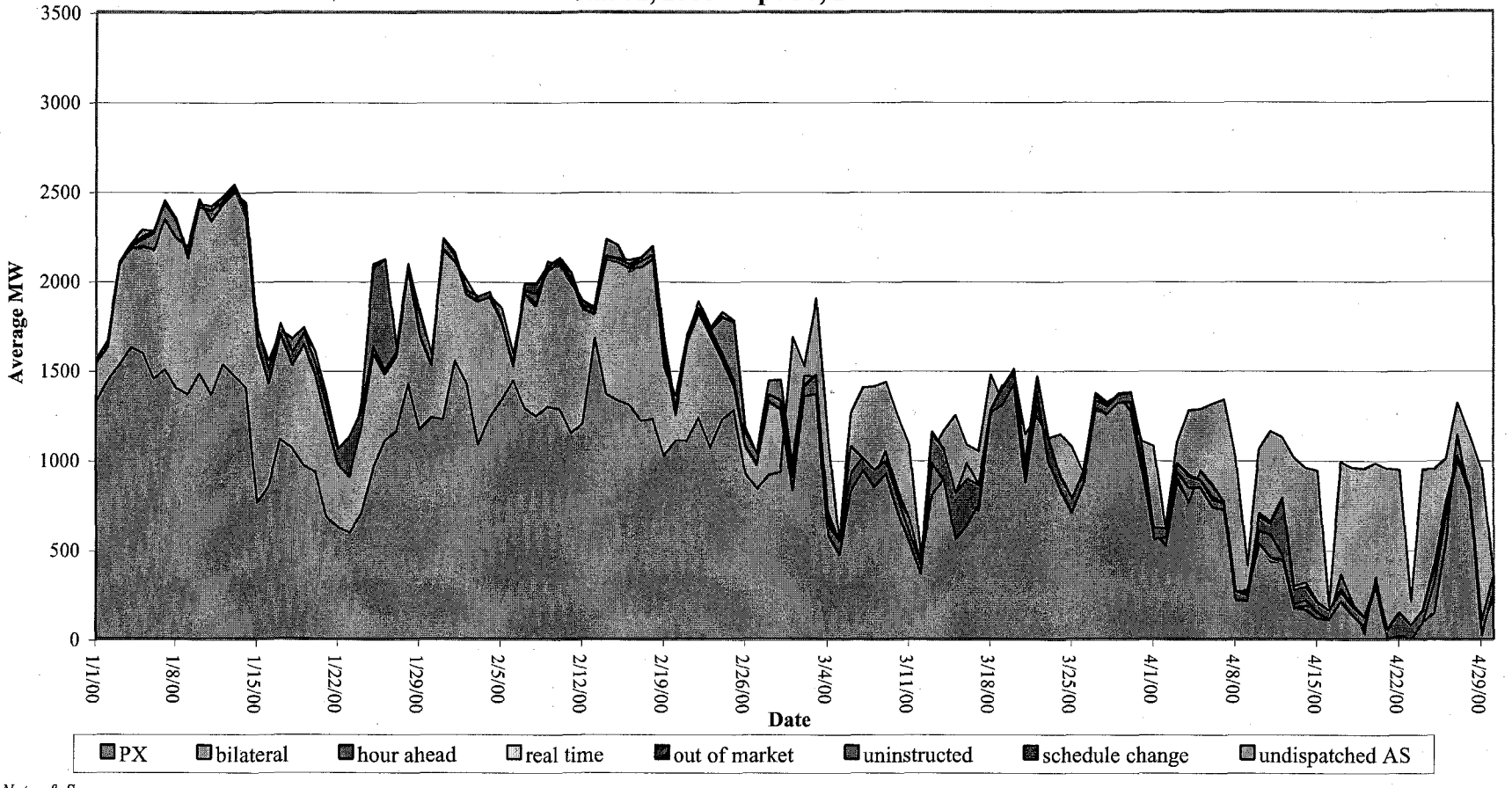
[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure B-2a
Average Megawatts Sold by California Generators (All Hours)
Duke Energy Trading and Marketing, L.L.C.
Jan 01, 2000 - Apr 30, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

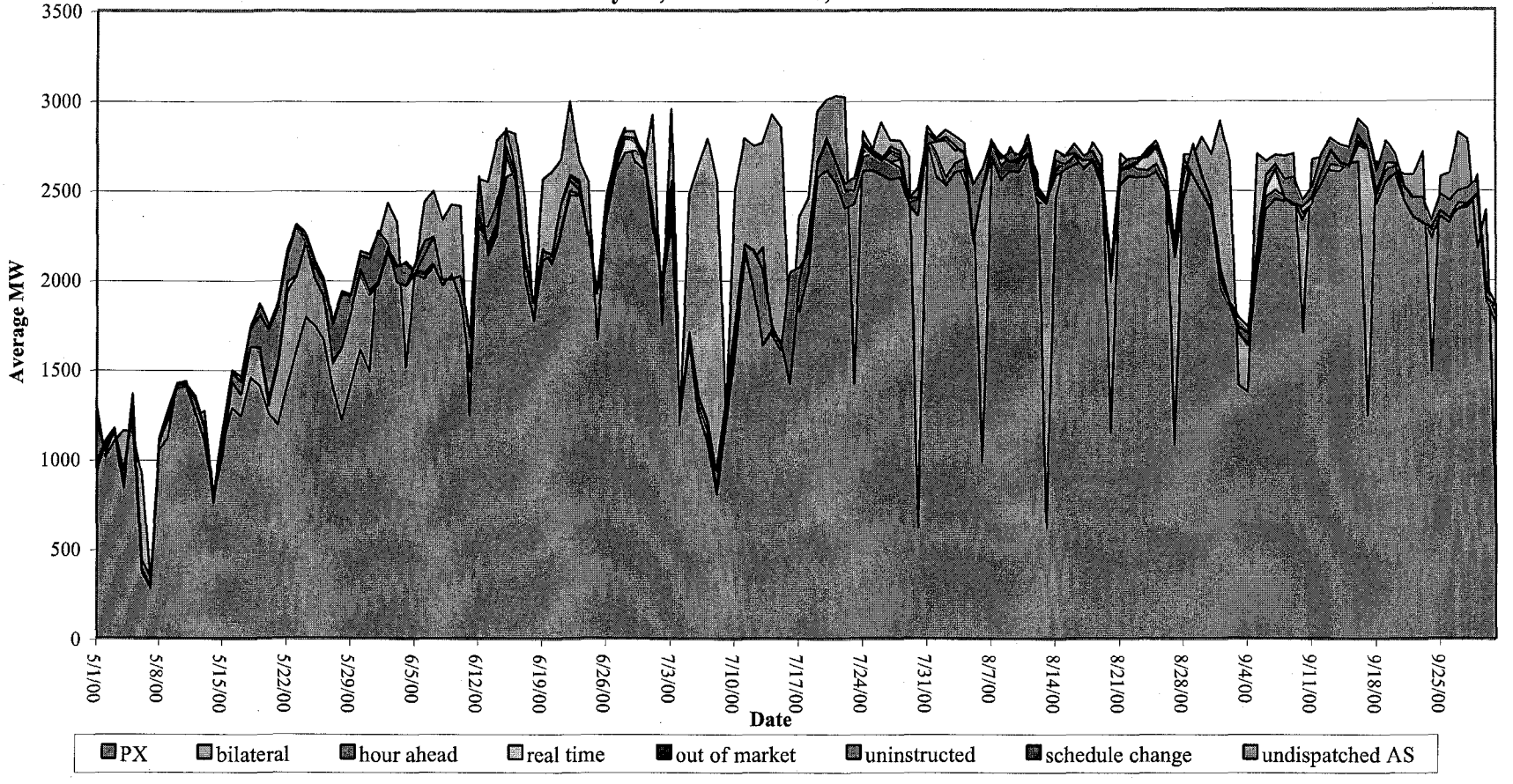
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-2b
Average Megawatts Sold by California Generators (All Hours)
Duke Energy Trading and Marketing, L.L.C.
May 01, 2000 - Oct 01, 2000



Notes & Sources:

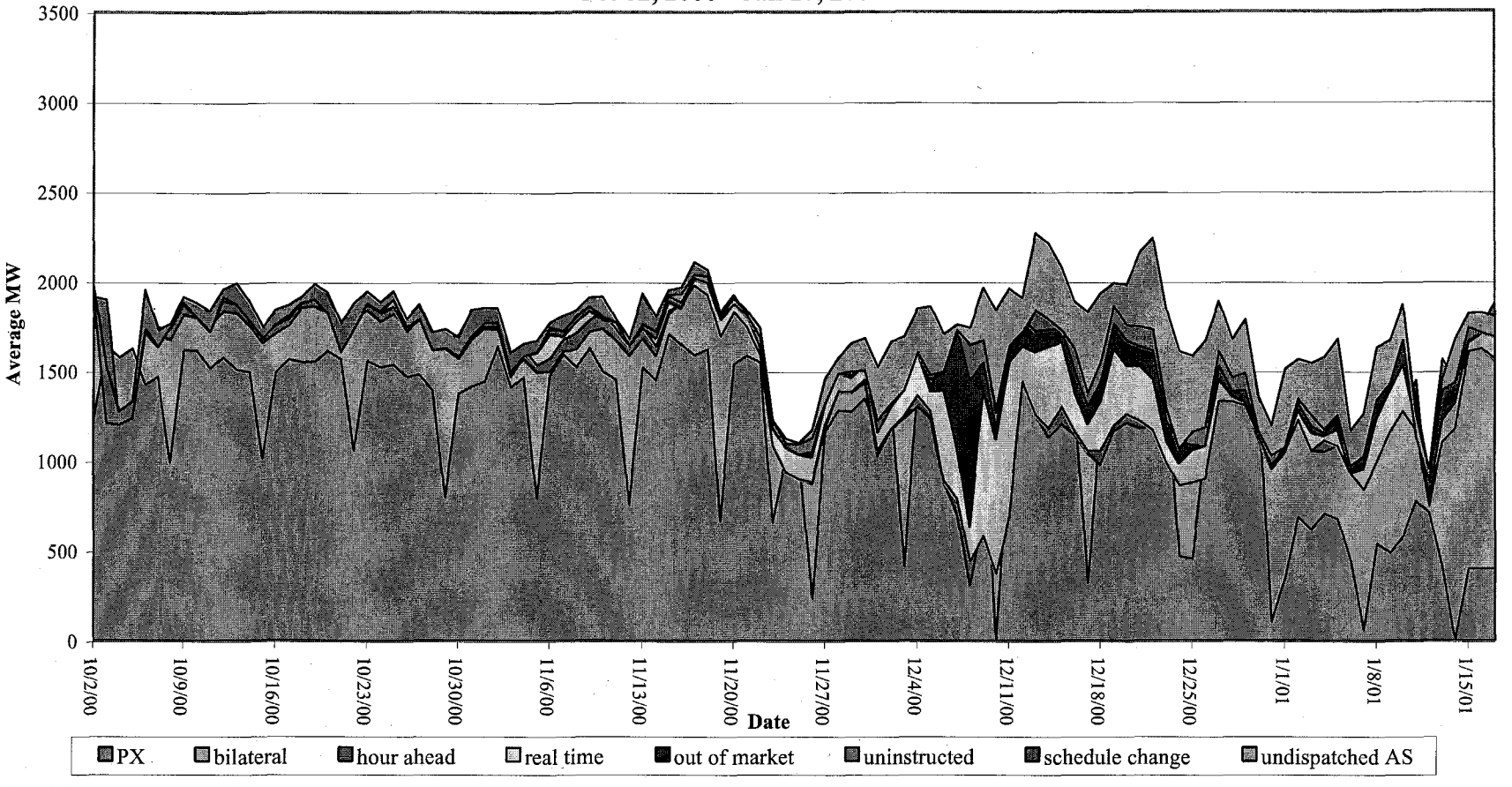
[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure B-2c
Average Megawatts Sold by California Generators (All Hours)
Duke Energy Trading and Marketing, L.L.C.
Oct 02, 2000 - Jan 17, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

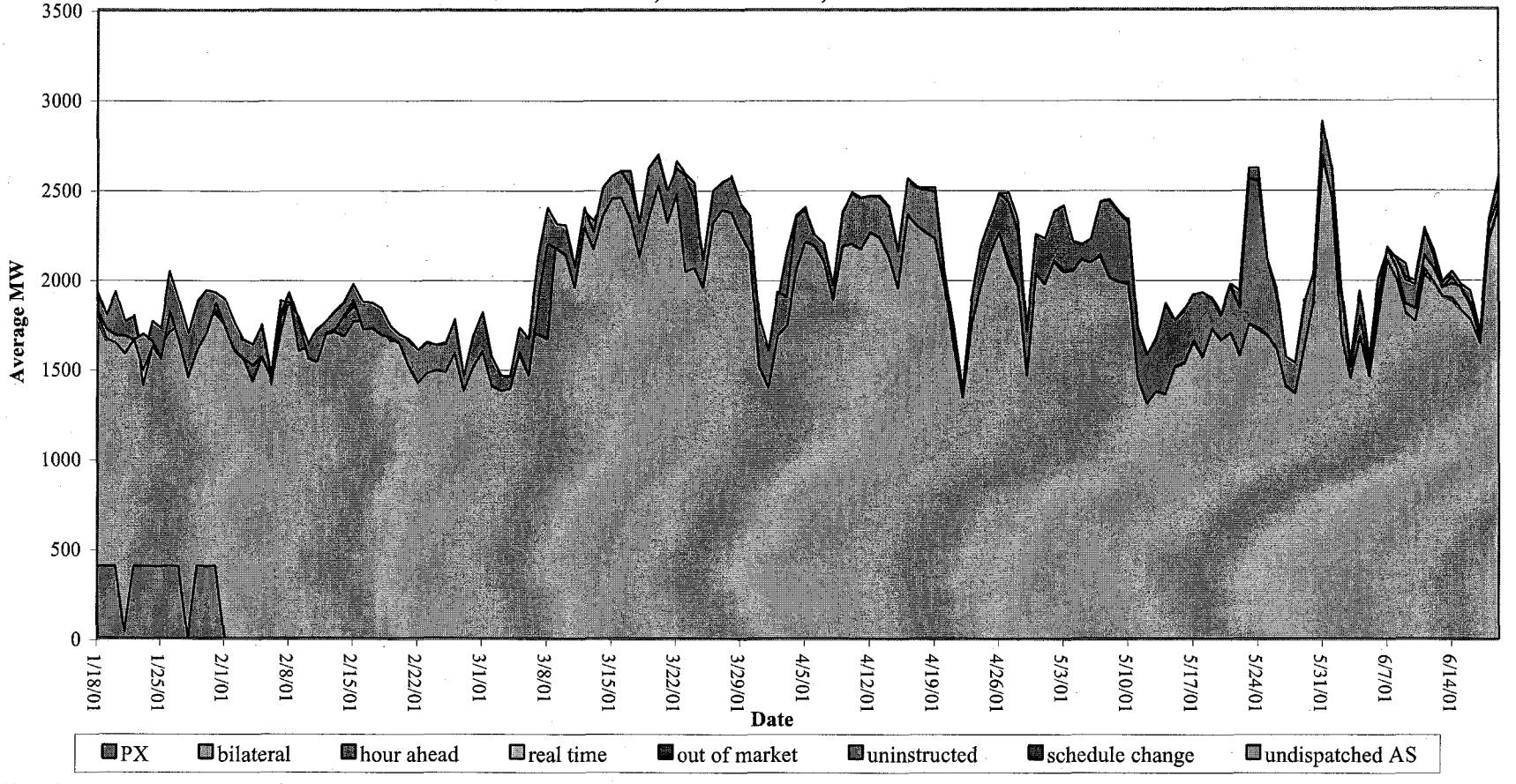
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-2d
Average Megawatts Sold by California Generators (All Hours)
Duke Energy Trading and Marketing, L.L.C.
Jan 18, 2001 - Jun 19, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

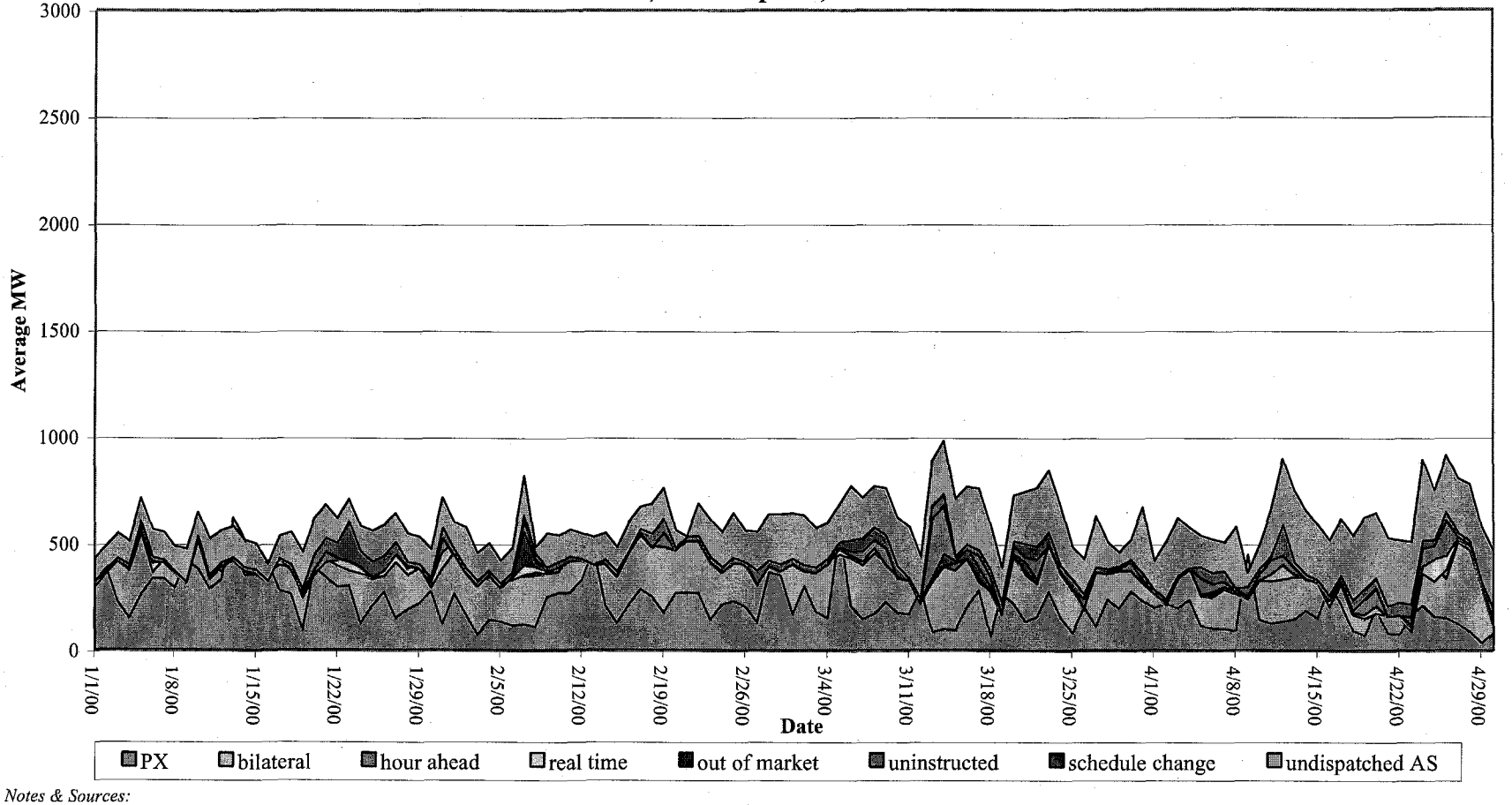
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-3a
Average Megawatts Sold by California Generators (All Hours)
Dynegy/Electric Clearinghouse
Jan 01, 2000 - Apr 30, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

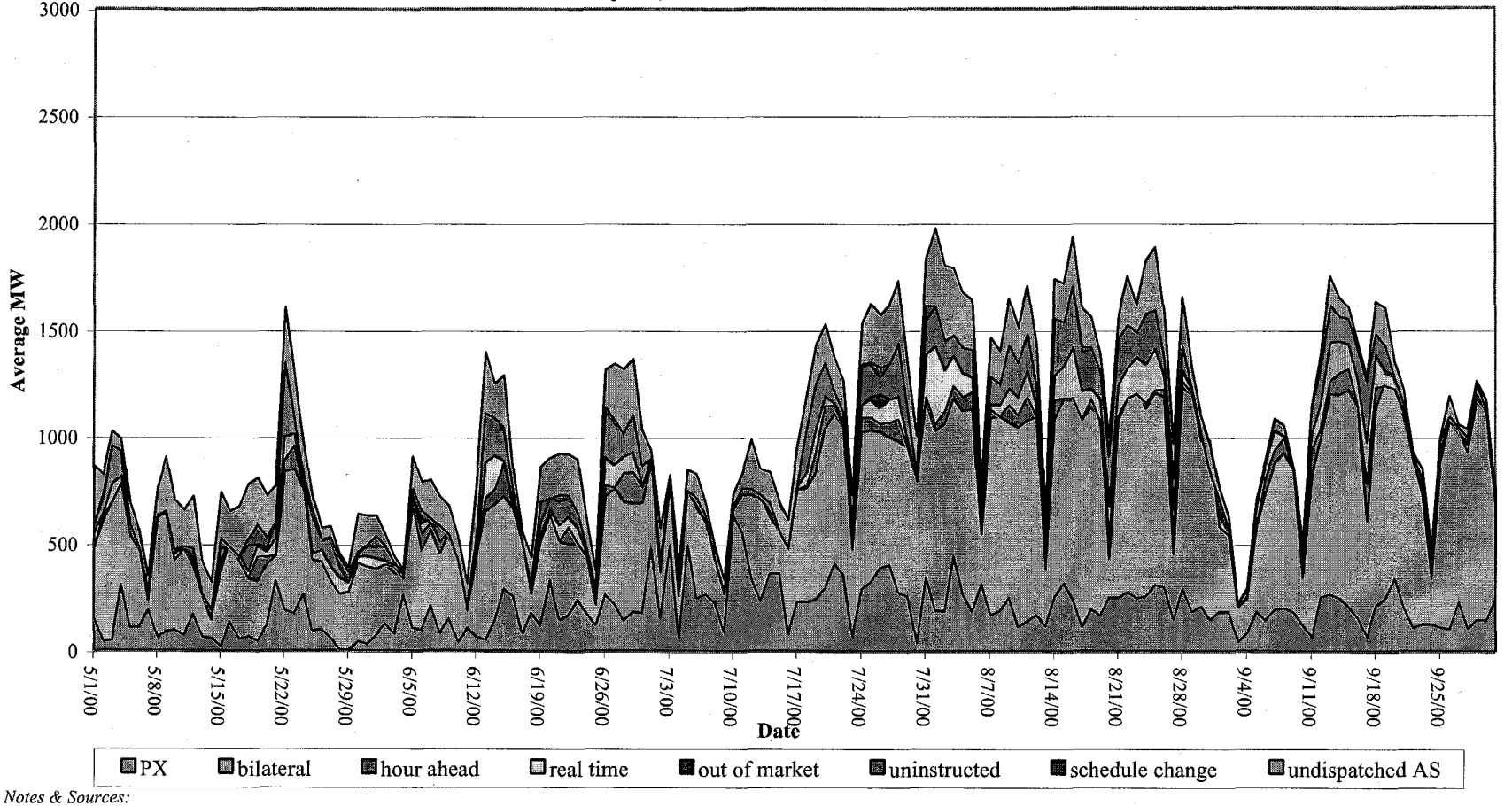
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-3b
Average Megawatts Sold by California Generators (All Hours)
Dynegy/Electric Clearinghouse
May 01, 2000 - Oct 01, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

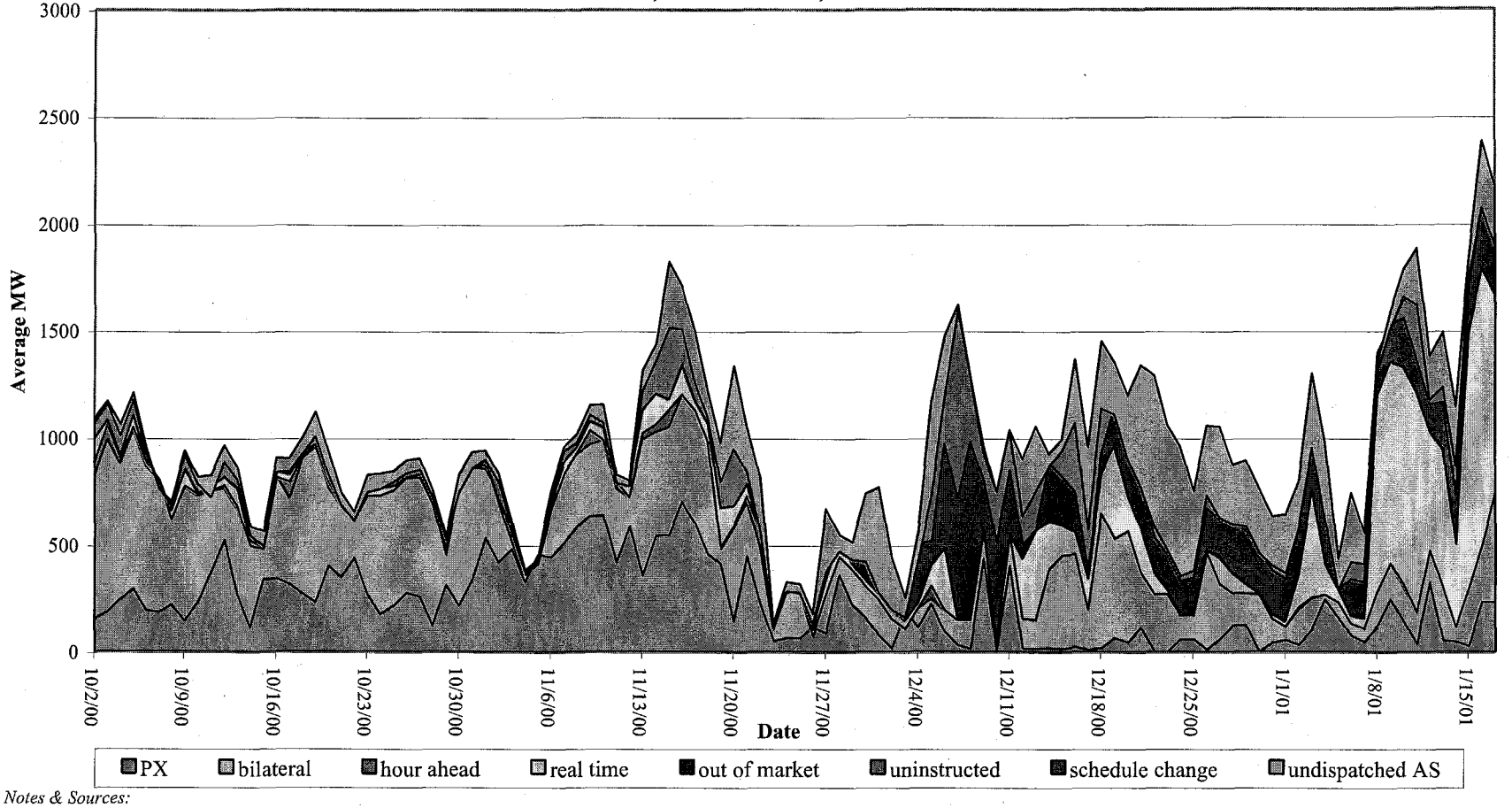
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-3c
Average Megawatts Sold by California Generators (All Hours)
Dynegy/Electric Clearinghouse
Oct 02, 2000 - Jan 17, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

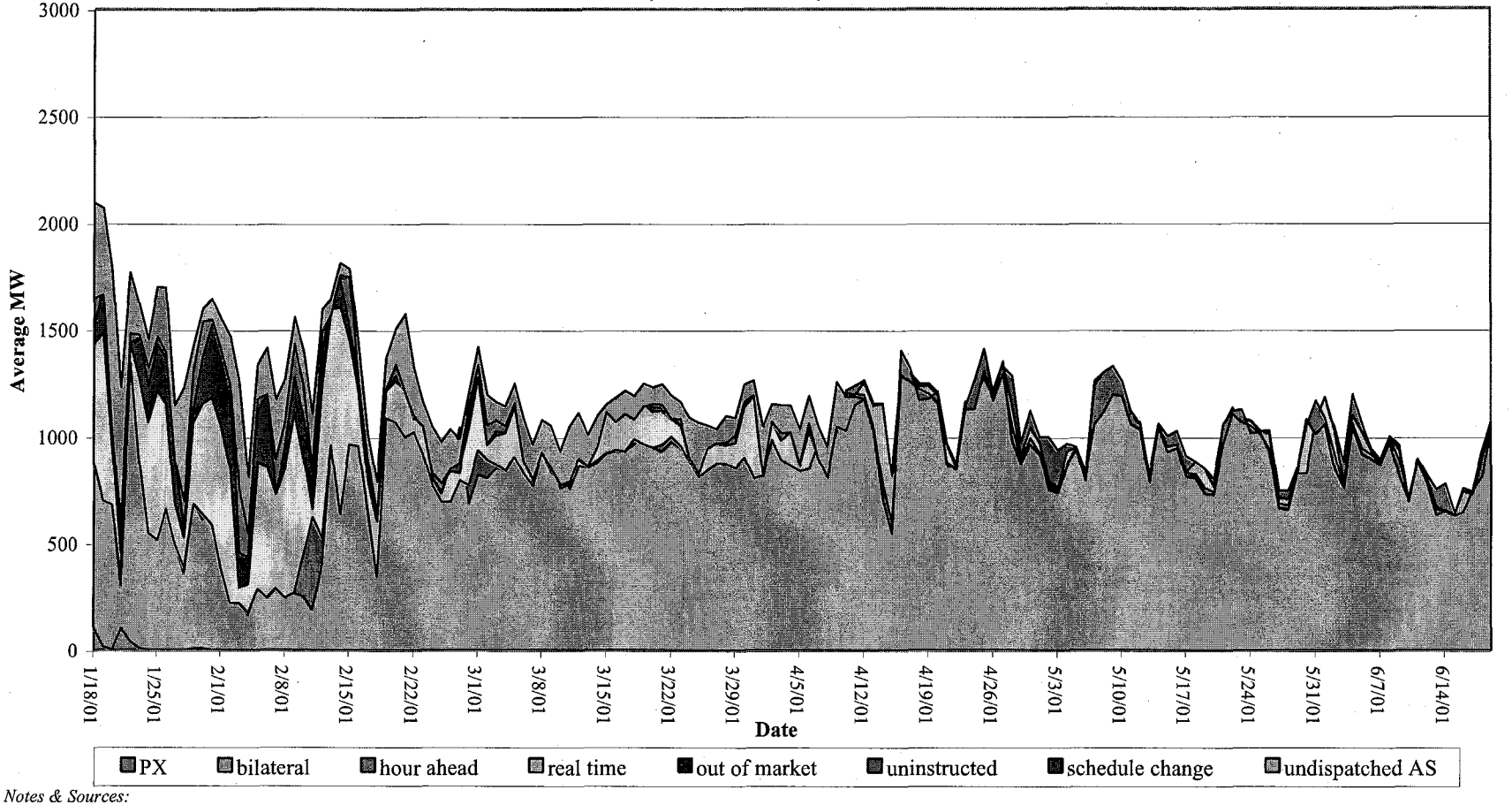
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-3d
Average Megawatts Sold by California Generators (All Hours)
Dynegy/Electric Clearinghouse
Jan 18, 2001 - Jun 19, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

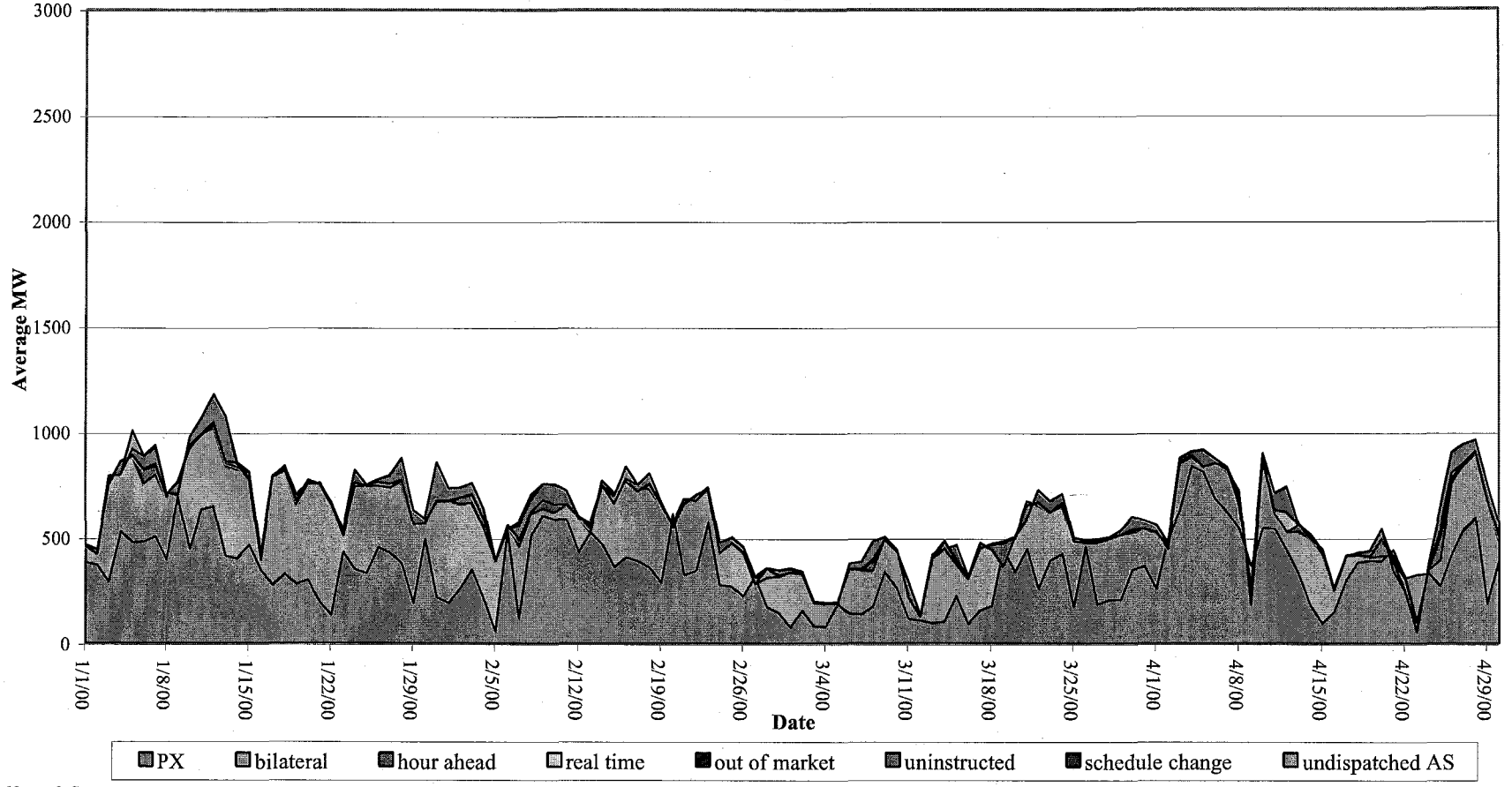
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-4a
Average Megawatts Sold by California Generators (All Hours)
Reliant Energy Services, Inc.
Jan 01, 2000 - Apr 30, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

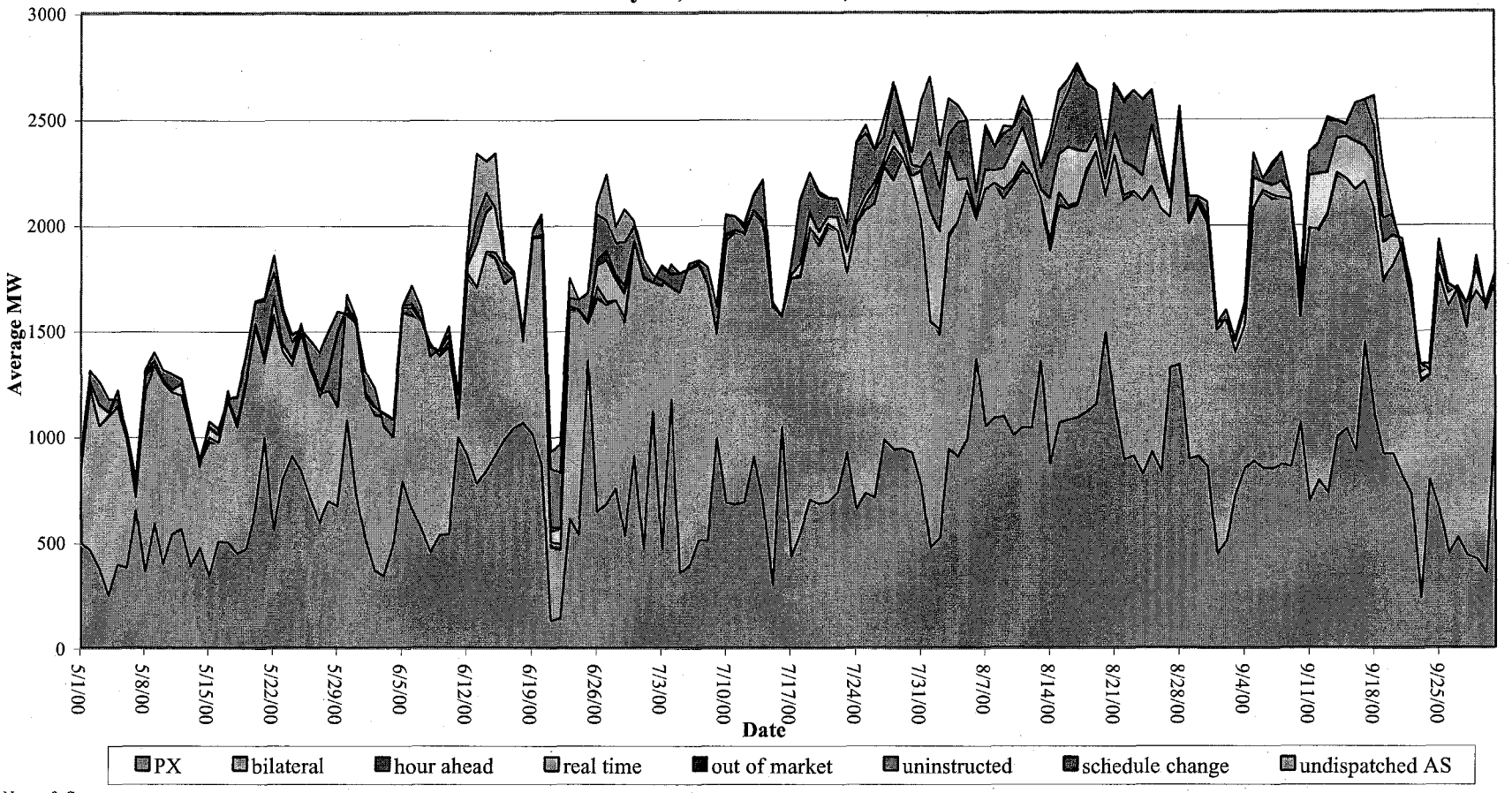
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-4b
Average Megawatts Sold by California Generators (All Hours)
Reliant Energy Services, Inc.
May 01, 2000 - Oct 01, 2000



Notes & Sources:

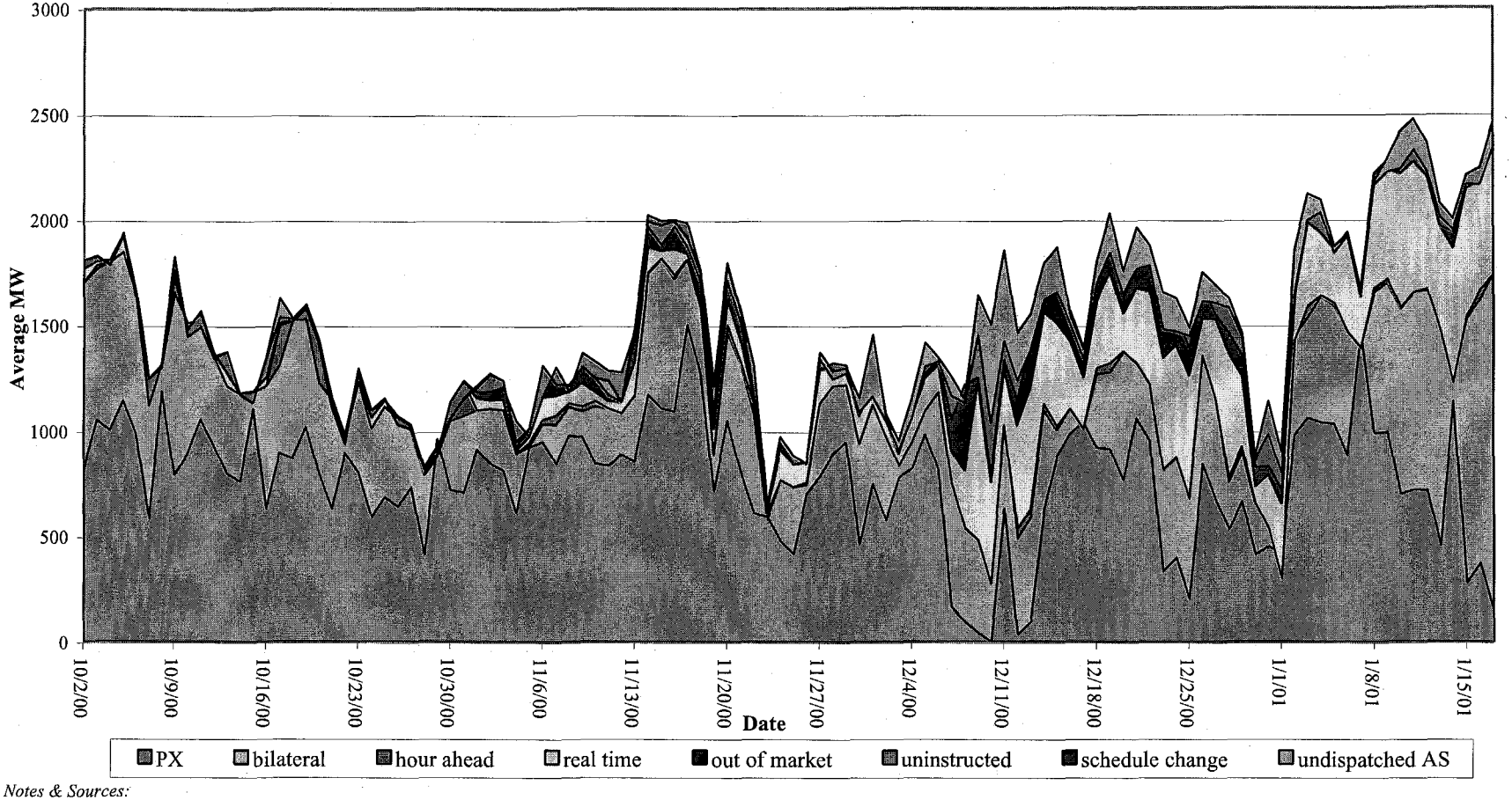
[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure B-4c
Average Megawatts Sold by California Generators (All Hours)
Reliant Energy Services, Inc.
Oct 02, 2000 - Jan 17, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

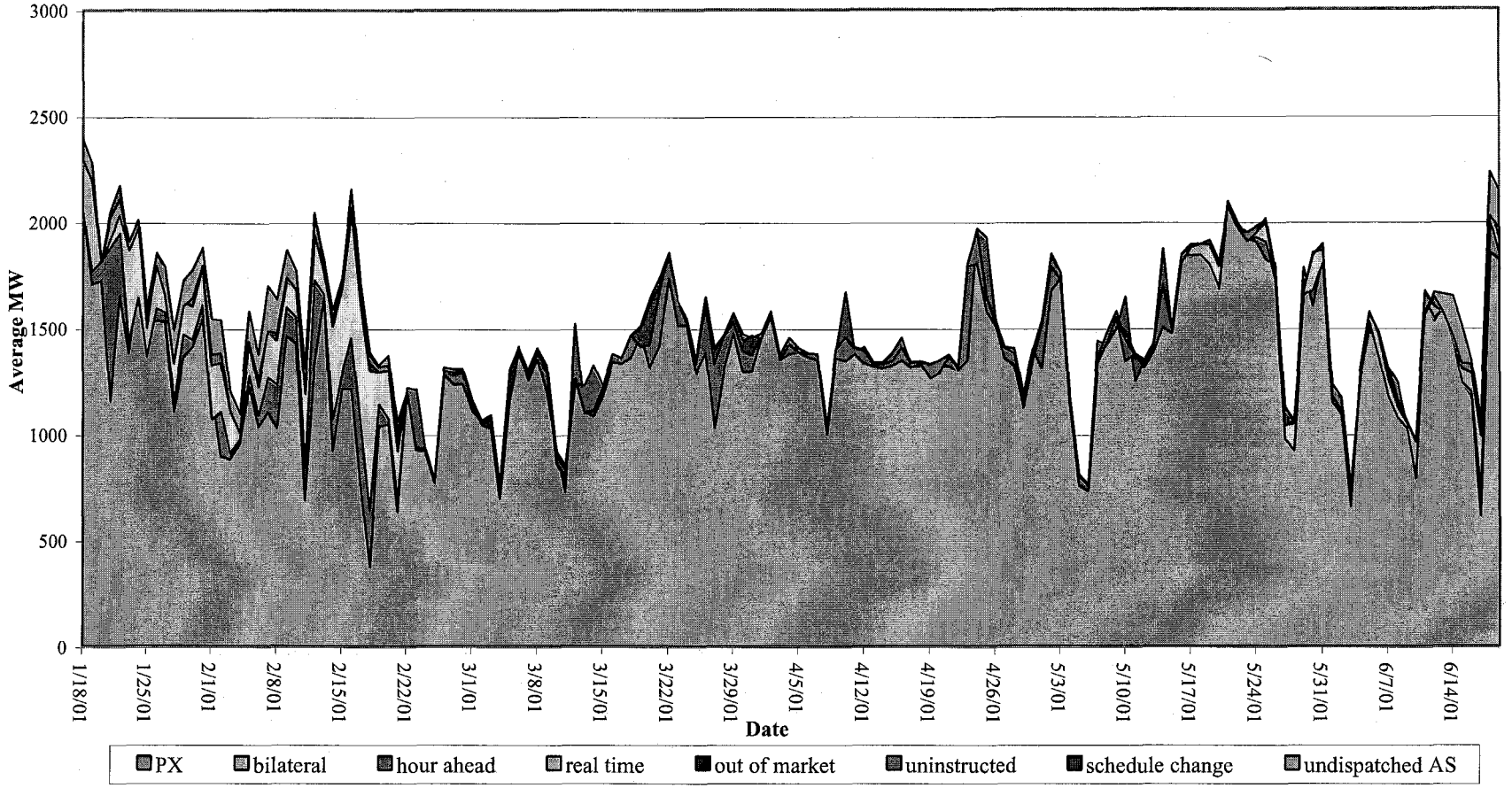
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-4d
Average Megawatts Sold by California Generators (All Hours)
Reliant Energy Services, Inc.
Jan 18, 2001 - Jun 19, 2001



Notes & Sources:

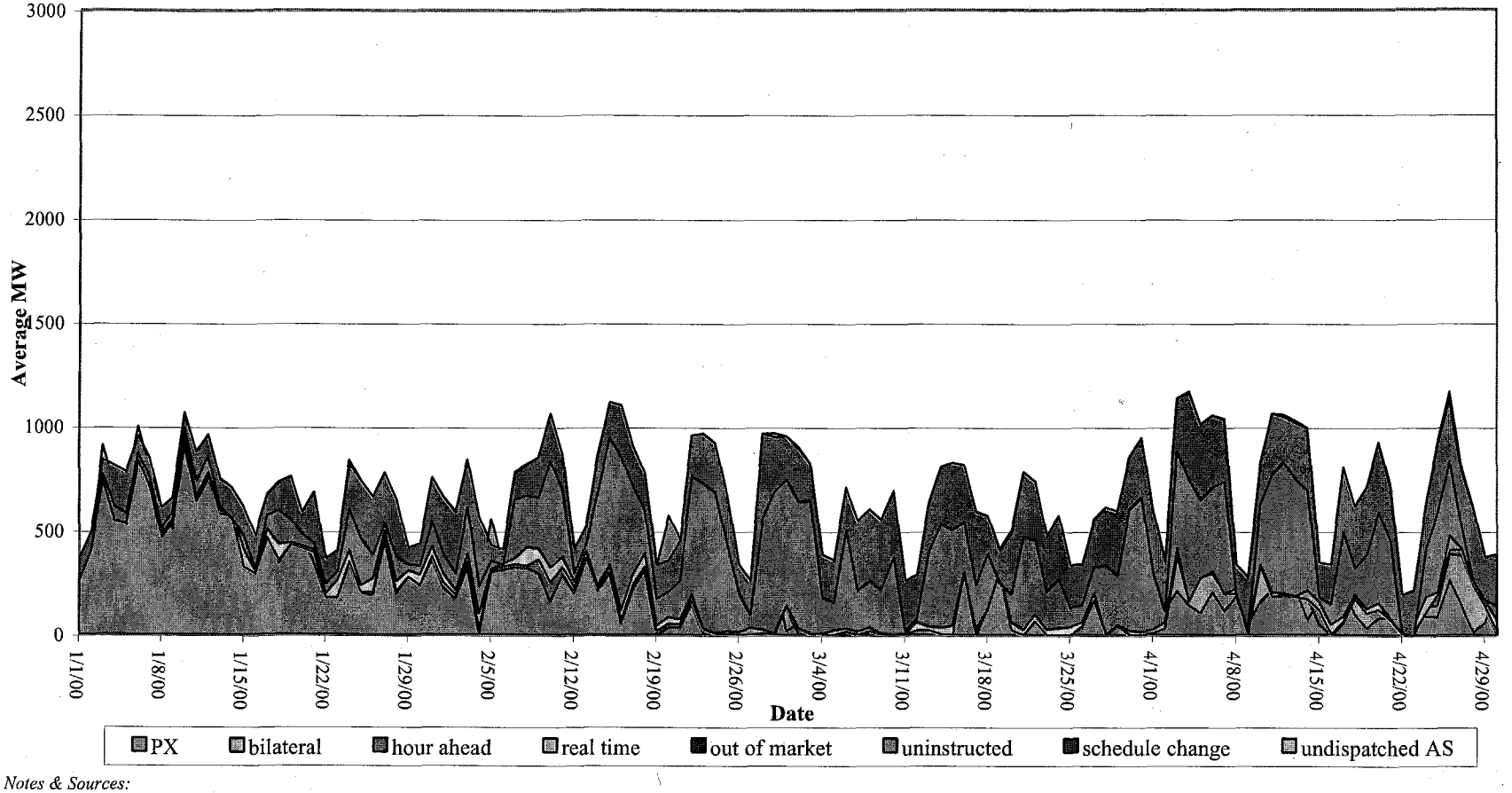
[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure B-5a
Average Megawatts Sold by California Generators (All Hours)
Southern Company Energy Marketing, L.P.
Jan 01, 2000 - Apr 30, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

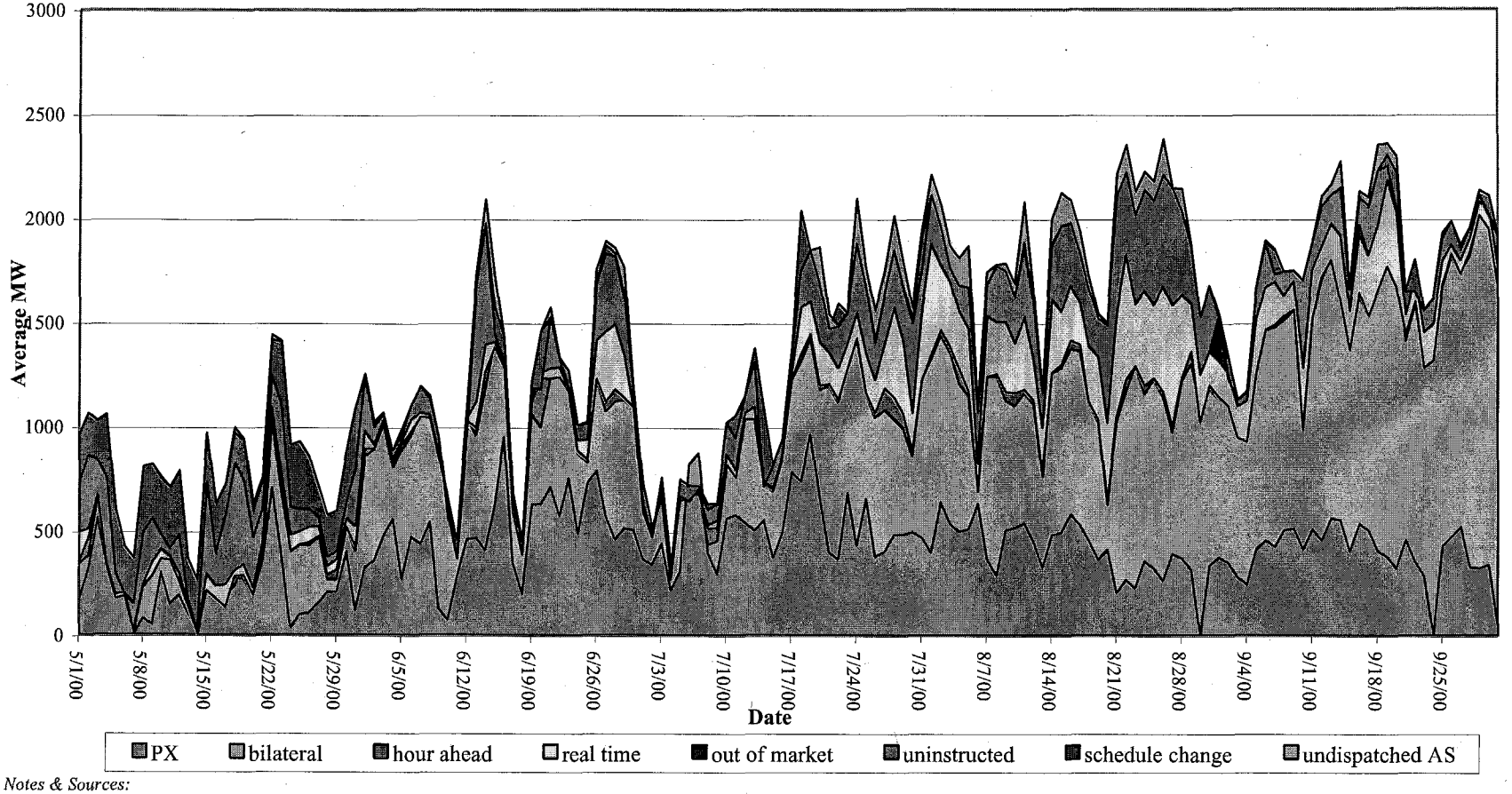
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-5b
Average Megawatts Sold by California Generators (All Hours)
Southern Company Energy Marketing, L.P.
May 01, 2000 - Oct 01, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

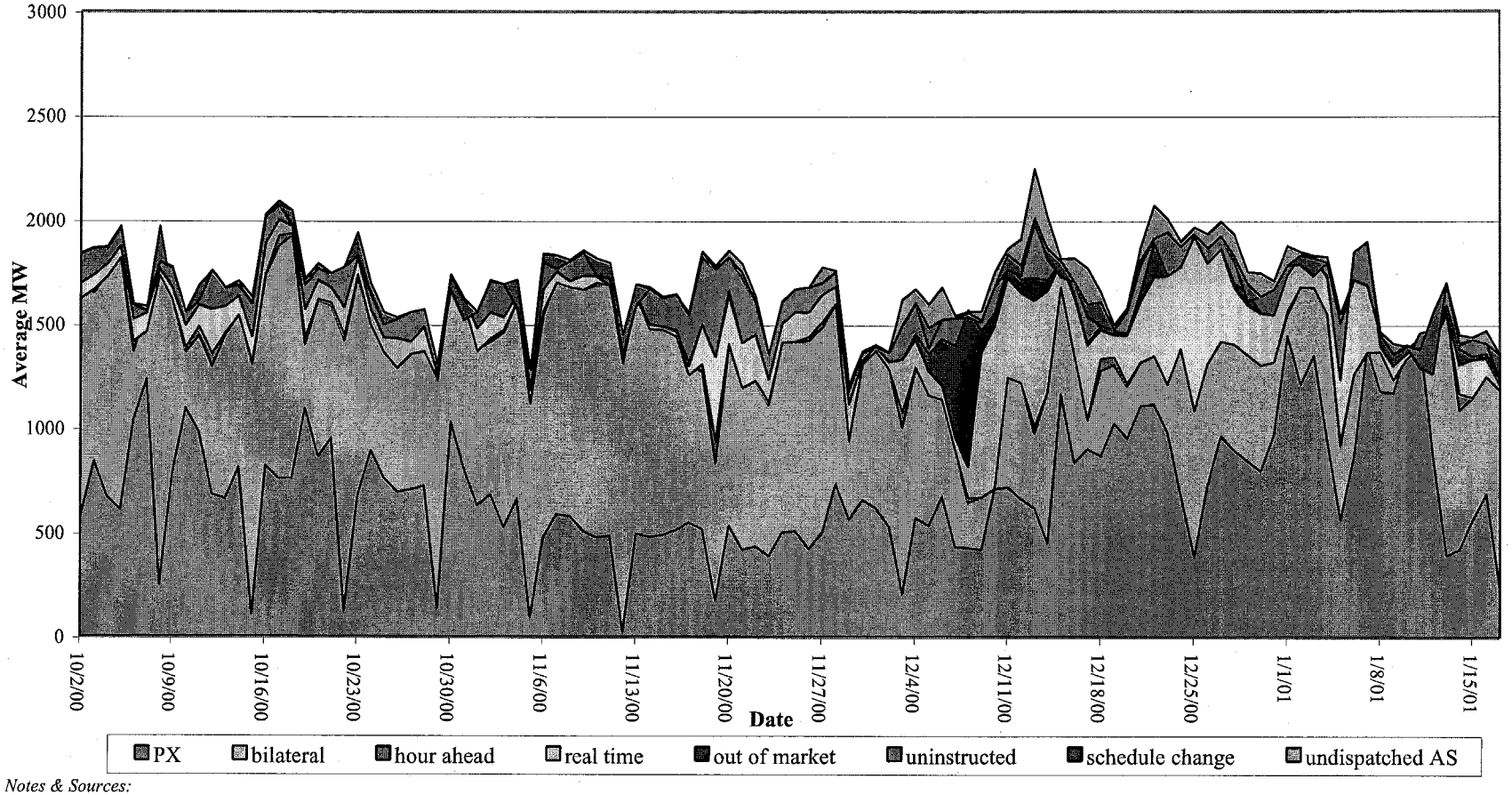
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-5c
Average Megawatts Sold by California Generators (All Hours)
Southern Company Energy Marketing, L.P.
Oct 02, 2000 - Jan 17, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

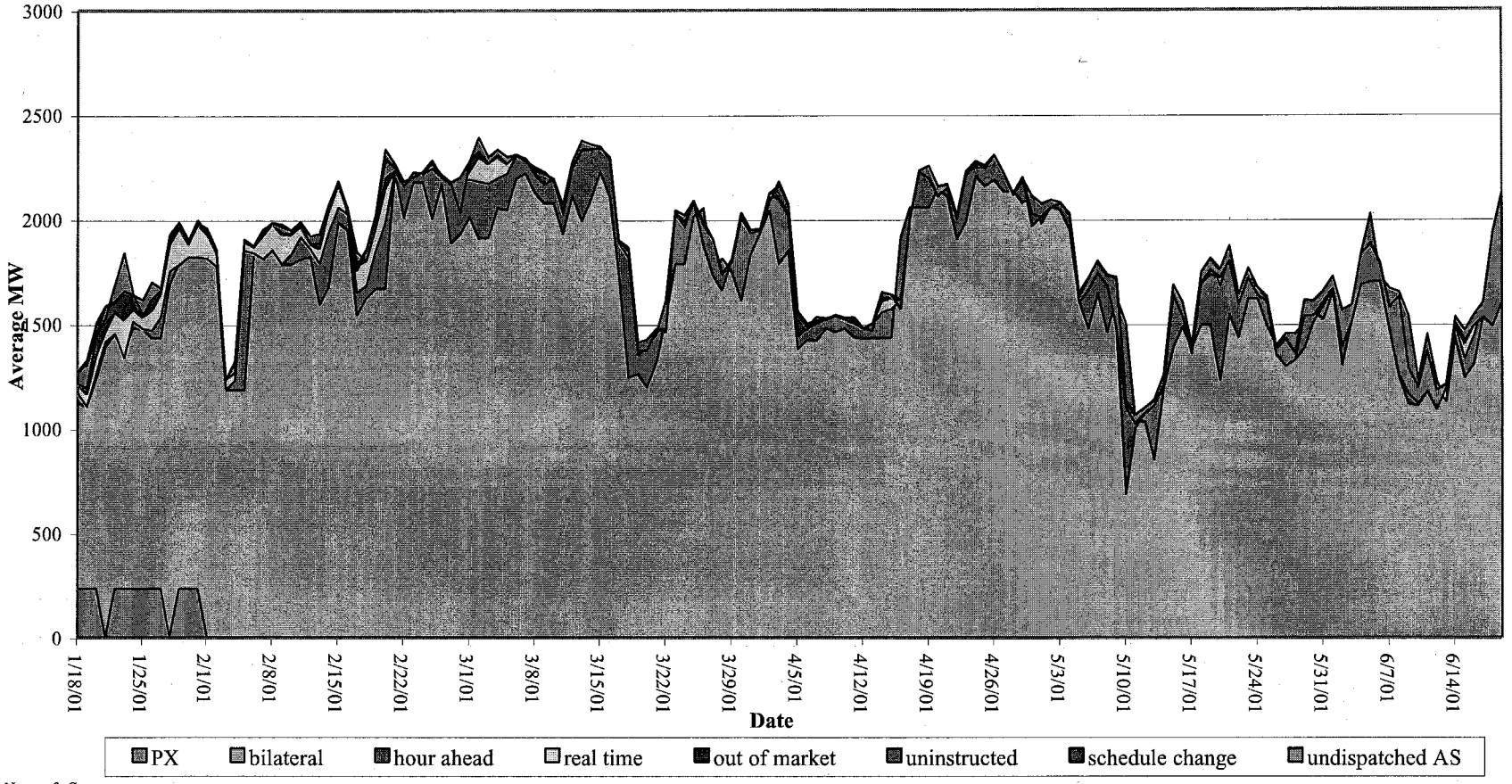
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-5d
Average Megawatts Sold by California Generators (All Hours)
Southern Company Energy Marketing, L.P.
Jan 18, 2001 - Jun 19, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

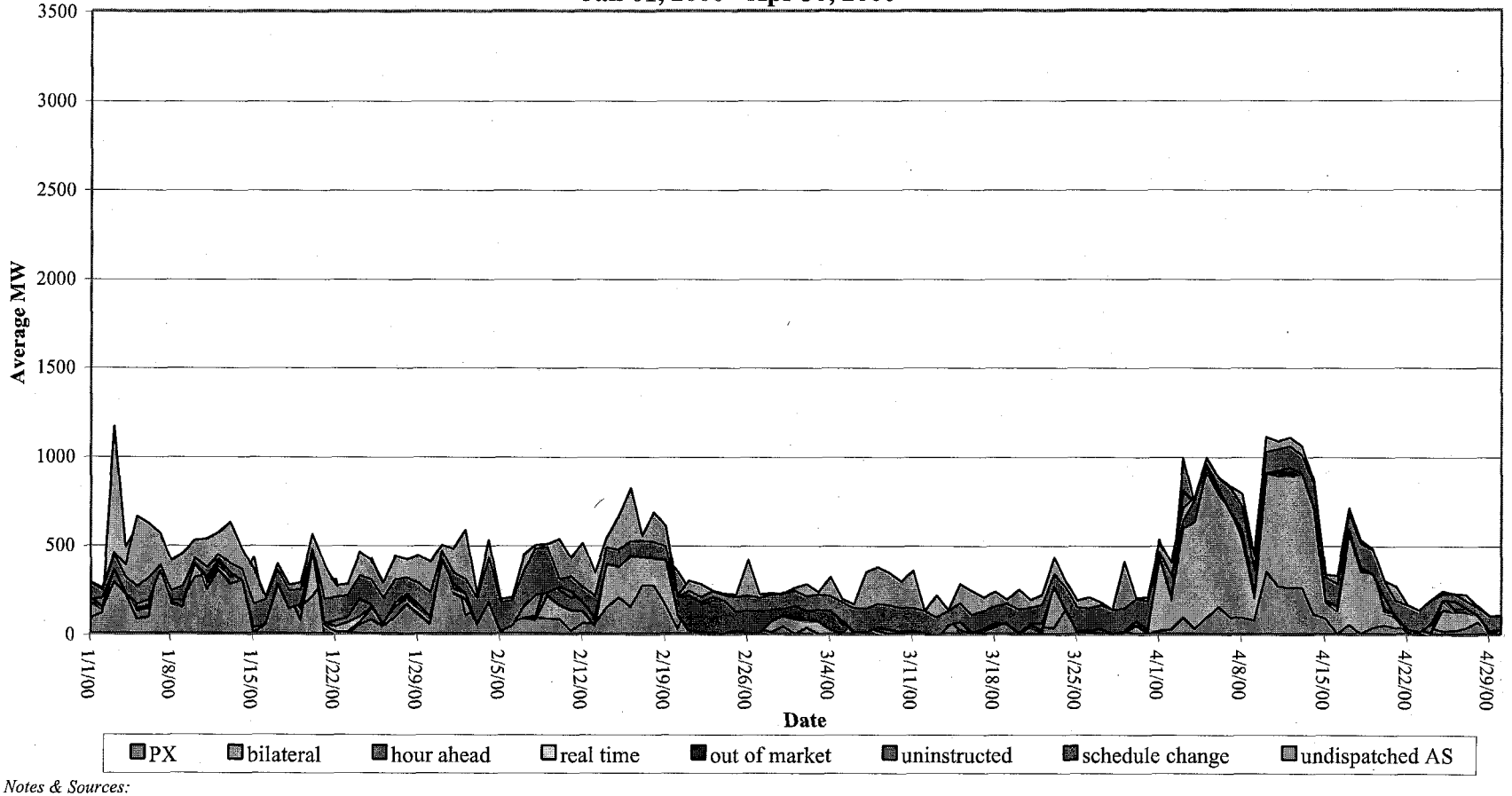
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-6a
Average Megawatts Sold by California Generators (All Hours)
Williams Energy Services Corporation
Jan 01, 2000 - Apr 30, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

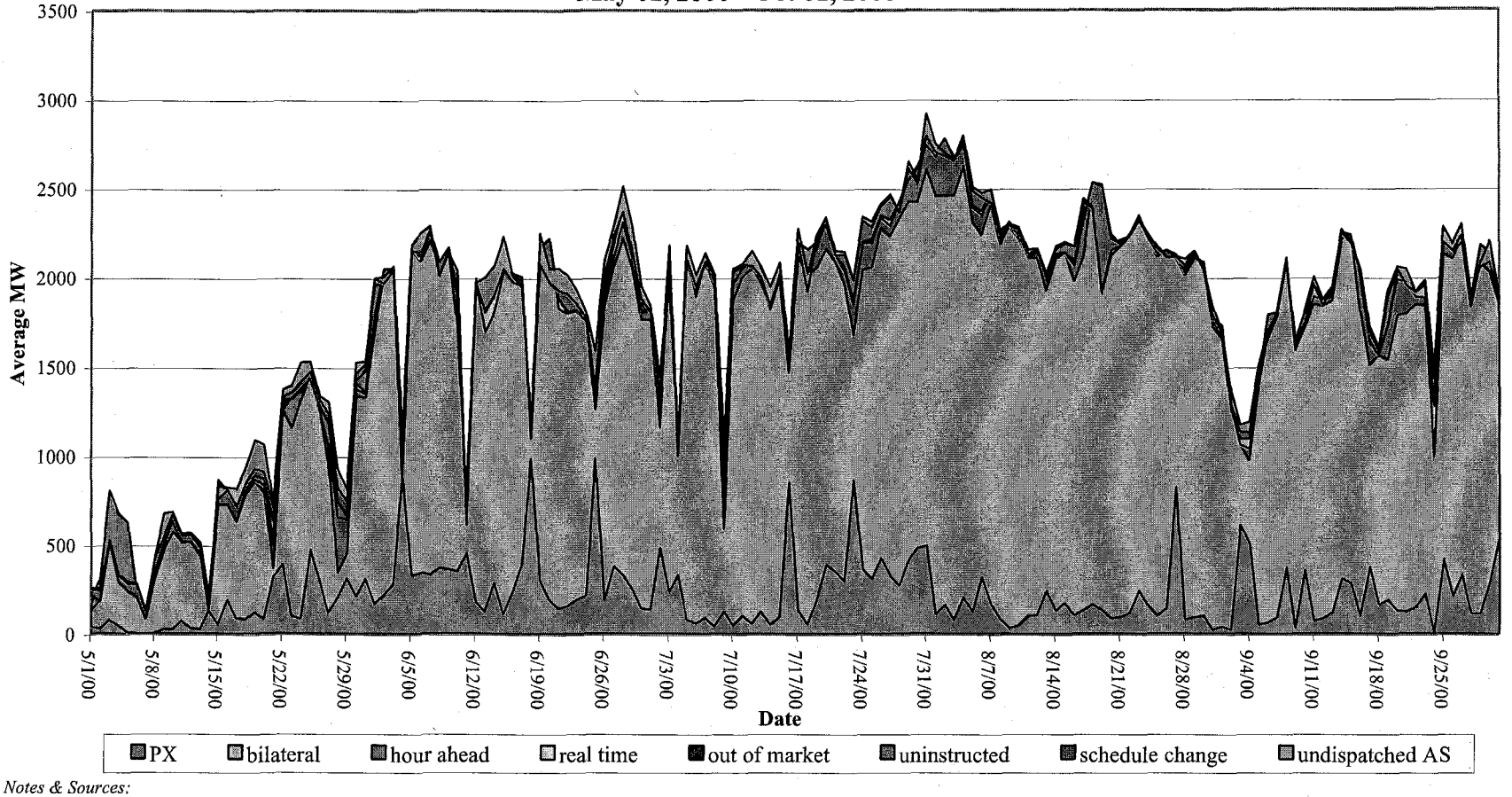
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-6b
Average Megawatts Sold by California Generators (All Hours)
Williams Energy Services Corporation
May 01, 2000 - Oct 01, 2000



Notes & Sources:

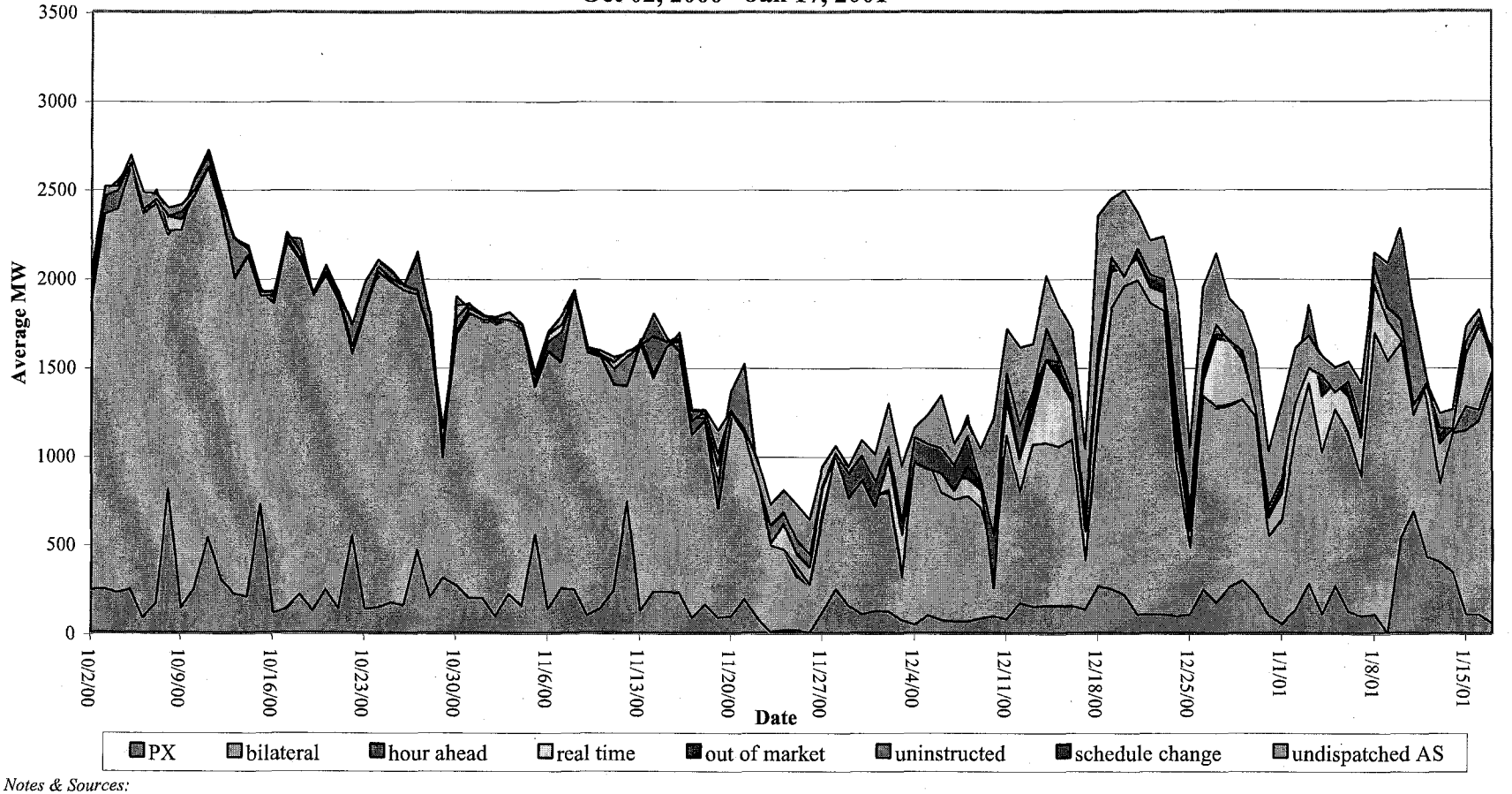
[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure B-6c
Average Megawatts Sold by California Generators (All Hours)
Williams Energy Services Corporation
Oct 02, 2000 - Jan 17, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

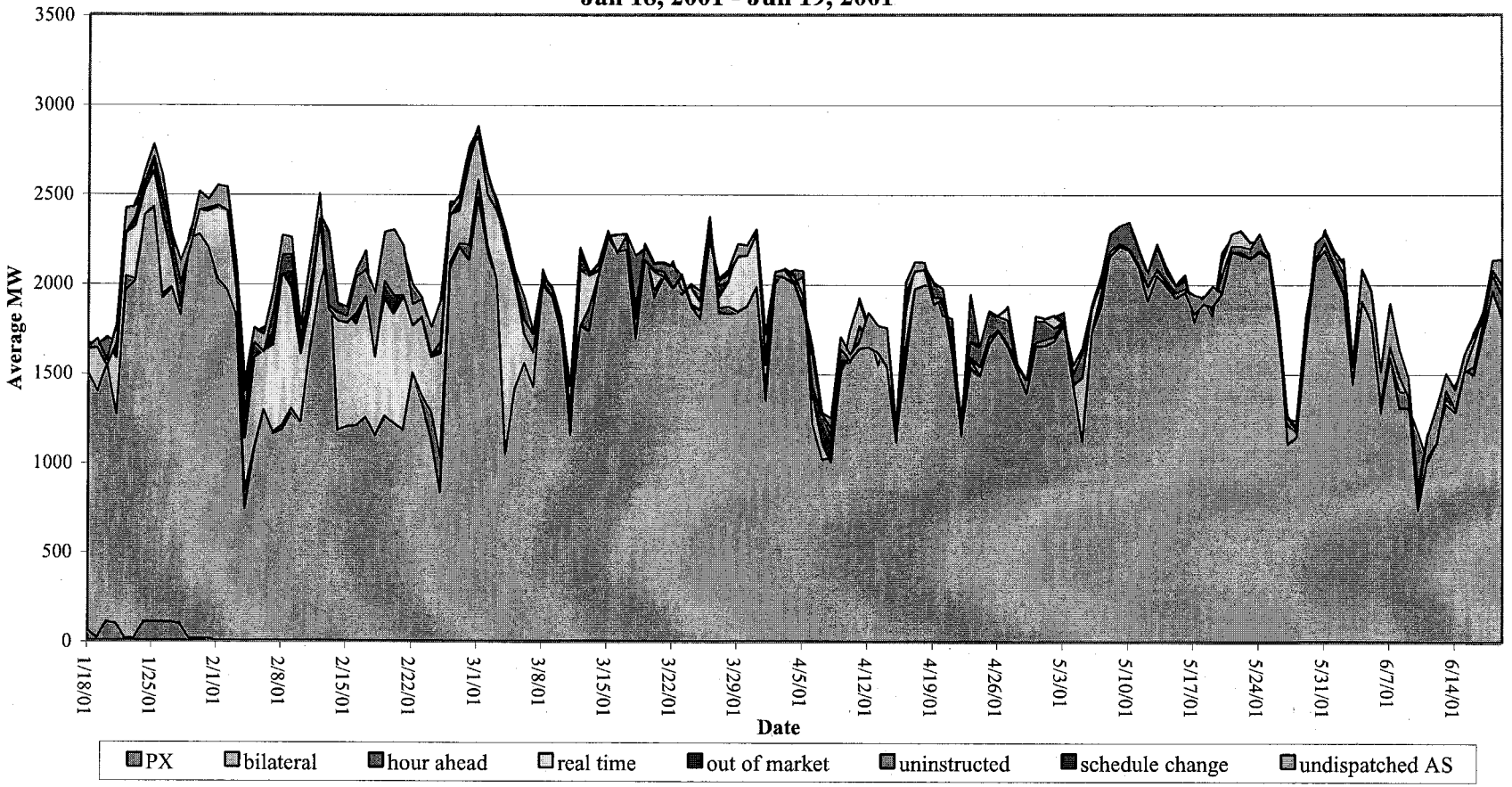
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-6d
Average Megawatts Sold by California Generators (All Hours)
Williams Energy Services Corporation
Jan 18, 2001 - Jun 19, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

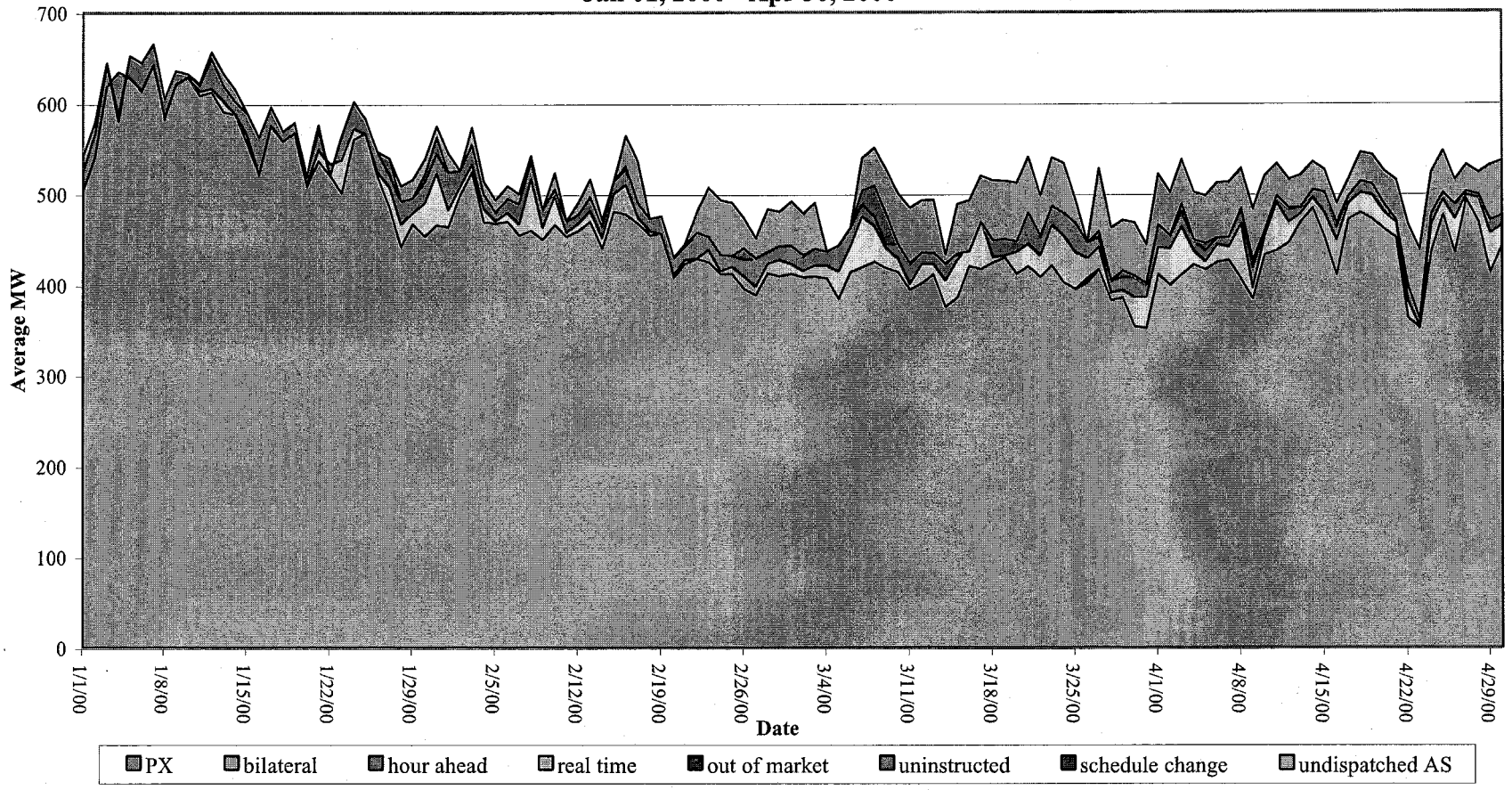
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-7a
Average Megawatts Sold by California Generators (All Hours)
Calpine Corporation
Jan 01, 2000 - Apr 30, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

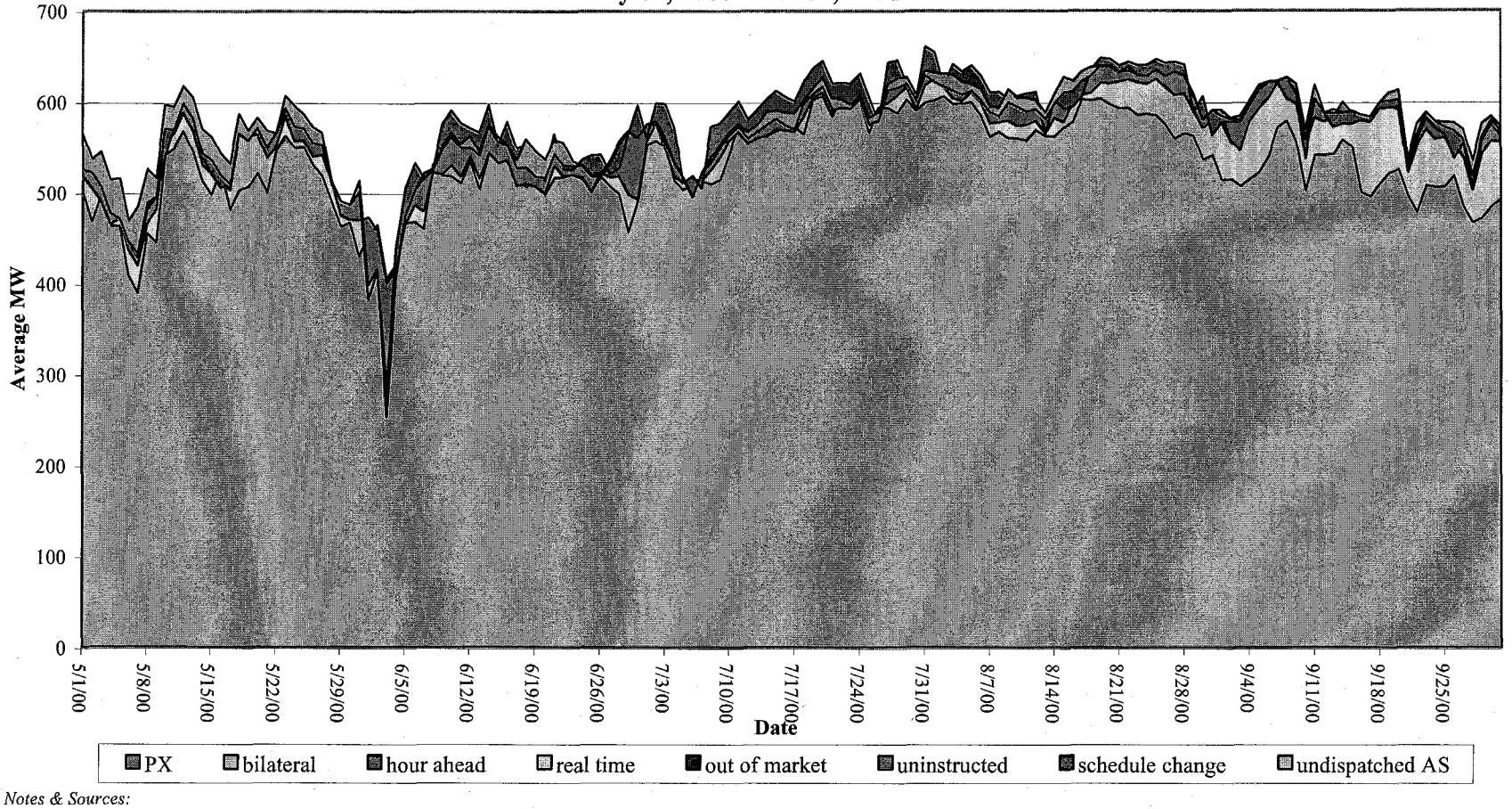
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-7b
Average Megawatts Sold by California Generators (All Hours)
Calpine Corporation
May 01, 2000 - Oct 01, 2000



Notes & Sources:

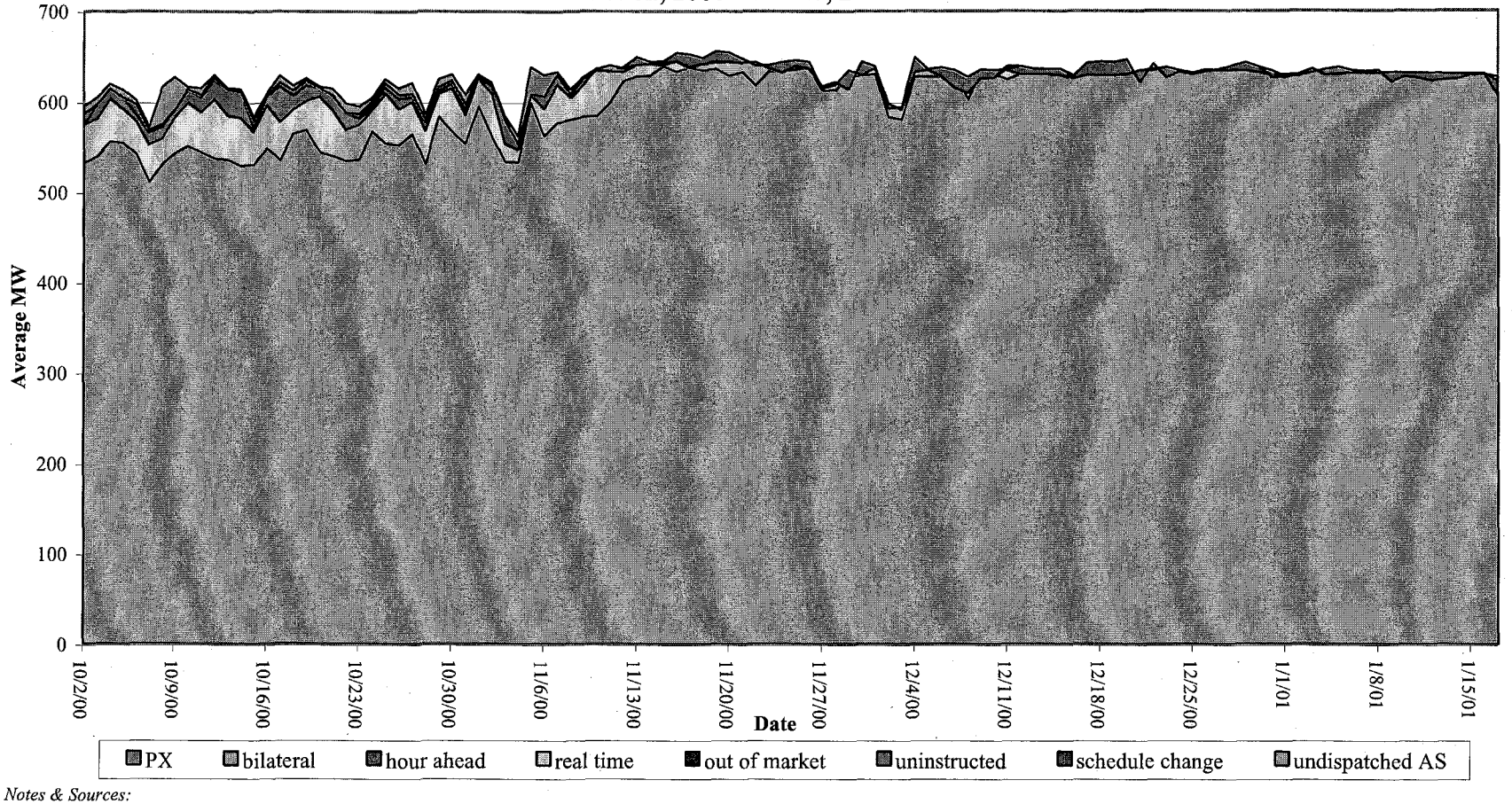
[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure B-7c
Average Megawatts Sold by California Generators (All Hours)
Calpine Corporation
Oct 02, 2000 - Jan 17, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

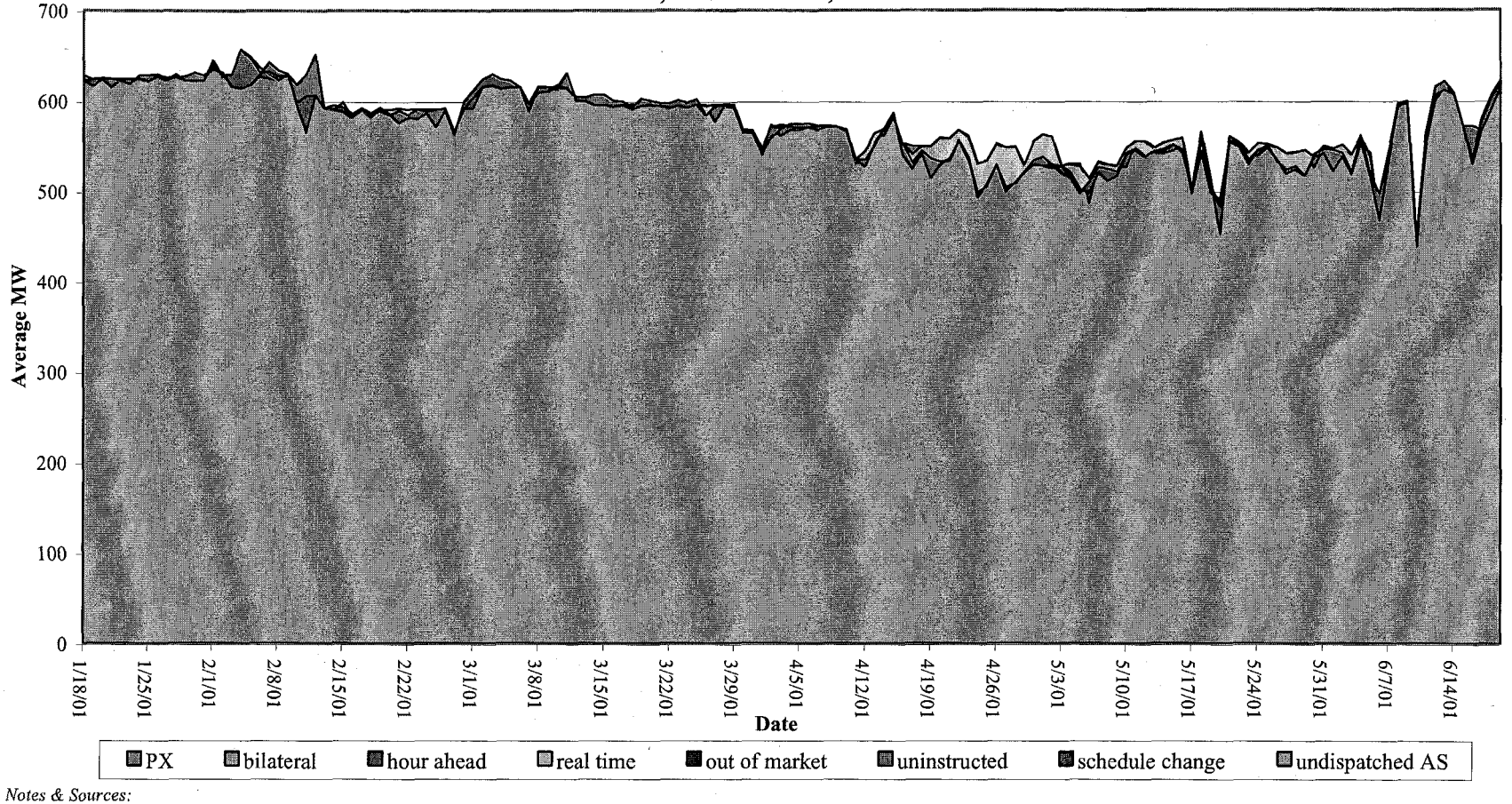
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-7d
Average Megawatts Sold by California Generators (All Hours)
Calpine Corporation
Jan 18, 2001 - Jun 19, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

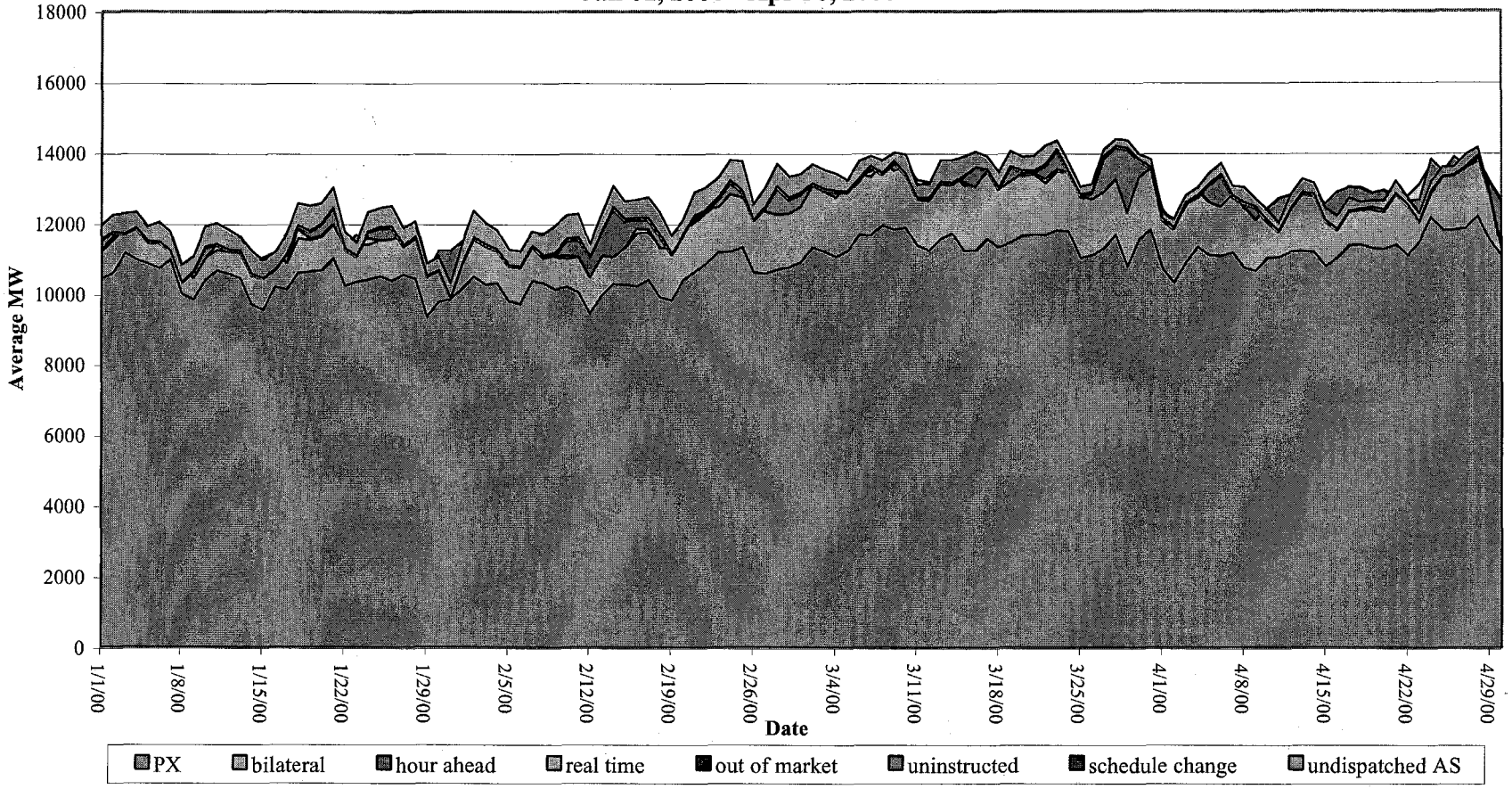
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

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Figure B-8a
Average Megawatts Sold by California Generators (All Hours)
California IOUs
Jan 01, 2000 - Apr 30, 2000



Notes & Sources:

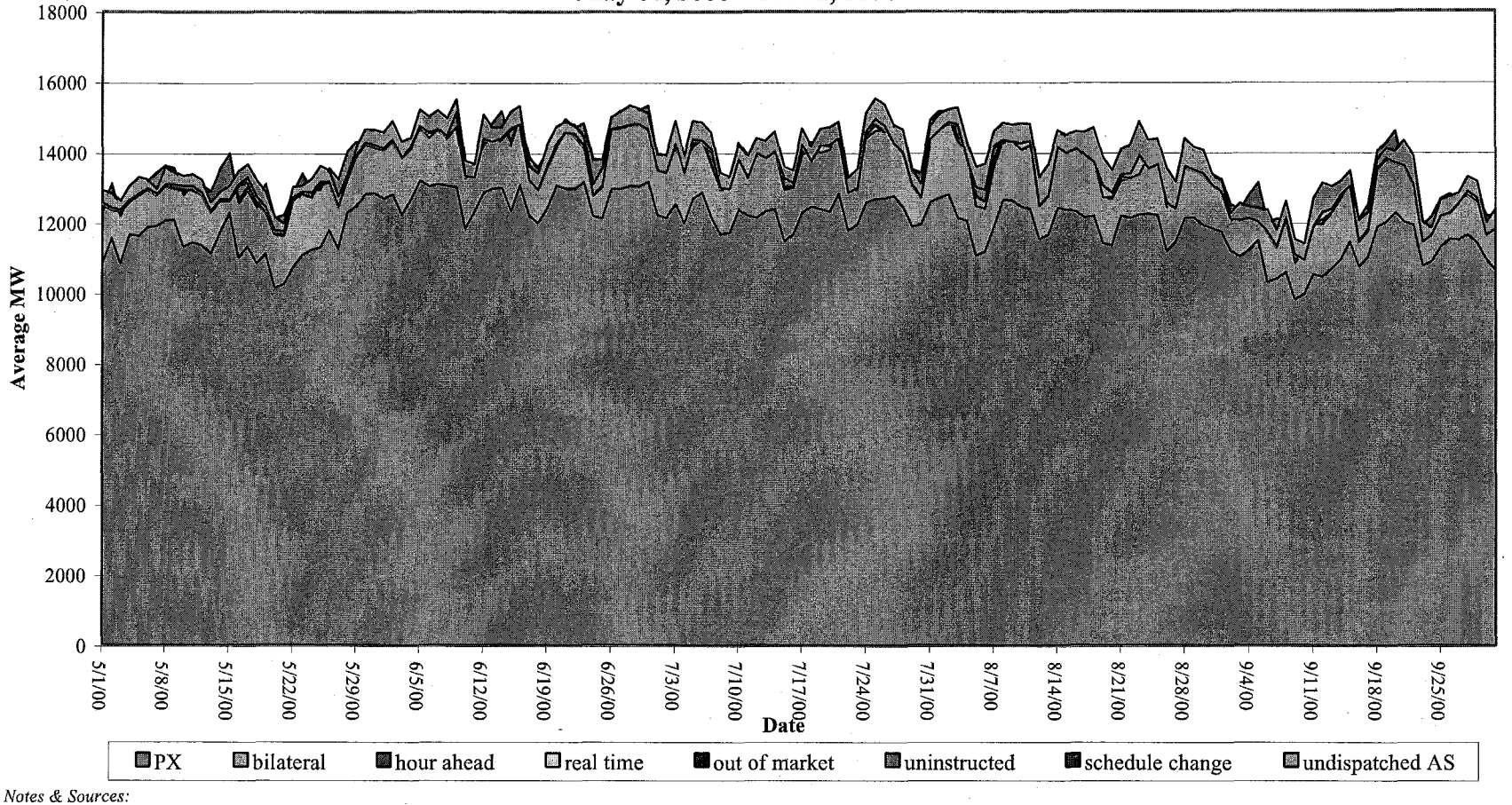
[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure B-8b
Average Megawatts Sold by California Generators (All Hours)
California IOUs
May 01, 2000 - Oct 01, 2000



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

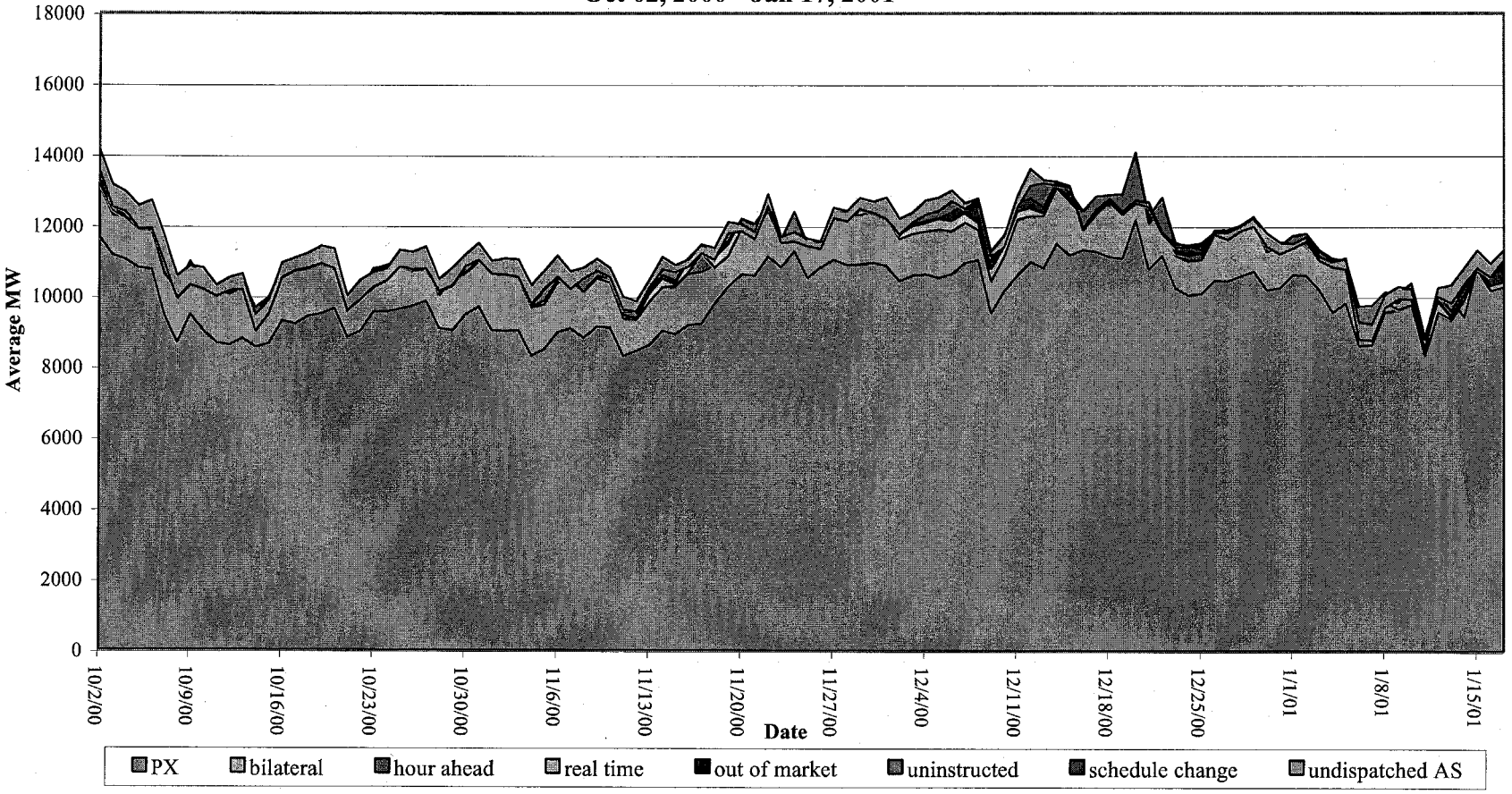
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

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Figure B-8c
Average Megawatts Sold by California Generators (All Hours)
California IOUs
Oct 02, 2000 - Jan 17, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

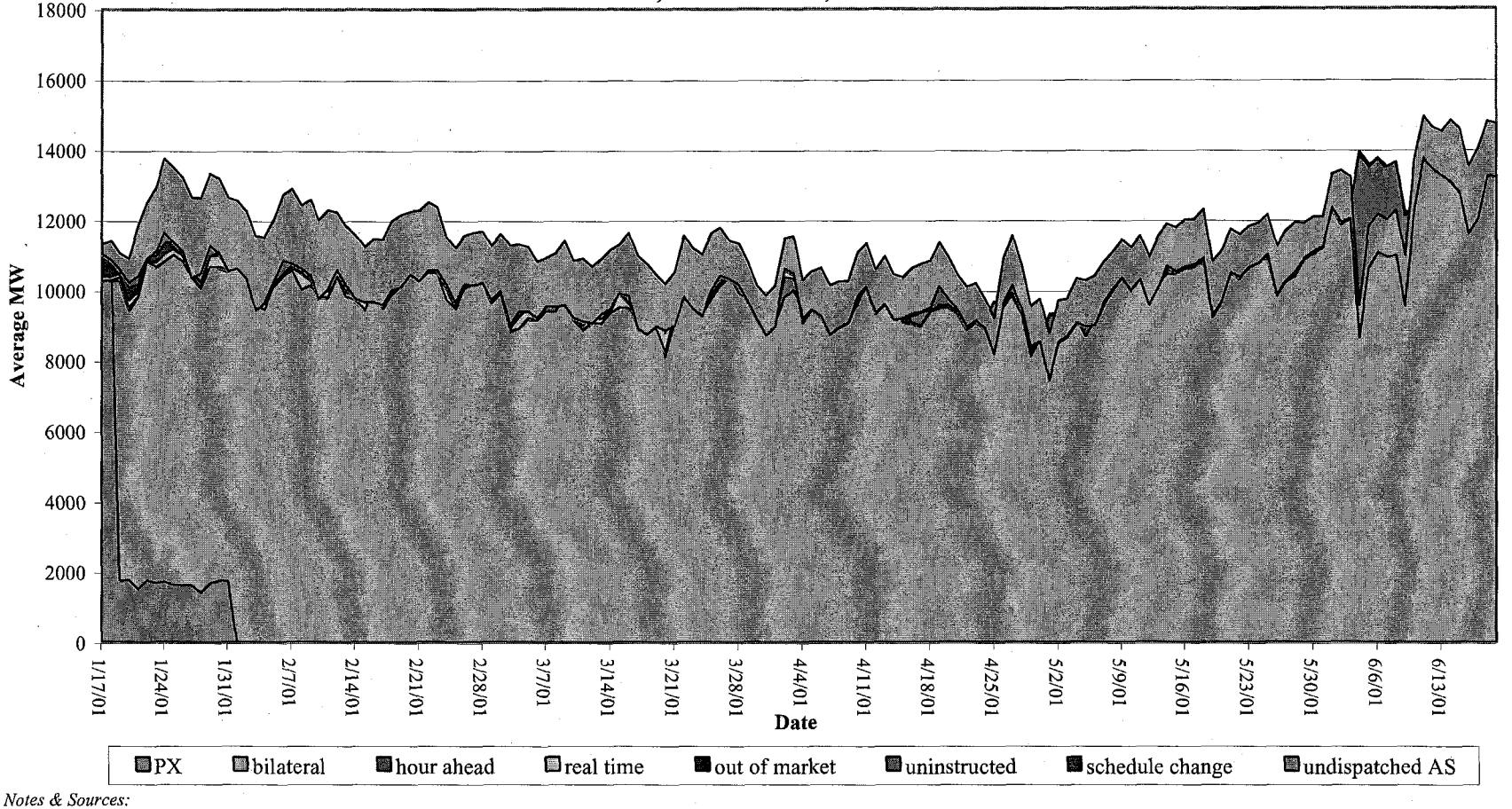
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure B-8d
Average Megawatts Sold by California Generators (All Hours)
California IOUs
Jan 17, 2001 - Jun 19, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change are output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

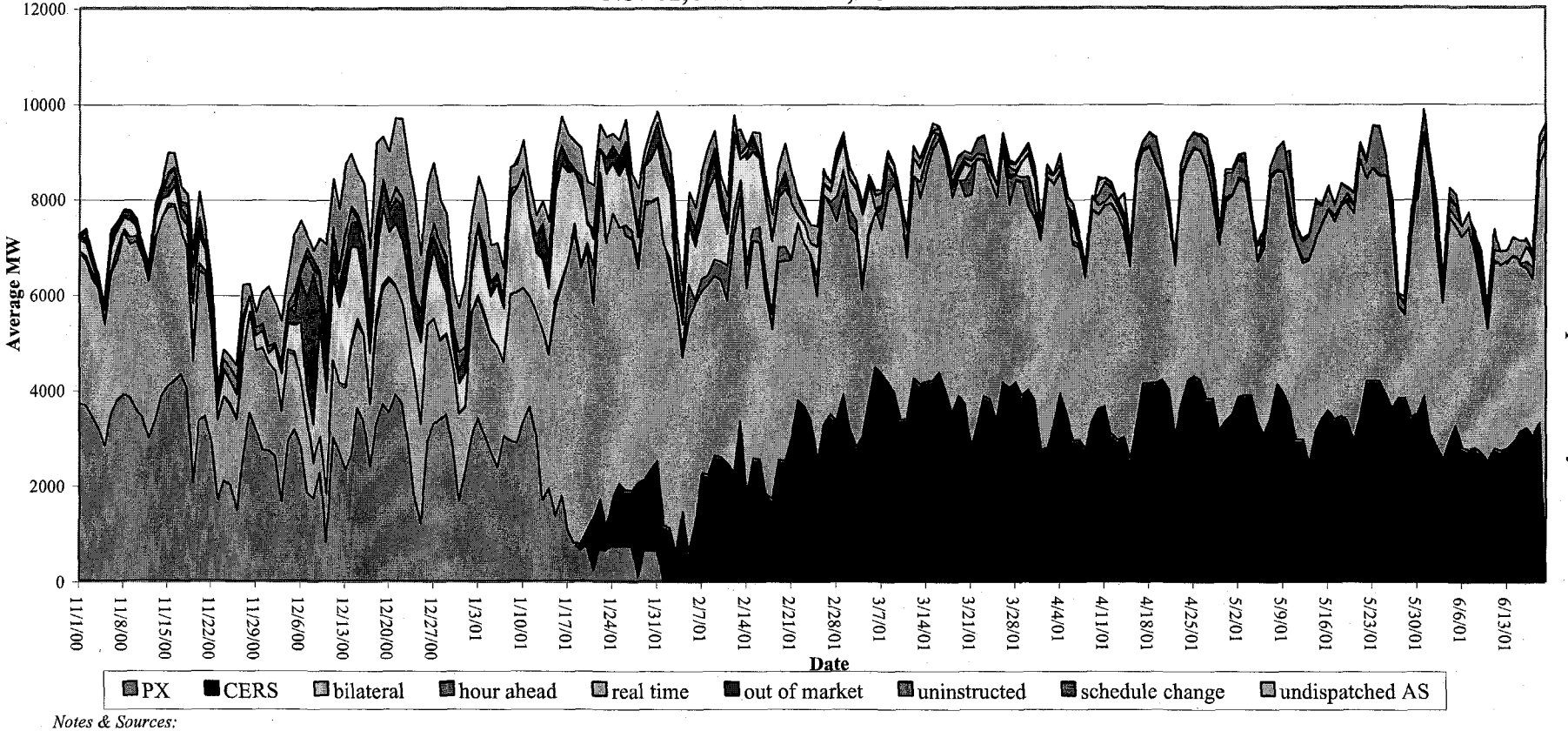
[3]: Sales into Cal PX reflect total supplier (not unit-specific) PX Supply data. Bilaterals are Day-Ahead final schedule less PX supply; from Response to Data Request CAL-PX-1 and CAL-PX-2.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

[5]: Negative uninstructed in June 2001 is driven by QF's who are scheduled by SCE but did not operate (likely to protest the fact that they had not been paid due to SCE's financial distress).

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Figure B-9
Average Megawatts Sold by California Generators (All Hours)
Big Five
Nov 01, 2000 - Jun 19, 2001



Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time, Undispatched AS & Schedule Change is output from generating units within California only; from Response to Data Request CAL-ISO-4 and data provided by AG.

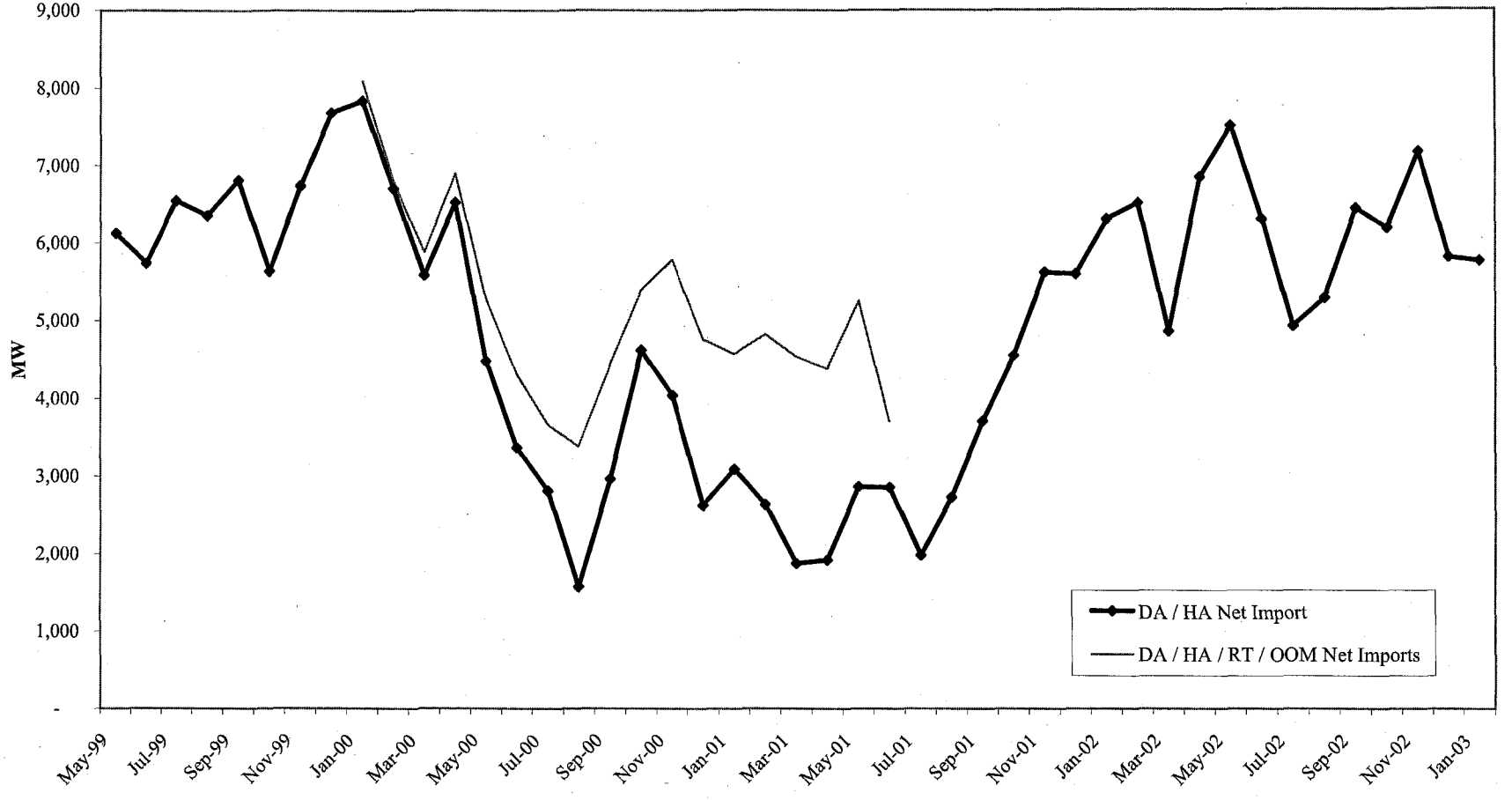
[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Sales into Cal PX reflect day-ahead total supplier (not unit-specific) PX Supply data; from Response to Data Request CAL-PX-1 and CAL-PX-2. CERS Bilaterals are CERS day-ahead purchases from within California only; from CERS transaction data. Bilaterals are Day-Ahead final schedule less PX supply and CERS bilaterals.

[4]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

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Not Available to Competitive Duty Personnel

Figure C-1
Hourly Average California ISO DA/HA Net Imports by Month
Total California ISO Imports and Exports
May 1999 to January 2003

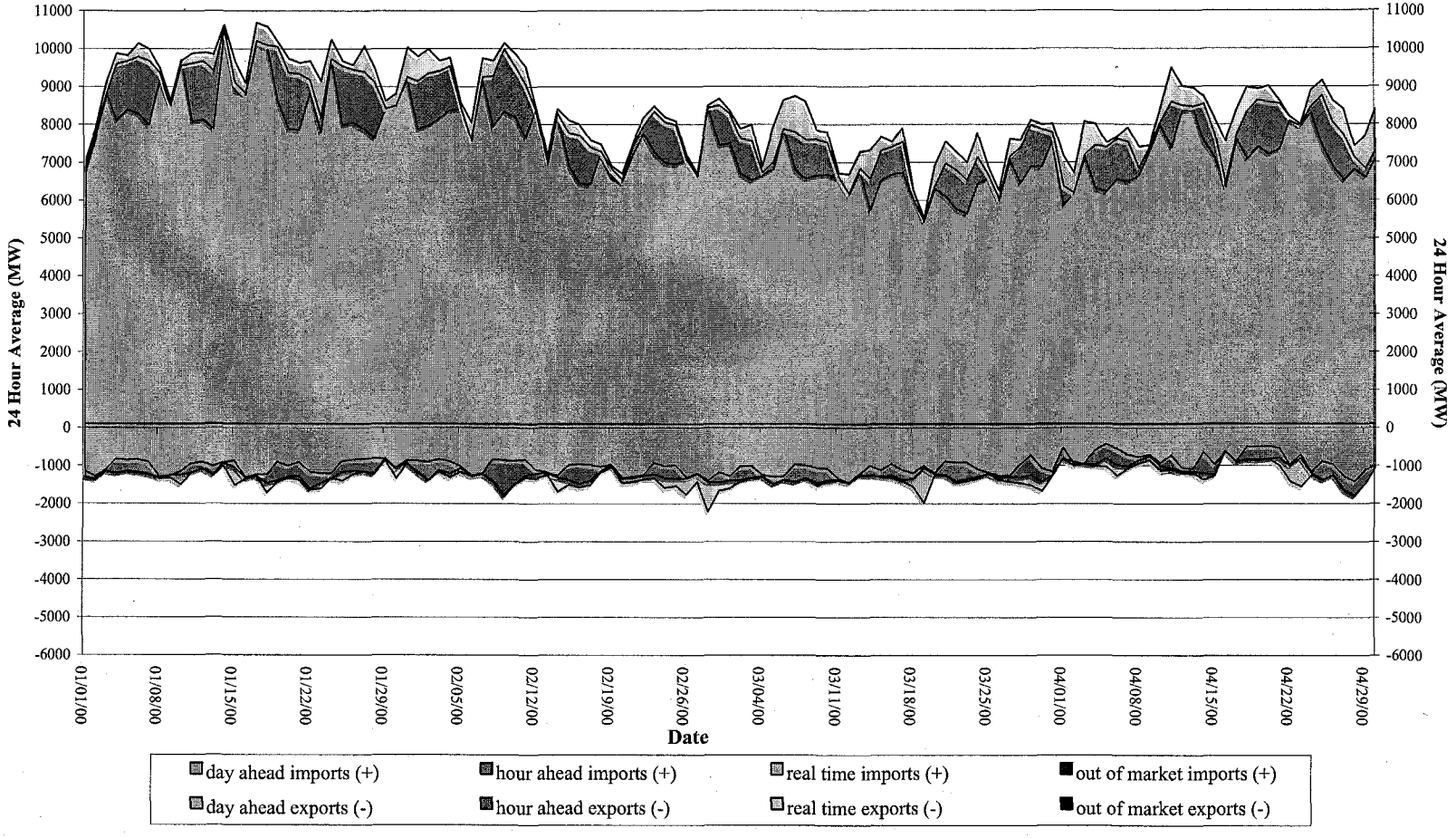


Source: University of California Energy Institute (http://www.ucei.berkeley.edu/ucei/datamine/iso_eng_system.htm),
CAISO OASIS Load and Resource Schedules Reports (http://oasis.caiso.com), California ISO Response to Data Requests CAL-ISO-4 and CAL-ISO-7.

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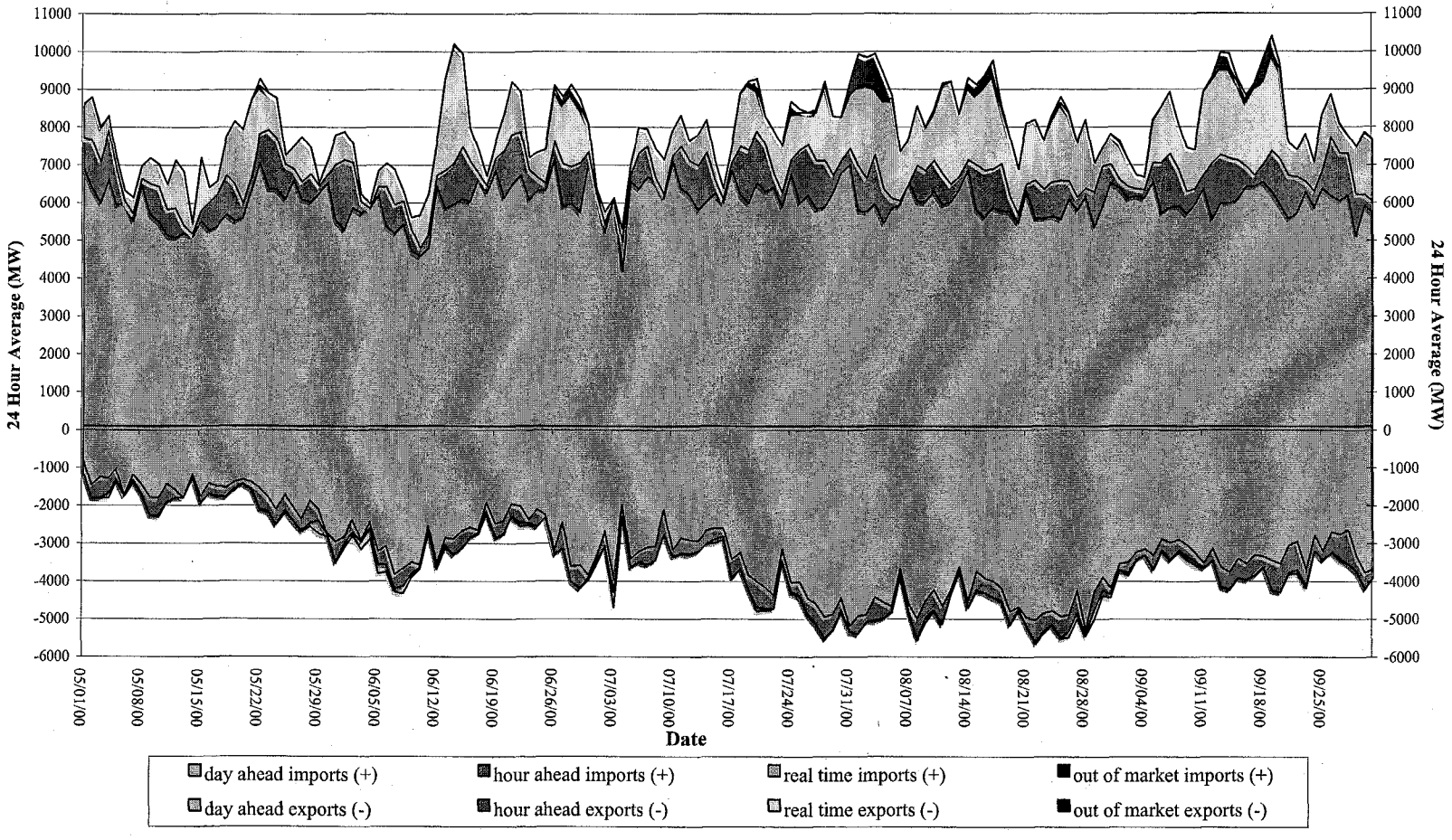
Figure C-2a
Hourly Average California ISO Imports and Exports
Total California ISO Imports and Exports
Jan 01, 2000 - Apr 30, 2000



Sources and Notes:
[1]: Sources are California ISO Responses to Data Requests CAL-ISO-4 and CAL-ISO-7.
[2]: Positive values represent imports into the California ISO, and negative values represent exports out of the California ISO.

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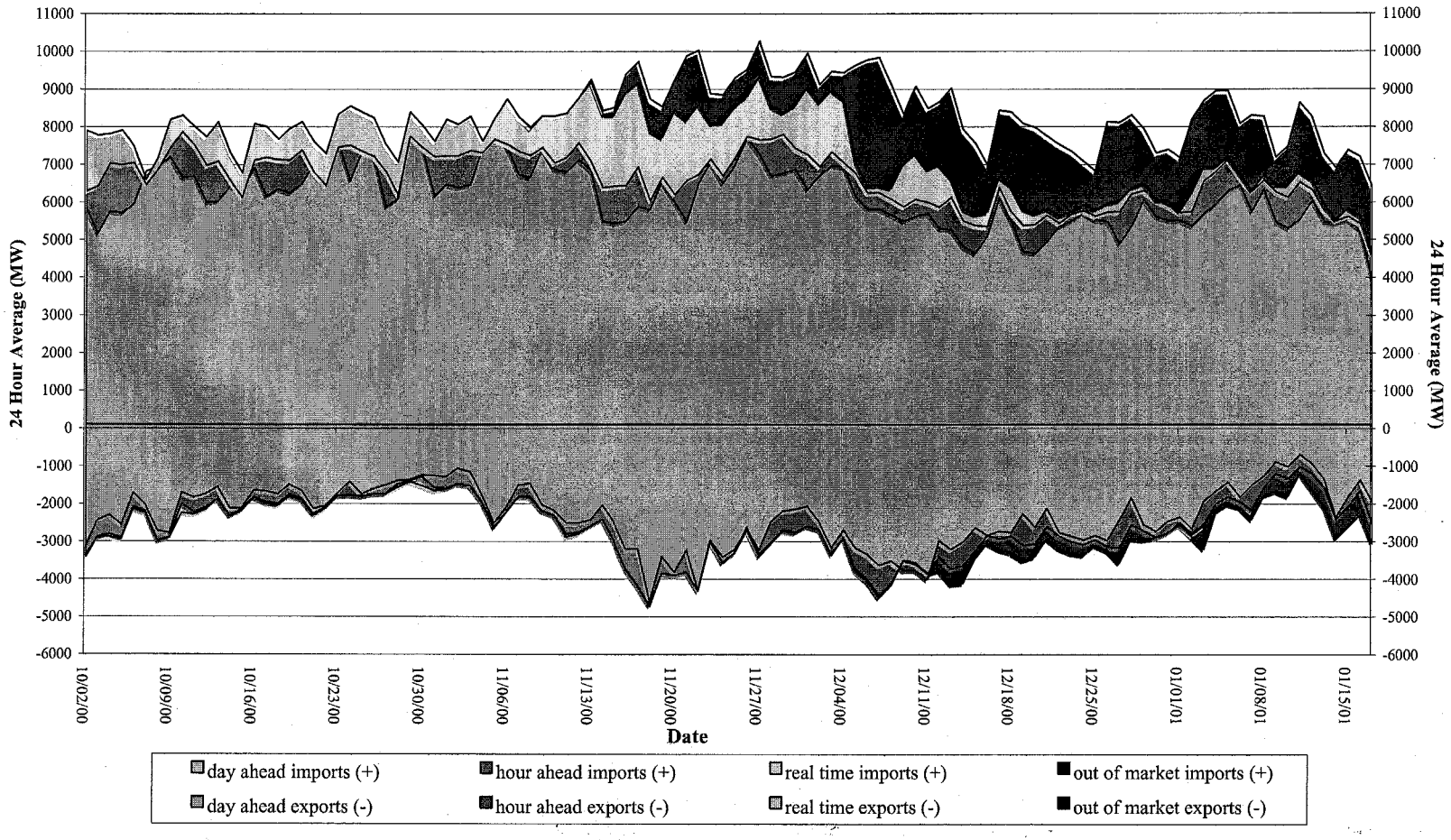
Figure C-2b
Hourly Average California ISO Imports and Exports
Total California ISO Imports and Exports
May 01, 2000 - Oct 01, 2000



Sources and Notes:
[1]: Sources are California ISO Responses to Data Requests CAL-ISO-4 and CAL-ISO-7.
[2]: Positive values represent imports into the California ISO, and negative values represent exports out of the California ISO.

Contains Protected Material
Not Available to Competitive Duty Personnel

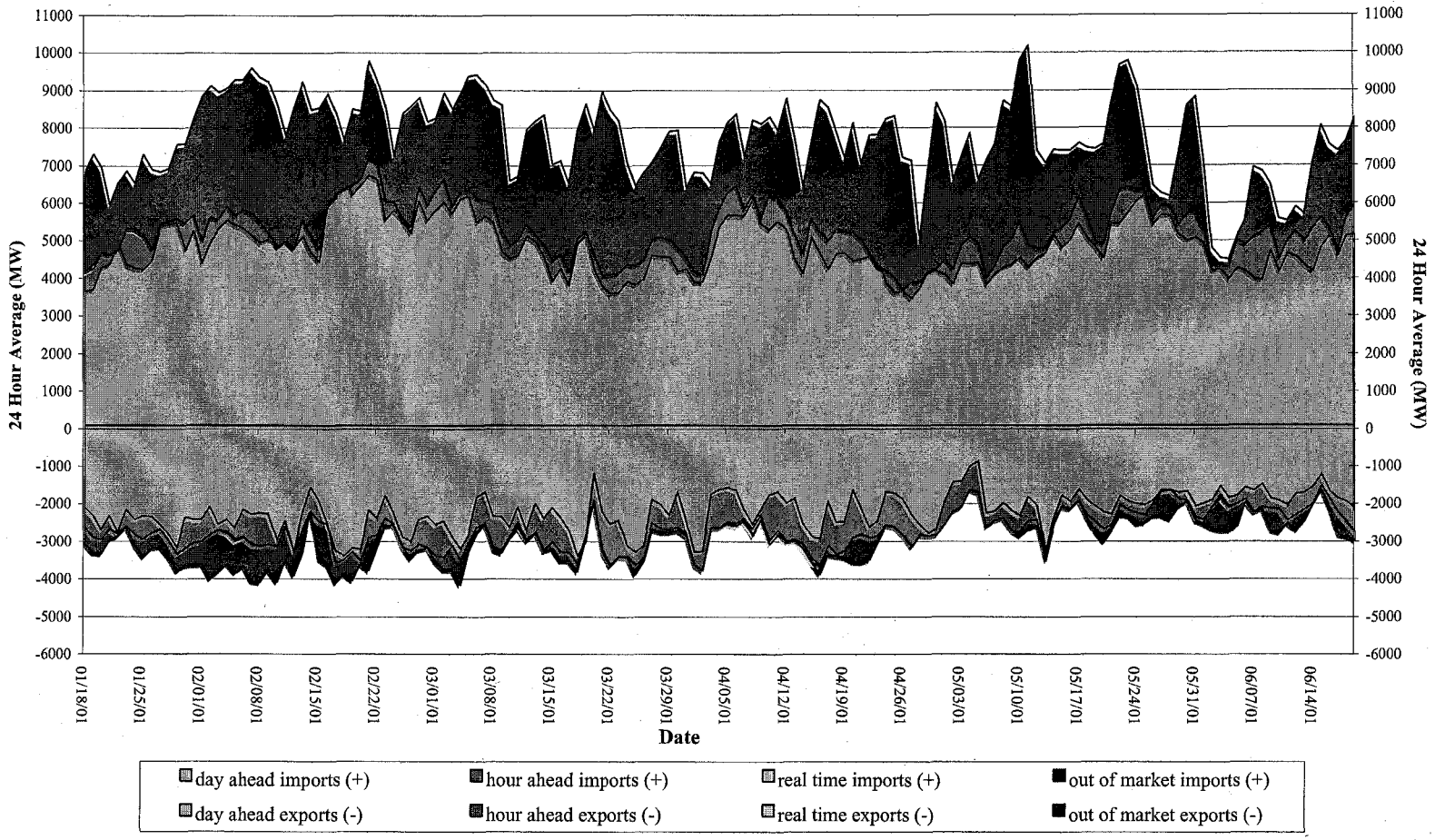
Figure C-2c
Hourly Average California ISO Imports and Exports
Total California ISO Imports and Exports
Oct 02, 2000 - Jan 17, 2001



Sources and Notes:
[1]: Sources are California ISO Responses to Data Requests CAL-ISO-4 and CAL-ISO-7.
[2]: Positive values represent imports into the California ISO, and negative values represent exports out of the California ISO.

Contains Protected Material
Not Available to Competitive Duty Personnel

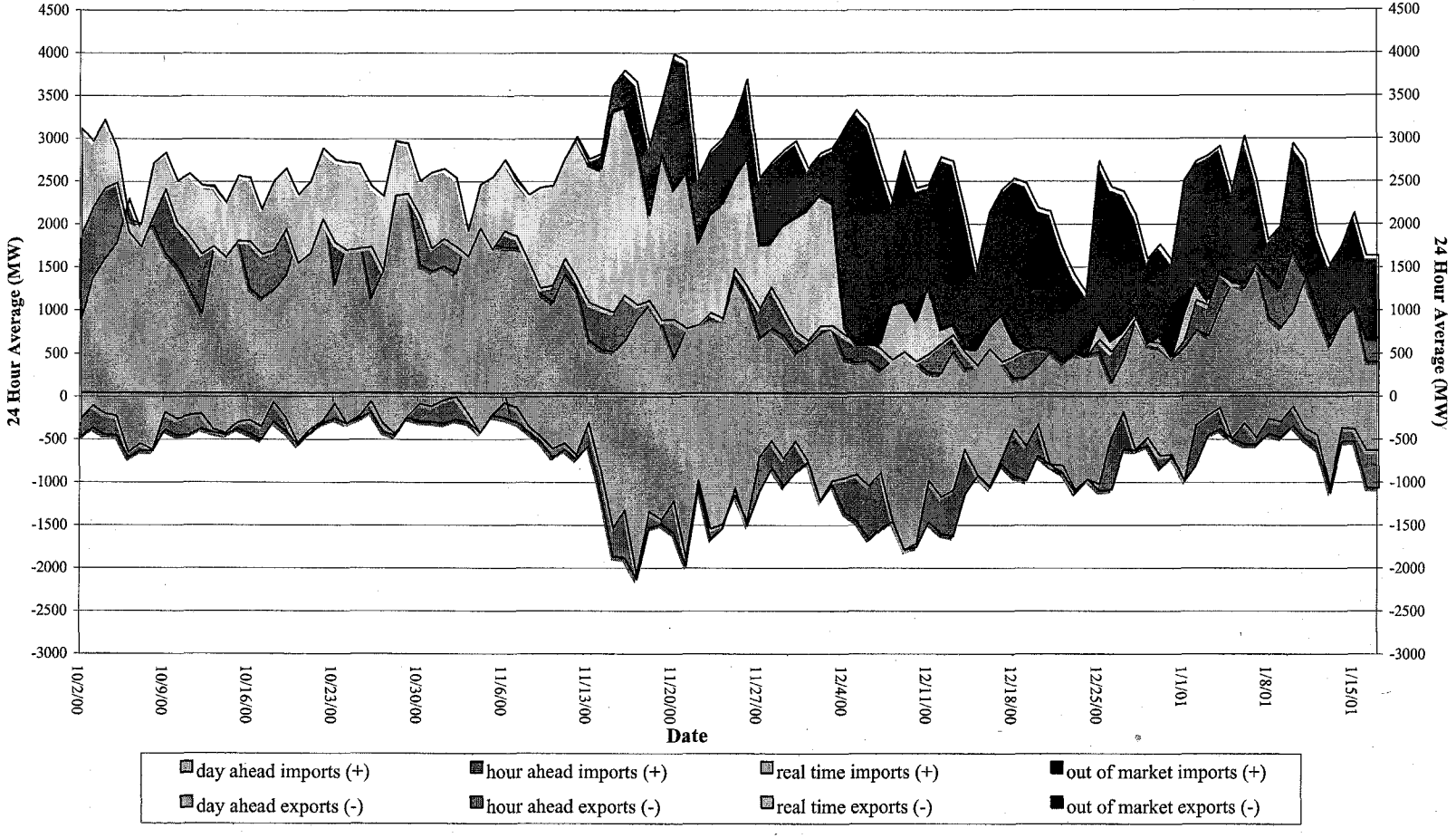
Figure C-2d
Hourly Average California ISO Imports and Exports
Total California ISO Imports and Exports
Jan 18, 2001 - Jun 19, 2001



Sources and Notes:
[1]: Sources are California ISO Responses to Data Requests CAL-ISO-4 and CAL-ISO-7.
[2]: Positive values represent imports into the California ISO, and negative values represent exports out of the California ISO.

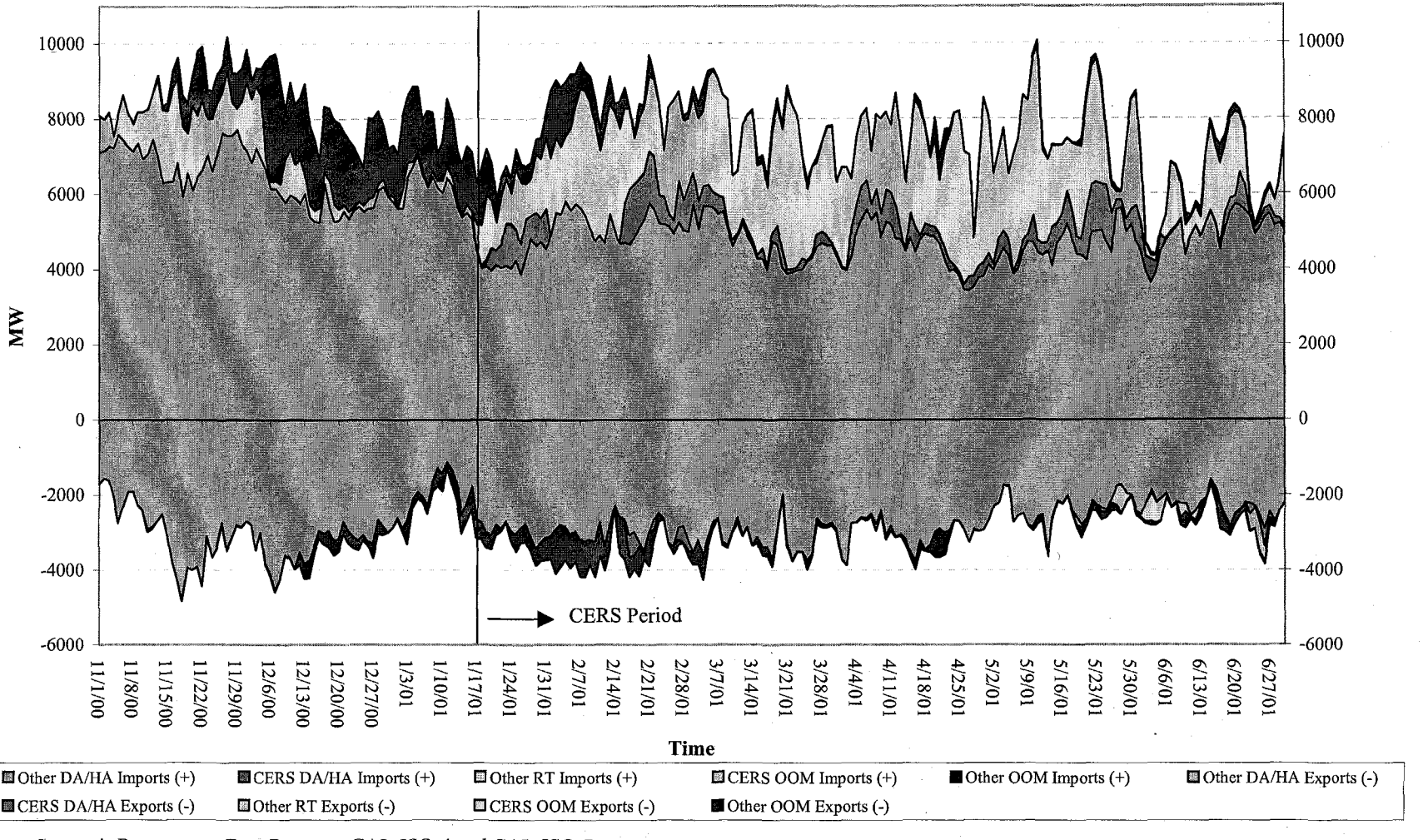
Contains Protected Material
Not Available to Competitive Duty Personnel

Figure C-3
Hourly Average California ISO Imports and Exports
California ISO Imports and Exports between NP15 and the Northwest
Oct 02, 2000 - Jan 17, 2001



Sources and Notes:
[1]: Sources are California ISO Responses to Data Requests CAL-ISO-4 and CAL-ISO-7.
[2]: Positive values represent imports into the California ISO, and negative values represent exports out of the California ISO.

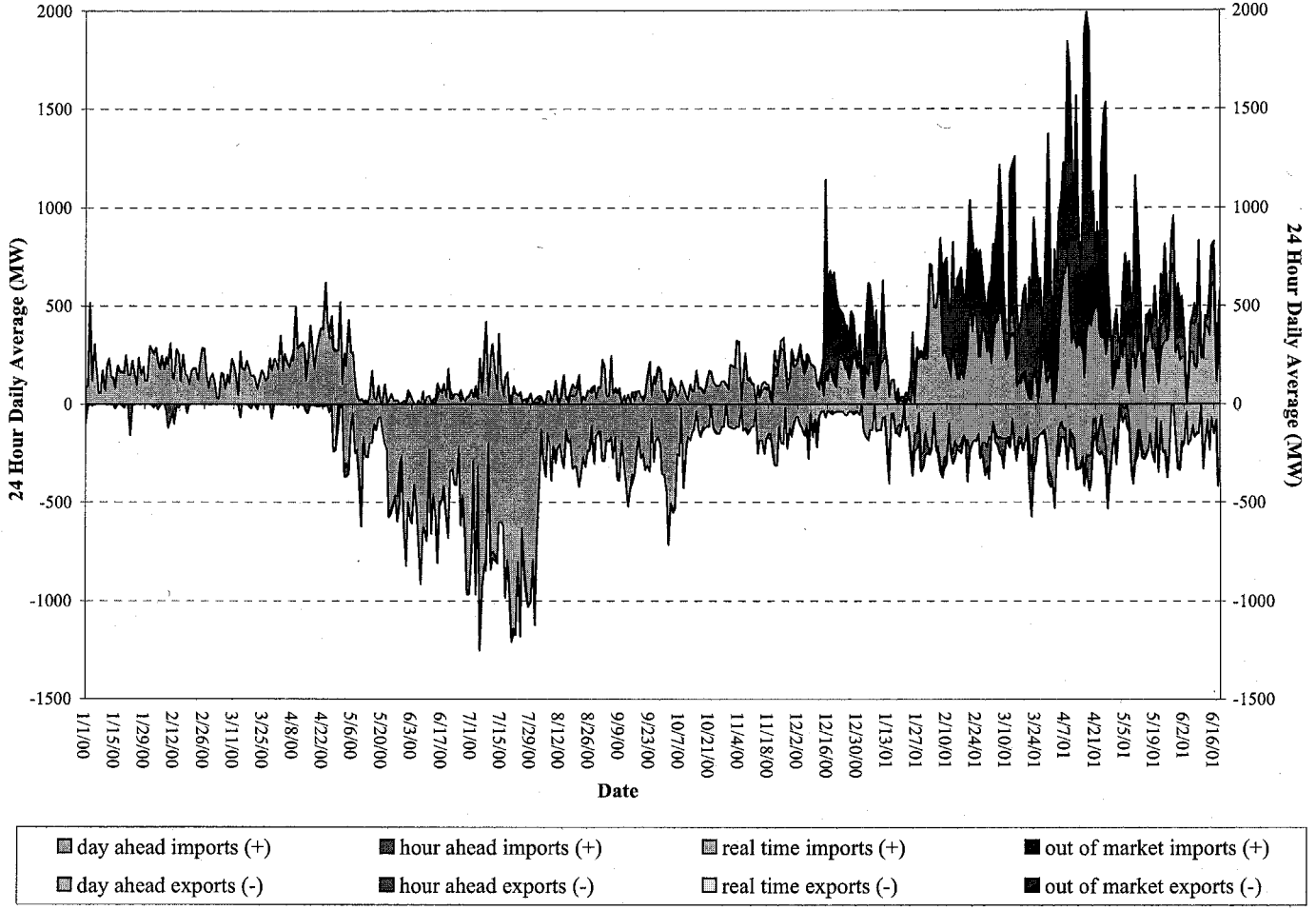
Figure C-4
A Comparison of CERS Net Imports to Everyone Else: Nov 1, 2000 to Jun 30, 2001



Source is Response to Data Requests CAL-ISO-4 and CAL-ISO-7

Contains Protected Material
Not Available to Competitive Duty Personnel

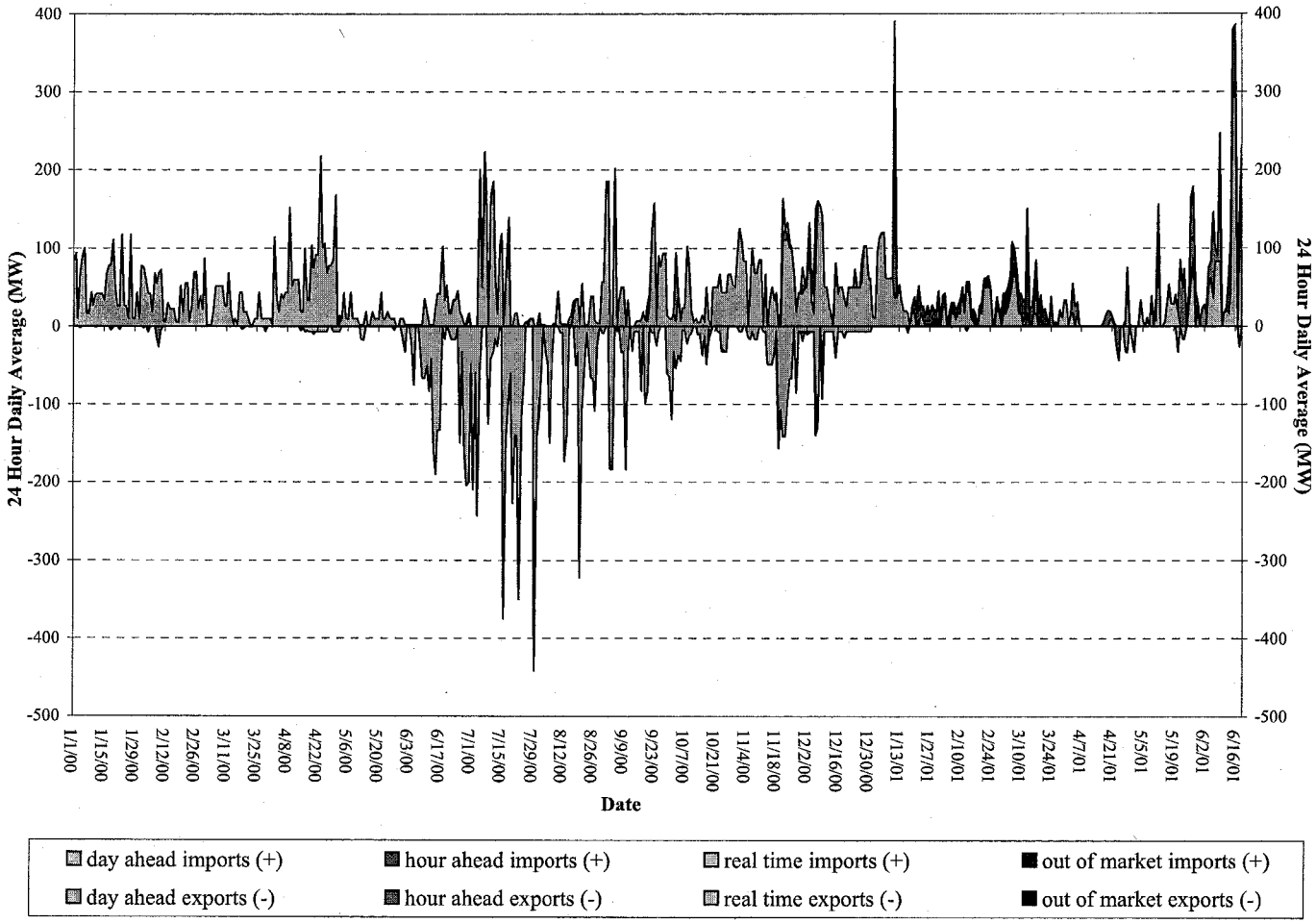
Figure C-5
Daily Average California ISO Imports and Exports
Imports and Exports of the Big Five California Generators
Jan 01, 2000 - Jun 19, 2001



Source is Response to Data Requests CAL-ISO-4 and CAL-ISO-7.

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Figure C-6
Daily Average California ISO Imports and Exports
Duke Energy Trading and Marketing Imports and Exports
Jan 01, 2000 - Jun 19, 2001

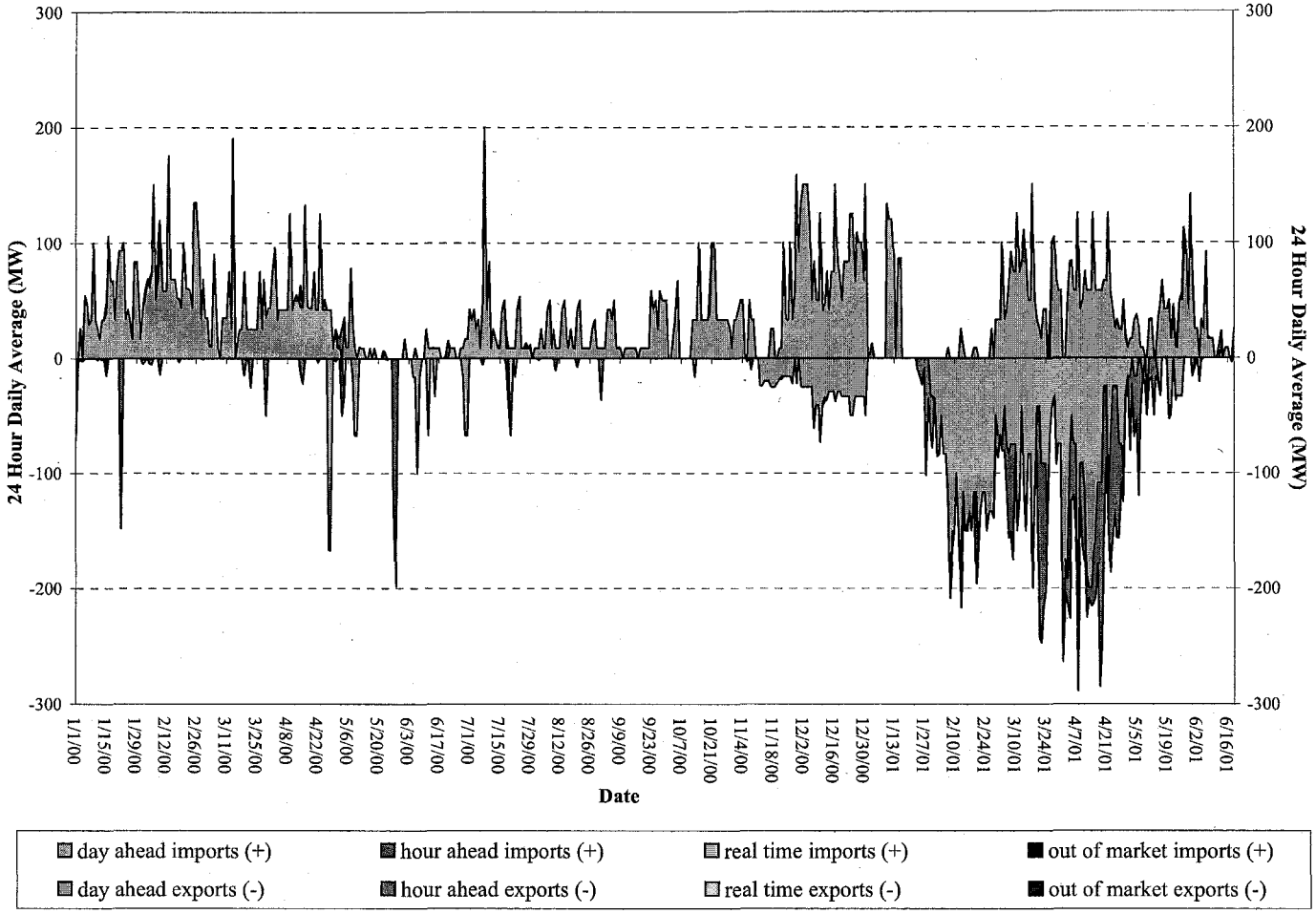


Source is Response to Data Requests CAL-ISO-4 and CAL-ISO-7.

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Contains Protected Material
Not Available to Competitive Duty Personnel

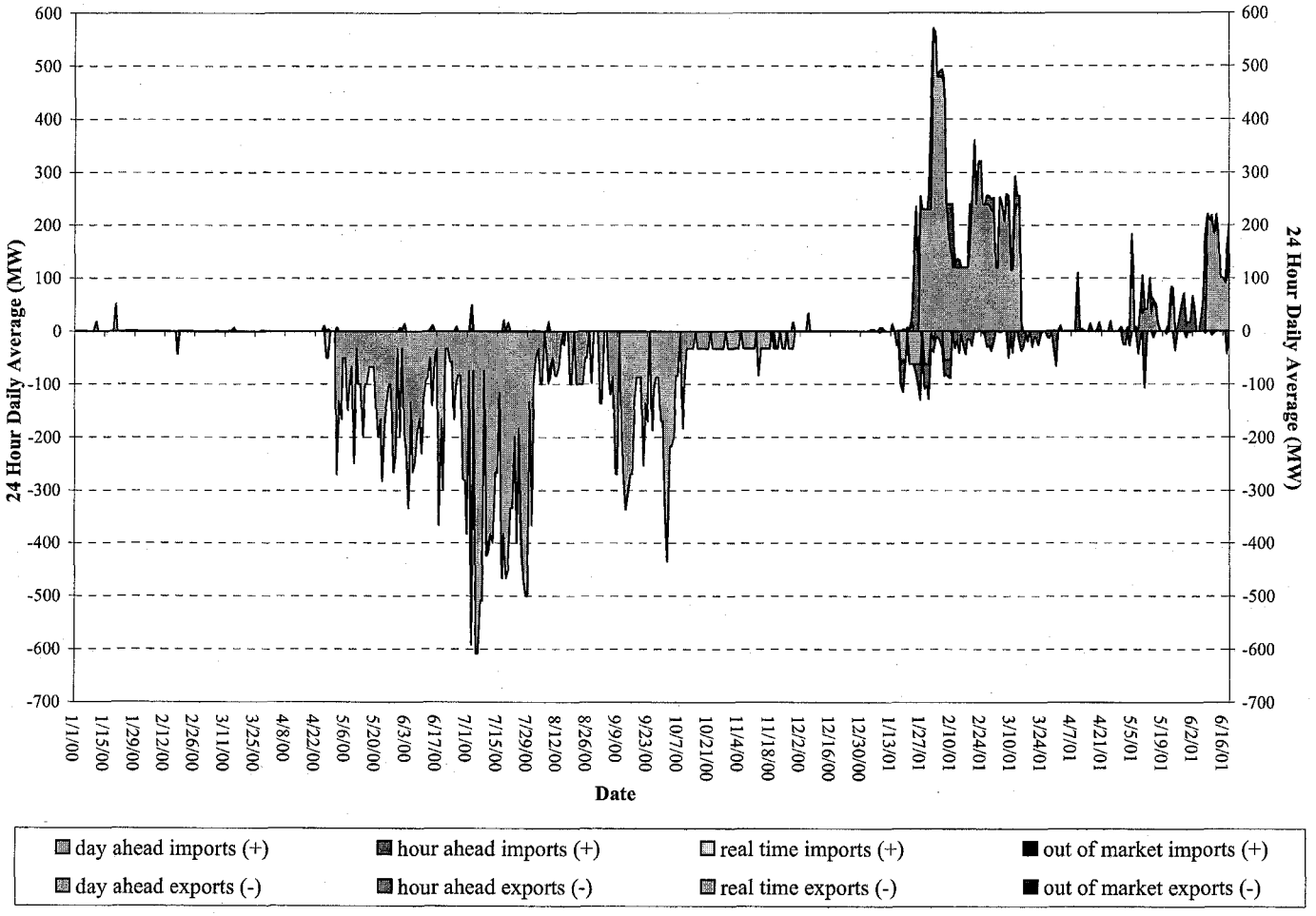
Figure C-7
Daily Average California ISO Imports and Exports
Dynegy Power Marketing Imports and Exports
Jan 01, 2000 - Jun 19, 2001



Source is Response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Contains Protected Material
Not Available to Competitive Duty Personnel

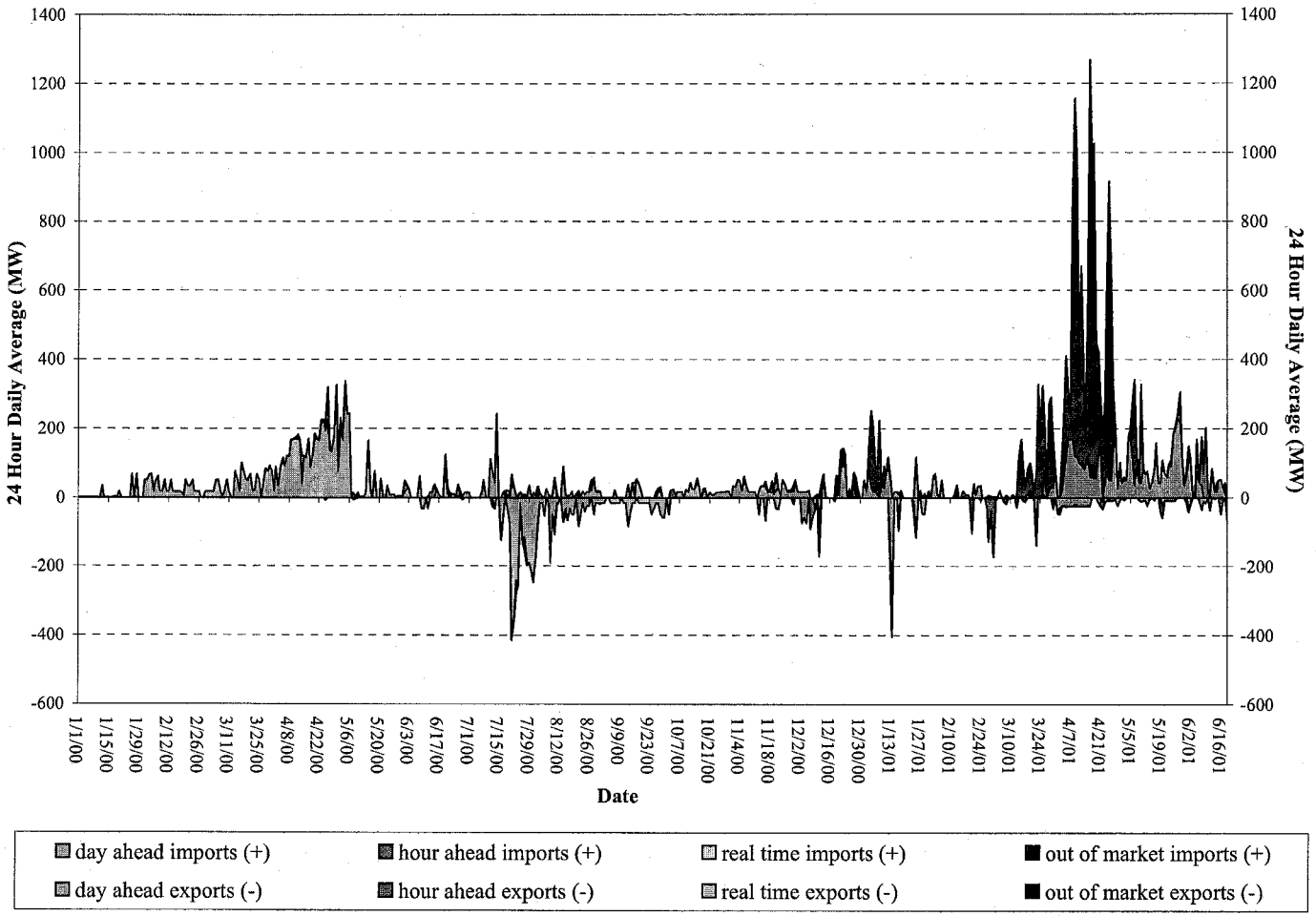
Figure C-8
Daily Average California ISO Imports and Exports
Reliant Energy Services Imports and Exports
Jan 01, 2000 - Jun 19, 2001



Source is Response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Contains Protected Material
Not Available to Competitive Duty Personnel

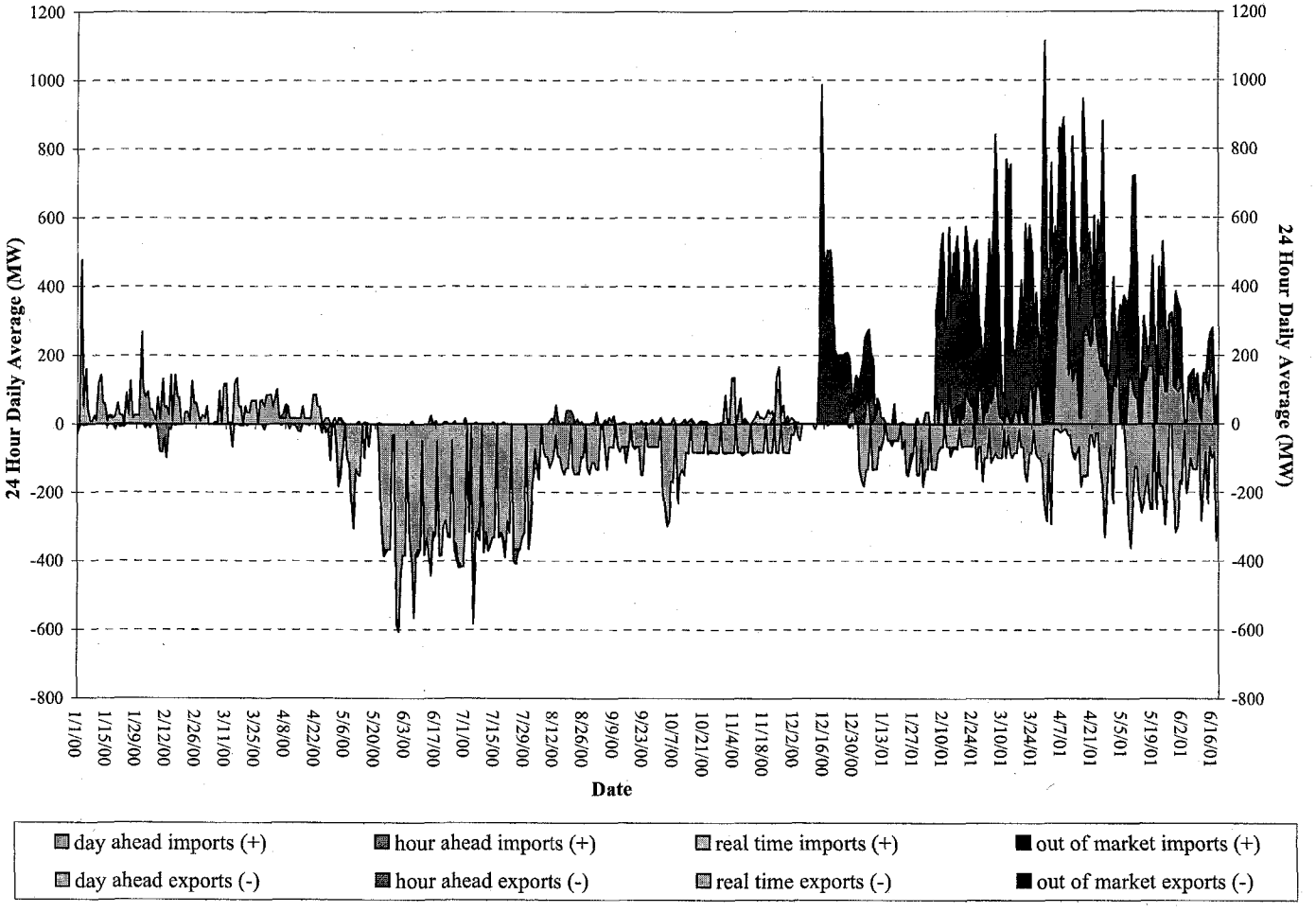
Figure C-9
Daily Average California ISO Imports and Exports
Southern Company Energy Marketing Imports and Exports
Jan 01, 2000 - Jun 19, 2001



Source is Response to Data Requests CAL-ISO-4 and CAL-ISO-7.

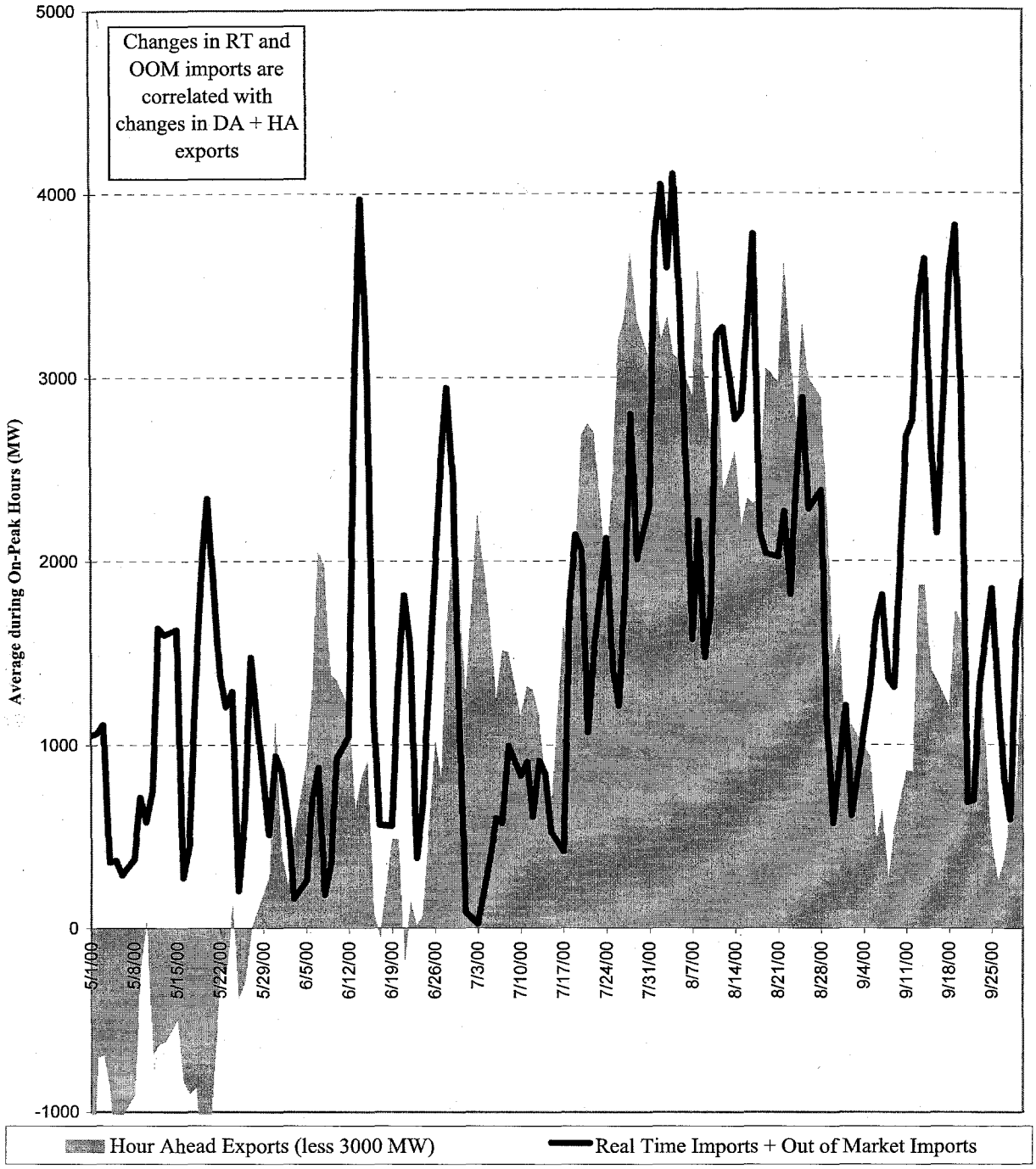
Contains Protected Material
Not Available to Competitive Duty Personnel

Figure C-10
Daily Average California ISO Imports and Exports
Williams Energy Services Imports and Exports
Jan 01, 2000 - Jun 19, 2001



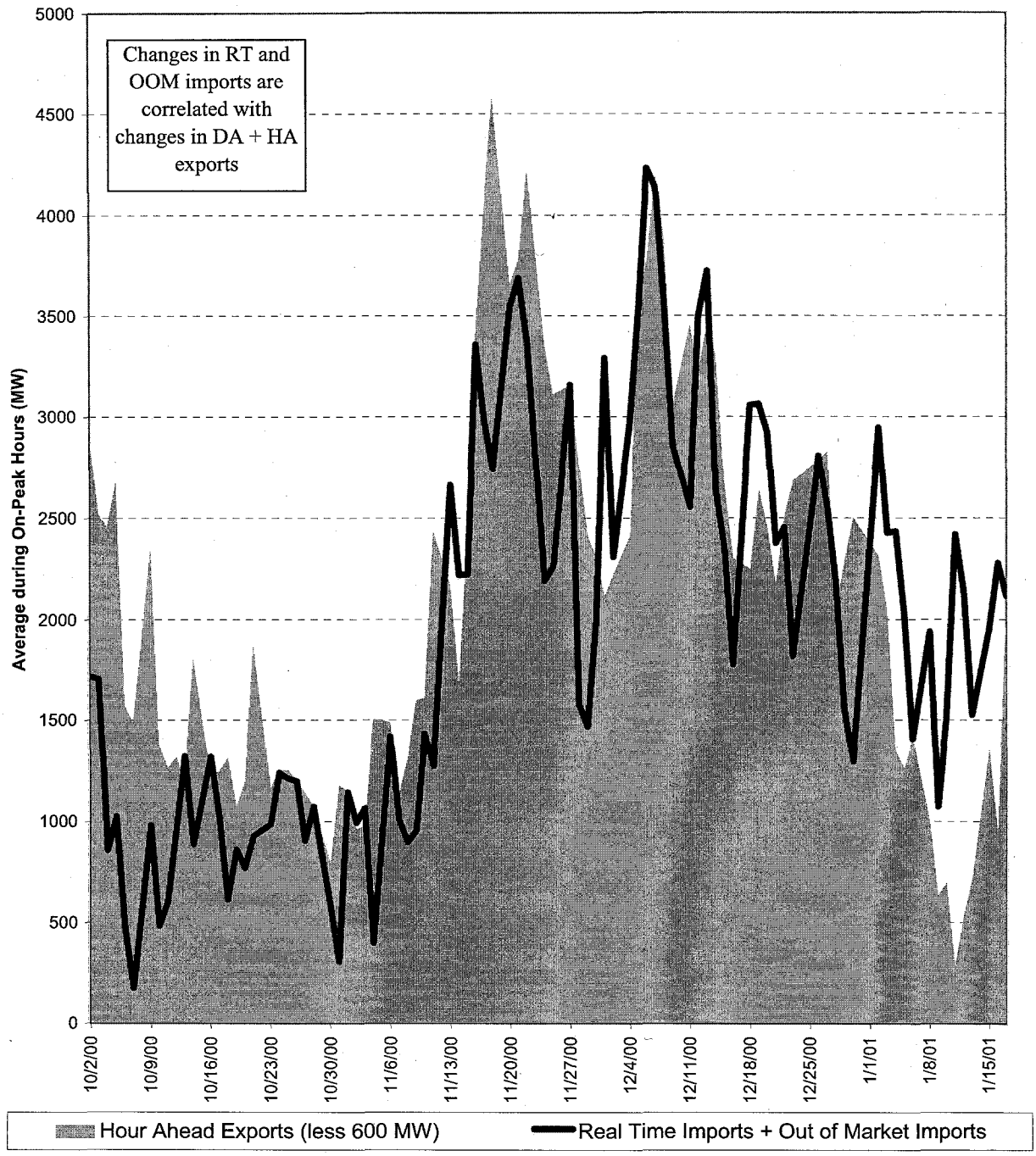
Source is Response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Figure D-1
Correlation in DA/HA Exports and RT+OOM Imports
Average Peak Hour Cal ISO DA/HA Exports and RT+OOM Imports
May 1, 2000 to October 1, 2000



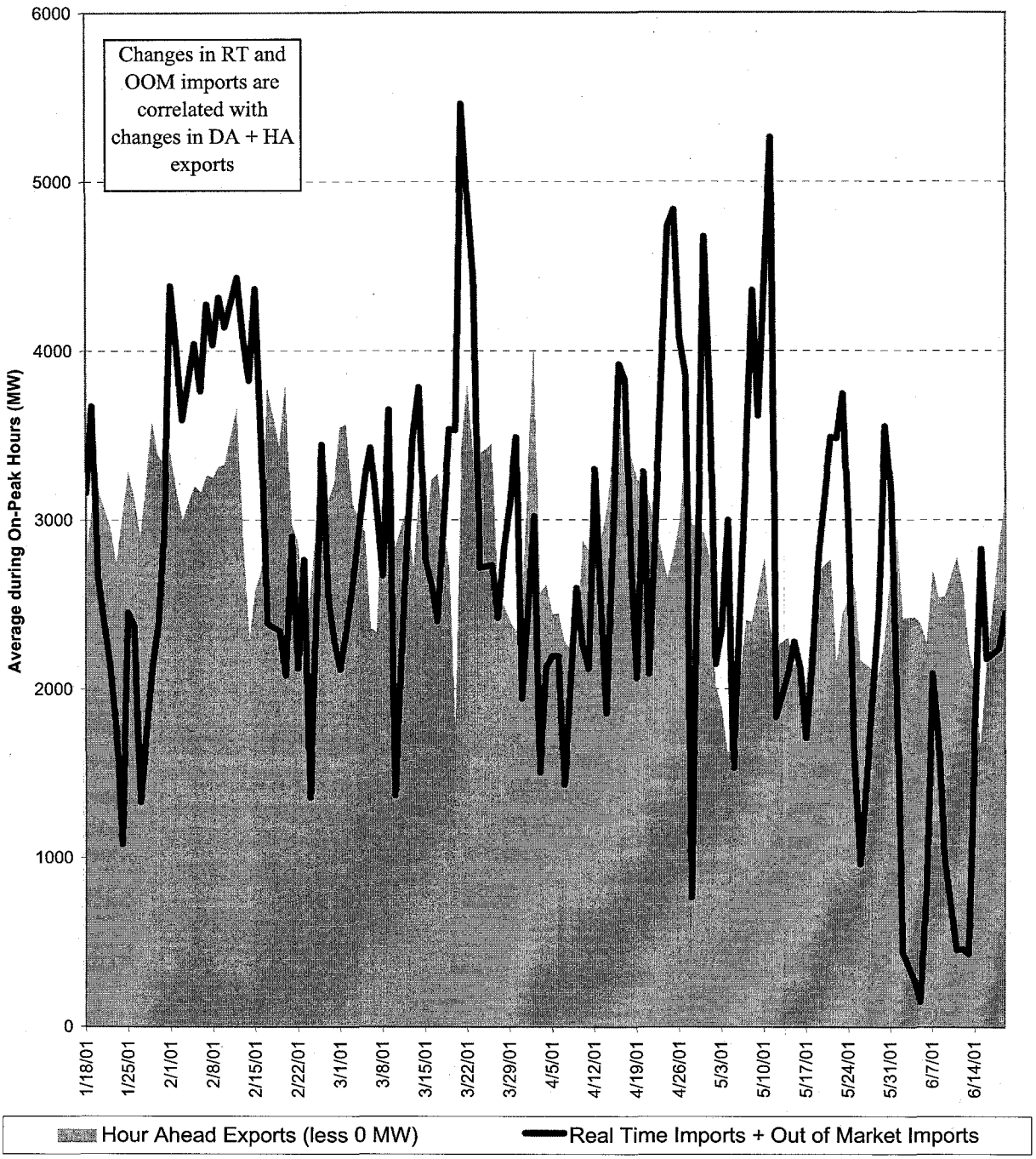
Source: Cal ISO response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Figure D-2
Correlation in DA/HA Exports and RT+OOM Imports
Average Peak Hour Cal ISO DA/HA Exports and RT+OOM Imports
October 2, 2000 to January 17, 2001



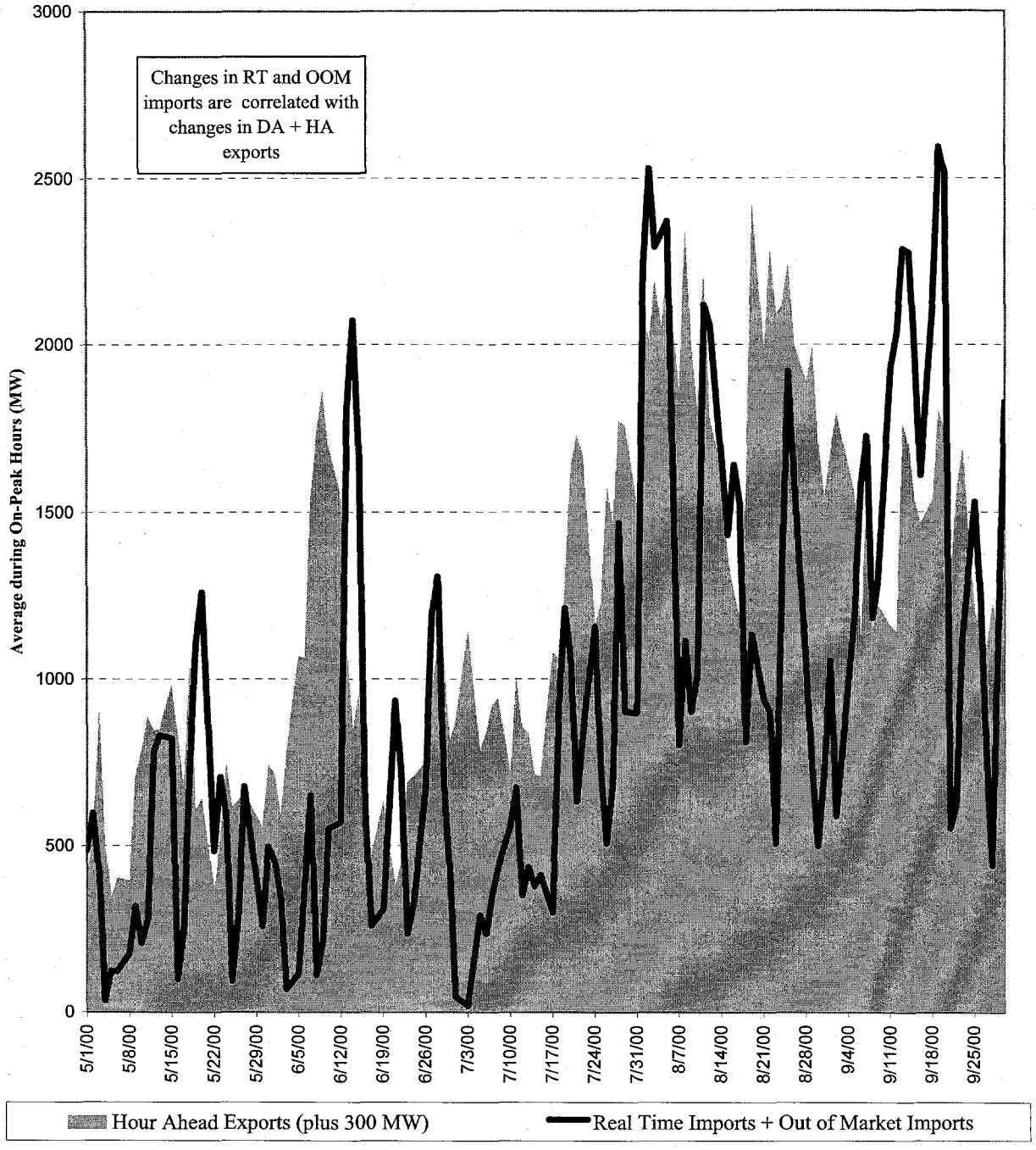
Source: Cal ISO response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Figure D-3
Correlation in DA/HA Exports and RT+OOM Imports
Average Peak Hour Cal ISO DA/HA Exports and RT+OOM Imports
January 18, 2001 to June 19, 2001



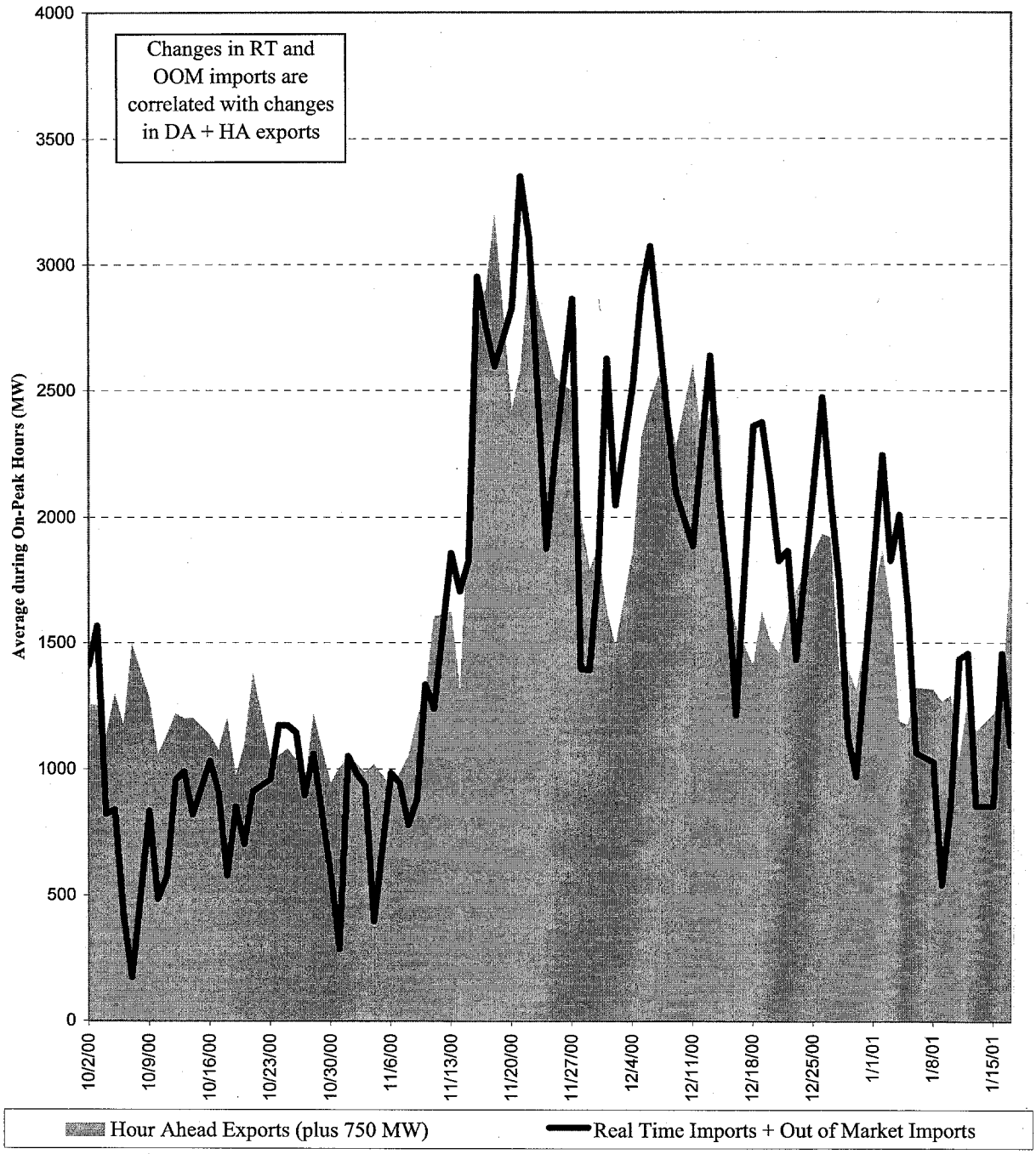
Source: Cal ISO response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Figure D-4
Correlation in DA/HA Exports and RT+OOM Imports
Average Peak Hour Cal ISO DA/HA Exports and RT+OOM Imports Between NP15 and the Northwest May 1, 2000 to Oct 1, 2000



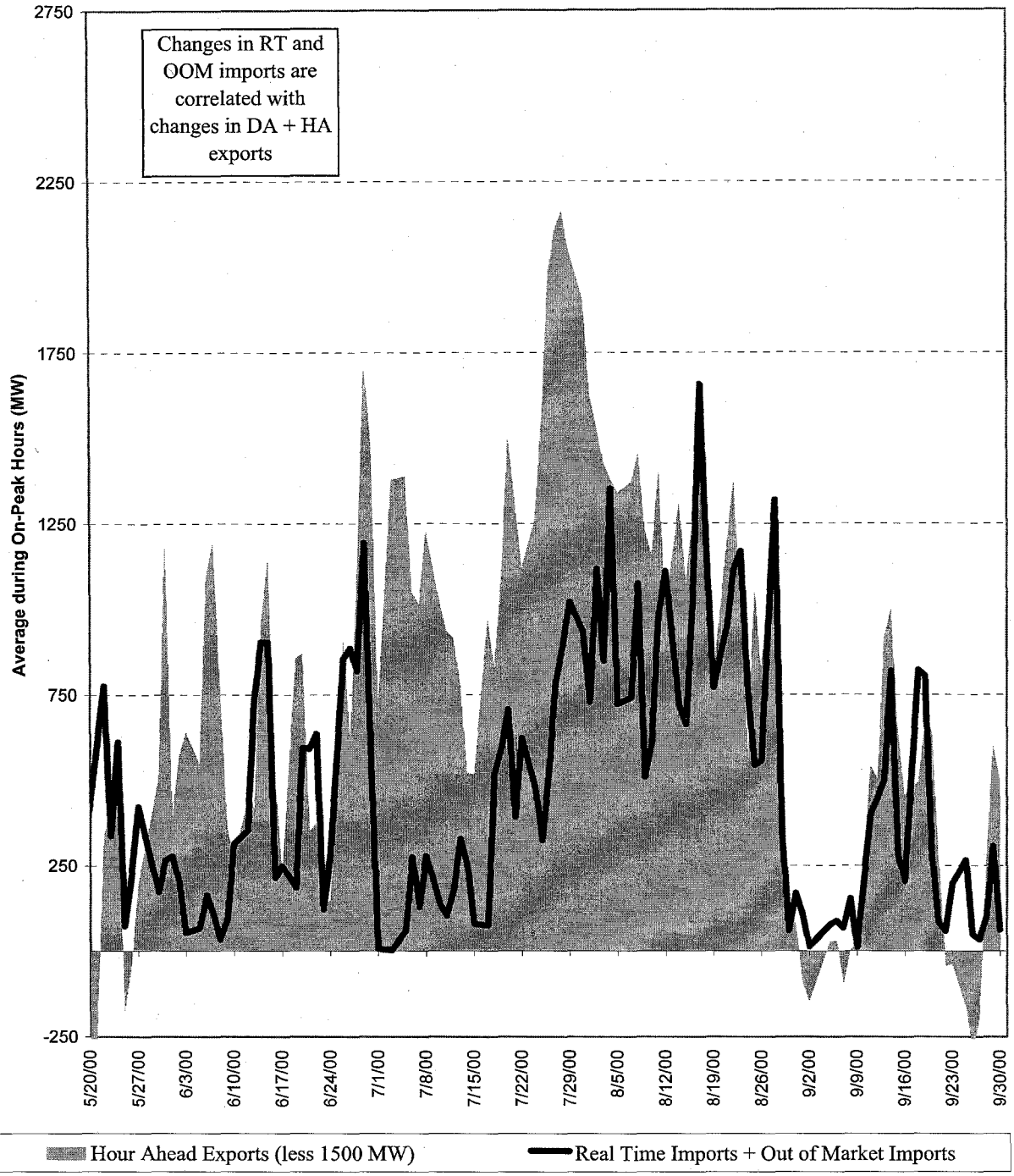
Source: Cal ISO response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Figure D-5
Correlation in DA/HA Exports and RT+OOM Imports
Average Peak Hour Cal ISO DA/HA Exports and RT+OOM Imports Between NP15 and the Northwest Oct 2, 2000 to Jan 17, 2001



Source: Cal ISO response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Figure D-6
Correlation in DA/HA Exports and RT+OOM Imports
Average Peak Hour Cal ISO DA/HA Exports and RT+OOM Imports
Between SP15 and the Southwest
May 1, 2000 to Oct 1, 2000



Source: Cal ISO response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Table D-1

Total Single Entity Exports and Imports that are Potential Ricochet Trades

Total RT plus OOM Imports Matched by DA/HA Exports In The Same Hour
May 1, 2000 through June 19, 2001

Entity	*MWh*	*Hours*	*% of Total MWh*
Powerex	806,525	4024	40%
Puget Sound Energy	275,044	1958	14%
Pacificorp	255,042	1394	13%
Williams Energy Services	192,152	1749	10%
Arizona Public Service	132,552	843	7%
Idaho Power Company	91,410	930	5%
Sempra Energy Trading	79,275	602	4%
Enron Power Marketing	45,403	793	2%
Portland General Electric	28,043	431	1%
Bonneville Power Administration	23,254	167	1%
Los Angeles Water & Power	20,904	444	1%
Aquila	16,013	396	1%
Salt River Project	9,032	147	0%
PNM	7,305	111	0%
Southern Company Energy Mktg.	5,387	131	0%
Sierra Pacific Power	4,698	82	0%
Transalta Energy Marketing	3,769	78	0%
Coral Power	2,606	132	0%
Tucson Electric Power	1,774	35	0%
City of Glendale	1,712	98	0%
Duke Energy Trading and Mktg.	968	19	0%
Modesto Irrigation District	359	15	0%
Koch Energy Trading	175	7	0%
Reliant Energy Services	150	4	0%
El Paso Power Services	146	7	0%
CDWR	120	12	0%
CFE	117	5	0%
Constellation Power Source	98	7	0%
American Electric Power	25	1	0%
Total	**2,004,056**	**14,622**	**100%**

Sources and Notes:

[1]: Sources are California ISO Responses to Data Requests CAL-ISO-4 and CAL-ISO-7.

[2]: For each Scheduling Coordinator, "RT plus OOM Imports that are matched by DA/HA Exports within an hour" is the minimum of the Scheduling Coordinators' net DA/HA exports and its net RT plus OOM imports. Hours where net DA/HA exports are less than 5 MW or net RT plus OOM imports are less than 5 MW are excluded.

[3]: Transactions scheduled by CERS after January 17, 2001, are allocated to the entity that sold energy to CERS, where possible, using interchange id codes confirmed by purchase data provided by CERS.

Table D-2
Single Entity Exports and Imports that are Potential Ricochet Trades

Total RT plus OOM Imports Matched by DA/HA Exports In The Same Hour January 1, 2000 - April 30, 2000			Total RT plus OOM Imports Matched by DA/HA Exports In The Same Hour May 1, 2000 - October 1, 2000			Total RT plus OOM Imports Matched by DA/HA Exports In The Same Hour October 2, 2000 - January 17, 2001			Total RT plus OOM Imports Matched by DA/HA Exports In The Same Hour January 18, 2001 - June 19, 2001		
Entity	*MWh*	*Hours*	*Entity*	*MWh*	*Hours*	*Entity*	*MWh*	*Hours*	*Entity*	*MWh*	*Hours*
Aquila	2,105	40	Pacificorp	221,506	1,116	Powerex	184,169	1,107	Powerex	463,734	2016
Pacificorp	1,572	18	Powerex	158,622	901	Puget Sound Energy	135,850	883	Williams Energy Services	169,852	1479
Powerex	1,261	15	Puget Sound Energy	139,194	1,075	Idaho Power Company	40,060	241	Arizona Public Service	25,459	225
Salt River Project	865	13	Arizona Public Service	99,244	531	Pacificorp	32,391	255	Sempra Energy Trading	12,157	294
Los Angeles Water & Power	263	4	Sempra Energy Trading	58,316	224	Williams Energy Services	21,060	226	Los Angeles Water & Power	9,488	330
Arizona Public Service	50	1	Idaho Power Company	51,350	689	Portland General Electric	11,022	170	Southern Company Energy Mktg.	3,684	86
Williams Energy Services	50	1	Enron Power Marketing	38,371	629	Sempra Energy Trading	8,801	84	Coral Power	1,287	42
Sempra Energy Trading	13	1	Portland General Electric	17,021	261	Arizona Public Service	7,849	87	Pacificorp	1,145	23
Modesto Irrigation District	10	1	Bonneville Power Administration	16,428	91	Enron Power Marketing	7,032	164	City of Glendale	429	21
			Aquila	16,013	396	Bonneville Power Administration	6,827	76	El Paso Power Services	146	7
			Salt River Project	7,174	119	Los Angeles Water & Power	6,770	85	Duke Energy Trading and Mktg.	38	3
			PNM	6,678	101	Transalta Energy Marketing	2,899	60			
			Los Angeles Water & Power	4,646	29	Salt River Project	1,858	28			
			Sierra Pacific Power	4,232	71	City of Glendale	1,283	77			
			Tucson Electric Power	1,774	35	Duke Energy Trading and Mktg.	930	16			
			Southern Company Energy Mktg.	1,375	38	PNM	628	10			
			Coral Power	1,319	90	Sierra Pacific Power	466	11			
			Williams Energy Services	1,240	44	Southern Company Energy Mktg.	328	7			
			Transalta Energy Marketing	869	18	CDWR	120	12			
			Modesto Irrigation District	359	15	Constellation Power Source	98	7			
			Koch Energy Trading	175	7	CFE	47	2			
			Reliant Energy Services	150	4						
			CFE	70	3						
			American Electric Power	25	1						
Total for Period	**6,188**	**94**	**Total for Period**	**846,149**	**6,488**	**Total for Period**	**470,488**	**3,608**	**Total for Period**	**687,419**	**4,526**
Total per Month	**1,534**	**23**	**Total per Month**	**164,834**	**1,264**	**Total per Month**	**130,691**	**1,002**	**Total per Month**	**134,788**	**887**

Sources and Notes:

[1]: Sources are California ISO Responses to Data Requests CAL-ISO-4 and CAL-ISO-7.

[2]: For each Scheduling Coordinator, "RT plus OOM Imports that are matched by DA/HA Exports within an hour" is the minimum of the Scheduling Coordinators' net DA/HA exports and its net RT plus OOM imports. Hours where net DA/HA exports are less than 5 MW or net RT plus OOM imports are less than 5 MW are excluded.

[3]: Transactions scheduled by CERS after January 17, 2001, are allocated to the entity that sold energy to CERS, where possible, using interchange id codes confirmed by purchase data provided by CERS.

Contains Protected Material
Not Available to Competitive Duty Personnel

Table D-3
Powerex Net Exports from the California ISO to the Northwest (MW)
During CAISO Declared Emergencies
January 1, 2000 - June 19, 2001

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
12/5/00	6	1	673	0	673
12/5/00	7	1	577	0	577
12/5/00	8	1	589	-177	412
12/5/00	9	1	591	-53	538
12/5/00	10	1	614	-321	294
12/5/00	11	1	616	-65	551
12/5/00	12	1	582	-11	571
12/5/00	13	1	547	-34	513
12/5/00	14	1	613	-25	588
12/5/00	15	1	607	0	607
12/5/00	16	1	610	0	610
12/5/00	17	2	751	0	751
12/5/00	18	2	719	0	719
12/5/00	19	2	720	0	720
12/5/00	20	2	606	0	606
12/5/00	21	2	603	0	603
12/5/00	22	1	612	0	612
12/6/00	11	2	156	0	156
12/6/00	12	2	133	0	133
12/6/00	13	2	132	0	132
12/6/00	14	2	120	0	120
12/6/00	15	2	159	0	159
12/6/00	16	2	167	0	167
12/6/00	17	2	140	0	140
12/6/00	18	2	65	0	65
12/6/00	19	2	176	0	176
12/6/00	20	2	164	0	164
12/6/00	21	2	166	0	166
12/6/00	22	2	138	0	138
12/6/00	23	1	25	0	25
12/6/00	24	1	33	0	33
12/7/00	2	1	334	0	334
12/7/00	3	1	334	0	334
12/7/00	4	1	334	0	334
12/7/00	5	2	334	0	334
12/7/00	6	2	575	0	575
12/7/00	7	2	433	0	433
12/7/00	8	2	416	0	416
12/7/00	9	2	404	0	404
12/7/00	10	2	444	0	444
12/7/00	11	2	442	0	442
12/7/00	12	2	444	0	444
12/7/00	13	2	445	0	445
12/7/00	14	2	447	0	447
12/7/00	15	2	437	0	437
12/7/00	16	2	490	0	490
12/7/00	17	2	416	0	416
12/7/00	18	3	385	0	385
12/7/00	19	3	387	0	387
12/7/00	20	3	384	0	384
12/7/00	21	2	323	0	323
12/7/00	22	2	458	0	458
12/7/00	23	2	334	0	334
12/7/00	24	2	334	0	334
12/8/00	1	2	420	0	420
12/8/00	2	2	403	0	403
12/8/00	3	2	402	0	402
12/8/00	4	2	403	0	403
12/8/00	5	2	390	0	390
12/8/00	6	2	568	0	568

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
12/8/00	7	2	397	0	397
12/8/00	8	2	529	0	529
12/8/00	9	2	511	0	511
12/8/00	10	2	502	0	502
12/8/00	11	2	468	0	468
12/8/00	12	2	684	0	684
12/8/00	13	2	664	0	664
12/8/00	14	2	682	0	682
12/8/00	15	2	674	0	674
12/8/00	16	2	676	0	676
12/8/00	17	2	469	0	469
12/8/00	18	2	465	0	465
12/8/00	19	2	478	0	478
12/8/00	20	2	471	0	471
12/8/00	21	2	478	0	478
12/8/00	22	2	442	0	442
12/8/00	23	2	158	0	158
12/8/00	24	2	152	0	152
12/9/00	11	2	146	0	146
12/9/00	12	2	146	0	146
12/9/00	13	2	158	0	158
12/9/00	14	2	158	0	158
12/9/00	15	2	175	0	175
12/9/00	16	2	193	0	193
12/9/00	17	2	5	0	5
12/9/00	18	2	0	0	0
12/9/00	19	2	7	0	7
12/9/00	20	2	0	0	0
12/9/00	21	2	20	0	20
12/9/00	22	2	33	0	33
12/10/00	16	1	82	0	82
12/11/00	12	1	0	0	0
12/11/00	13	1	0	0	0
12/11/00	18	2	51	0	51
12/11/00	19	2	61	0	61
12/11/00	23	2	36	0	36
12/12/00	1	1	457	0	457
12/12/00	2	1	456	0	456
12/12/00	3	1	456	0	456
12/12/00	4	1	455	0	455
12/12/00	5	1	456	0	456
12/12/00	6	1	9	0	9
12/12/00	9	1	6	0	6
12/12/00	10	1	6	0	6
12/12/00	11	1	411	0	411
12/12/00	12	1	412	0	412
12/12/00	13	1	412	0	412
12/12/00	14	1	411	0	411
12/12/00	15	1	408	0	408
12/12/00	16	1	457	-367	90
12/13/00	7	1	134	0	134
12/13/00	9	1	365	-67	299
12/13/00	10	1	355	0	355
12/13/00	11	1	849	0	849
12/13/00	13	1	850	-499	351
12/13/00	14	1	847	0	847
12/13/00	20	2	856	-224	633
12/13/00	21	2	880	-514	366
12/13/00	22	2	870	-476	394
12/13/00	23	1	756	0	756
12/13/00	24	1	746	-62	684
12/14/00	1	2	501	-100	401
12/14/00	2	2	501	-100	401
12/14/00	3	2	501	-100	401
12/14/00	4	2	500	-100	400

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
12/14/00	5	2	501	-100	401
12/14/00	6	2	507	-100	407
12/14/00	23	2	545	-100	445
12/14/00	24	1	510	-100	410
12/18/00	20	1	291	-171	120
12/18/00	21	1	291	-200	91
12/18/00	22	1	291	-200	91
12/18/00	23	1	336	-200	136
12/18/00	24	1	336	0	336
12/19/00	2	1	410	-200	210
12/19/00	3	1	410	-200	210
12/19/00	4	1	413	-197	216
12/19/00	5	1	439	-200	239
12/19/00	6	1	442	-200	242
12/19/00	7	1	332	-200	132
12/19/00	8	1	297	-200	97
12/19/00	9	1	257	-200	57
12/19/00	10	2	264	-200	64
12/19/00	11	2	241	-200	41
12/19/00	12	2	295	-200	95
12/19/00	13	2	291	-200	91
12/19/00	14	2	241	-200	41
12/19/00	15	2	229	-200	29
12/19/00	16	2	221	-200	21
12/19/00	17	2	256	-200	56
12/19/00	18	2	286	-127	159
12/19/00	19	2	286	-198	88
12/19/00	20	2	373	-211	162
12/19/00	21	2	277	-200	77
12/19/00	22	2	272	-200	72
12/19/00	23	2	230	-200	30
12/19/00	24	2	342	-200	142
12/20/00	10	1	283	0	283
12/20/00	11	1	262	0	262
12/20/00	12	1	196	0	196
12/20/00	13	1	220	0	220
12/20/00	14	1	108	0	108
12/20/00	15	2	206	0	206
12/20/00	16	2	191	0	191
12/20/00	17	2	178	0	178
12/20/00	18	2	86	0	86
12/20/00	21	2	77	0	77
12/20/00	22	2	174	0	174
12/20/00	23	2	621	0	621
12/20/00	24	2	540	0	540
12/21/00	1	1	303	0	303
12/21/00	2	1	303	0	303
12/21/00	3	1	303	0	303
12/21/00	4	1	303	0	303
12/21/00	5	1	303	0	303
12/21/00	7	1	52	0	52
12/21/00	12	2	115	0	115
12/21/00	13	2	115	0	115
12/21/00	14	2	183	0	183
12/21/00	15	2	118	0	118
12/21/00	16	2	170	0	170
12/21/00	17	2	97	0	97
12/21/00	21	2	77	0	77
12/21/00	22	2	126	0	126
12/21/00	23	2	100	0	100
12/21/00	24	2	100	0	100
12/23/00	1	2	101	0	101
12/23/00	2	2	196	0	196
12/23/00	3	2	321	0	321
12/23/00	4	2	346	0	346

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
12/23/00	5	2	201	0	201
12/23/00	6	2	201	0	201
12/23/00	7	2	149	33	182
12/23/00	8	2	167	0	167
12/23/00	9	2	341	0	341
12/23/00	10	2	216	0	216
12/23/00	11	2	237	0	237
12/23/00	12	2	241	0	241
12/23/00	13	2	446	0	446
12/23/00	14	2	278	0	278
12/23/00	15	2	196	0	196
12/23/00	16	2	196	0	196
12/23/00	17	2	177	0	177
12/23/00	18	2	419	0	419
12/23/00	19	2	271	0	271
12/23/00	20	2	366	0	366
12/23/00	21	2	237	0	237
12/23/00	22	2	227	0	227
12/24/00	10	1	427	0	427
12/24/00	11	1	427	0	427
12/24/00	12	1	532	0	532
12/24/00	13	1	417	0	417
12/24/00	14	1	416	0	416
12/24/00	15	1	416	0	416
12/24/00	16	1	416	0	416
12/24/00	17	1	385	0	385
12/24/00	18	1	247	0	247
12/24/00	19	1	247	0	247
12/24/00	20	1	215	0	215
12/24/00	21	1	185	0	185
12/24/00	22	1	259	0	259
1/8/01	17	1	75	0	75
1/8/01	21	1	75	0	75
1/8/01	22	1	75	0	75
1/9/01	23	2	30	0	30
1/10/01	24	2	132	0	132
1/12/01	2	3	27	0	27
1/12/01	3	3	13	0	13
1/12/01	4	2	6	0	6
1/12/01	5	2	9	0	9
1/14/01	24	2	111	0	111
1/16/01	3	2	50	0	50
1/16/01	4	2	50	0	50
1/16/01	5	2	50	0	50
1/16/01	23	3	20	0	20
1/16/01	24	3	20	0	20
1/17/01	7	3	60	0	60
1/17/01	8	3	26	0	26
1/17/01	9	3	56	0	56
1/17/01	10	3	58	0	58
1/17/01	11	3	56	0	56
1/17/01	12	3	56	0	56
1/17/01	13	3	56	0	56
1/17/01	14	3	54	0	54
1/17/01	15	3	56	0	56
1/18/01	1	3	0	0	0
1/18/01	2	3	0	0	0
1/18/01	3	3	0	0	0
1/18/01	4	3	0	0	0
1/18/01	5	3	0	0	0
1/18/01	7	3	25	0	25
1/18/01	8	3	30	0	30
1/18/01	9	3	21	0	21
1/18/01	10	3	30	0	30
1/18/01	11	3	11	0	11

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
1/18/01	12	3	11	0	11
1/18/01	13	3	11	0	11
1/18/01	14	3	11	0	11
1/18/01	15	3	11	0	11
1/18/01	16	3	11	0	11
1/18/01	17	3	11	0	11
1/18/01	18	3	11	0	11
1/18/01	19	3	11	0	11
1/18/01	20	3	11	0	11
1/18/01	21	3	11	0	11
1/18/01	22	3	11	0	11
1/19/01	7	3	18	0	18
1/19/01	8	3	61	0	61
1/19/01	9	3	43	0	43
1/19/01	10	3	49	0	49
1/19/01	11	3	56	0	56
1/19/01	12	3	49	0	49
1/19/01	13	3	49	0	49
1/19/01	14	3	46	0	46
1/19/01	15	3	47	0	47
1/19/01	16	3	47	0	47
1/19/01	17	3	53	0	53
1/19/01	18	3	45	0	45
1/19/01	19	3	16	0	16
1/19/01	20	3	6	0	6
1/19/01	21	3	64	0	64
1/19/01	22	3	49	0	49
1/20/01	7	3	93	0	93
1/20/01	8	3	93	0	93
1/20/01	11	3	93	0	93
1/20/01	12	3	93	0	93
1/20/01	13	3	93	0	93
1/20/01	14	3	93	0	93
1/20/01	15	3	93	0	93
1/20/01	16	3	93	0	93
1/20/01	17	3	93	0	93
1/20/01	18	3	110	0	110
1/20/01	19	3	118	0	118
1/20/01	20	3	112	0	112
1/20/01	21	3	105	0	105
1/20/01	22	3	97	0	97
1/21/01	1	3	25	0	25
1/21/01	2	3	25	0	25
1/21/01	3	3	25	0	25
1/21/01	4	3	25	0	25
1/21/01	5	3	25	0	25
1/21/01	10	3	25	0	25
1/21/01	11	3	25	0	25
1/21/01	12	3	25	0	25
1/21/01	13	3	25	0	25
1/21/01	14	3	25	0	25
1/21/01	15	3	25	0	25
1/21/01	16	3	25	0	25
1/21/01	17	3	25	0	25
1/21/01	18	3	0	0	0
1/21/01	19	3	0	0	0
1/21/01	20	3	0	0	0
1/21/01	21	3	0	0	0
1/22/01	6	3	115	0	115
1/22/01	7	3	126	0	126
1/22/01	8	3	126	0	126
1/22/01	9	3	124	0	124
1/22/01	10	3	151	0	151
1/22/01	11	3	139	0	139
1/22/01	12	3	153	0	153

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
1/22/01	13	3	153	0	153
1/22/01	14	3	139	0	139
1/22/01	15	3	153	0	153
1/22/01	16	3	153	0	153
1/22/01	17	3	153	0	153
1/22/01	18	3	153	0	153
1/22/01	19	3	153	0	153
1/22/01	20	3	153	0	153
1/22/01	21	3	153	0	153
1/22/01	22	3	153	0	153
1/23/01	1	3	23	0	23
1/23/01	2	3	23	0	23
1/23/01	7	3	1	0	1
1/23/01	8	3	1	0	1
1/23/01	9	3	1	0	1
1/23/01	17	3	0	0	0
1/24/01	3	3	4	0	4
1/24/01	4	3	0	0	0
1/24/01	7	3	159	0	159
1/24/01	8	3	70	0	70
1/24/01	9	3	91	0	91
1/24/01	10	3	58	0	58
1/24/01	11	3	31	0	31
1/24/01	12	3	0	0	0
1/24/01	16	3	80	0	80
1/24/01	17	3	30	0	30
1/24/01	18	3	36	0	36
1/24/01	19	3	75	0	75
1/24/01	20	3	117	0	117
1/24/01	21	3	161	0	161
1/24/01	22	3	148	0	148
1/25/01	1	3	136	0	136
1/25/01	2	3	166	0	166
1/25/01	3	3	181	0	181
1/25/01	4	3	181	0	181
1/25/01	5	3	41	0	41
1/25/01	7	3	5	0	5
1/25/01	12	3	14	0	14
1/25/01	13	3	15	0	15
1/25/01	14	3	3	0	3
1/25/01	15	3	6	0	6
1/25/01	16	3	15	0	15
1/26/01	1	3	40	0	40
1/26/01	2	3	90	0	90
1/26/01	3	3	90	0	90
1/26/01	4	3	40	0	40
1/26/01	5	3	40	0	40
1/26/01	6	3	2	0	2
1/26/01	7	3	77	0	77
1/26/01	8	3	78	0	78
1/26/01	9	3	111	0	111
1/26/01	10	3	110	0	110
1/26/01	11	3	119	0	119
1/26/01	12	3	113	0	113
1/26/01	13	3	113	0	113
1/26/01	14	3	110	0	110
1/26/01	15	3	108	0	108
1/26/01	16	3	107	0	107
1/26/01	17	3	111	0	111
1/26/01	18	3	77	0	77
1/26/01	19	3	77	0	77
1/26/01	20	3	89	0	89
1/26/01	21	3	77	0	77
1/26/01	22	3	12	0	12
1/26/01	24	3	35	0	35

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
1/27/01	1	3	125	0	125
1/27/01	2	3	125	0	125
1/27/01	3	3	125	0	125
1/27/01	4	3	125	0	125
1/27/01	5	3	100	0	100
1/27/01	7	3	47	0	47
1/27/01	8	3	47	0	47
1/27/01	9	3	100	0	100
1/27/01	10	3	97	0	97
1/27/01	11	3	105	0	105
1/27/01	12	3	105	0	105
1/27/01	13	3	97	0	97
1/27/01	14	3	94	0	94
1/27/01	15	3	94	0	94
1/27/01	16	3	94	0	94
1/27/01	17	3	47	0	47
1/27/01	18	3	47	0	47
1/27/01	19	3	47	0	47
1/27/01	20	3	97	0	97
1/27/01	21	3	39	0	39
1/27/01	22	3	39	0	39
1/27/01	23	3	50	0	50
1/27/01	24	3	50	0	50
1/28/01	1	3	50	0	50
1/28/01	2	3	50	0	50
1/28/01	3	3	50	0	50
1/28/01	4	3	50	0	50
1/28/01	5	3	50	0	50
1/28/01	6	3	28	0	28
1/28/01	7	3	30	0	30
1/28/01	8	3	9	0	9
1/28/01	9	3	50	0	50
1/28/01	10	3	50	0	50
1/28/01	11	3	50	0	50
1/28/01	12	3	50	0	50
1/28/01	13	3	50	0	50
1/28/01	14	3	50	0	50
1/28/01	15	3	50	0	50
1/28/01	16	3	50	0	50
1/28/01	17	3	25	0	25
1/28/01	18	3	25	0	25
1/28/01	19	3	72	0	72
1/28/01	20	3	72	0	72
1/28/01	21	3	72	0	72
1/28/01	22	3	65	0	65
1/28/01	23	3	50	0	50
1/28/01	24	3	50	0	50
1/29/01	1	3	50	0	50
1/29/01	2	3	49	0	49
1/29/01	3	3	50	0	50
1/29/01	4	3	50	0	50
1/29/01	5	3	50	0	50
1/29/01	6	3	48	0	48
1/29/01	7	3	50	0	50
1/29/01	8	3	55	0	55
1/29/01	9	3	49	0	49
1/29/01	10	3	49	0	49
1/29/01	11	3	53	0	53
1/29/01	12	3	58	0	58
1/29/01	13	3	58	0	58
1/29/01	14	3	58	0	58
1/29/01	15	3	58	0	58
1/29/01	16	3	58	0	58
1/29/01	17	3	59	0	59
1/29/01	18	3	70	0	70

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
1/29/01	19	3	80	0	80
1/29/01	20	3	80	0	80
1/29/01	21	3	69	0	69
1/29/01	22	3	53	0	53
1/29/01	23	3	50	0	50
1/29/01	24	3	50	0	50
1/30/01	1	3	25	0	25
1/30/01	2	3	25	0	25
1/30/01	3	3	25	0	25
1/30/01	4	3	25	0	25
1/30/01	5	3	25	0	25
1/30/01	6	3	25	0	25
1/30/01	7	3	0	0	0
1/30/01	8	3	0	0	0
1/30/01	9	3	0	0	0
1/30/01	11	3	50	0	50
1/30/01	12	3	50	0	50
1/30/01	13	3	50	0	50
1/30/01	14	3	50	0	50
1/30/01	15	3	50	0	50
1/30/01	16	3	46	0	46
1/30/01	17	3	0	0	0
1/30/01	21	3	0	0	0
1/30/01	22	3	0	0	0
1/30/01	23	3	38	0	38
1/30/01	24	3	25	0	25
1/31/01	14	3	46	0	46
1/31/01	15	3	46	0	46
1/31/01	16	3	46	0	46
2/1/01	1	3	89	0	89
2/1/01	2	3	89	0	89
2/1/01	3	3	89	0	89
2/1/01	4	3	89	0	89
2/1/01	5	3	89	0	89
2/1/01	6	3	89	0	89
2/1/01	7	3	39	0	39
2/1/01	8	3	39	0	39
2/1/01	9	3	39	0	39
2/1/01	10	3	39	0	39
2/1/01	11	3	39	0	39
2/1/01	12	3	39	0	39
2/1/01	13	3	39	0	39
2/1/01	14	3	39	0	39
2/1/01	15	3	39	0	39
2/1/01	16	3	39	0	39
2/1/01	17	3	39	0	39
2/1/01	18	3	39	0	39
2/1/01	19	3	39	0	39
2/1/01	20	3	39	0	39
2/1/01	21	3	39	0	39
2/1/01	22	3	39	0	39
2/1/01	23	3	39	0	39
2/1/01	24	3	39	0	39
2/2/01	1	3	50	0	50
2/2/01	2	3	139	0	139
2/2/01	3	3	139	0	139
2/2/01	4	3	139	0	139
2/2/01	5	3	139	0	139
2/2/01	6	3	39	0	39
2/2/01	7	3	50	0	50
2/2/01	8	3	50	0	50
2/2/01	9	3	50	0	50
2/2/01	10	3	89	0	89
2/2/01	11	3	94	0	94
2/2/01	12	3	105	0	105

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
2/2/01	13	3	94	0	94
2/2/01	14	3	105	0	105
2/2/01	15	3	100	0	100
2/2/01	16	3	100	0	100
2/2/01	17	3	139	0	139
2/2/01	18	3	175	0	175
2/2/01	19	3	175	0	175
2/2/01	20	3	225	0	225
2/2/01	21	3	214	0	214
2/2/01	22	3	164	0	164
2/2/01	23	3	114	0	114
2/2/01	24	3	114	0	114
2/3/01	1	3	159	0	159
2/3/01	2	3	209	0	209
2/3/01	3	3	292	0	292
2/3/01	4	3	292	0	292
2/3/01	5	3	292	0	292
2/3/01	6	3	292	0	292
2/3/01	7	3	261	0	261
2/3/01	8	3	261	0	261
2/3/01	9	3	261	0	261
2/3/01	10	3	267	0	267
2/3/01	11	3	170	0	170
2/3/01	12	3	170	0	170
2/3/01	13	3	170	0	170
2/3/01	14	3	266	0	266
2/3/01	15	3	170	0	170
2/3/01	16	3	170	0	170
2/3/01	17	3	170	0	170
2/3/01	18	3	270	0	270
2/3/01	19	3	287	0	287
2/3/01	20	3	281	0	281
2/3/01	21	3	275	0	275
2/3/01	22	3	266	0	266
2/3/01	23	3	305	0	305
2/3/01	24	3	292	0	292
2/4/01	1	3	288	0	288
2/4/01	2	3	288	0	288
2/4/01	3	3	438	0	438
2/4/01	4	3	438	0	438
2/4/01	5	3	438	0	438
2/4/01	6	3	438	0	438
2/4/01	7	3	438	0	438
2/4/01	8	3	438	0	438
2/4/01	9	3	513	0	513
2/4/01	10	3	513	0	513
2/4/01	11	3	413	0	413
2/4/01	12	3	413	0	413
2/4/01	13	3	413	0	413
2/4/01	14	3	413	0	413
2/4/01	15	3	413	0	413
2/4/01	16	3	413	0	413
2/4/01	17	3	413	0	413
2/4/01	18	3	413	0	413
2/4/01	19	3	413	0	413
2/4/01	20	3	413	0	413
2/4/01	21	3	413	0	413
2/4/01	22	3	413	0	413
2/4/01	23	3	413	0	413
2/4/01	24	3	538	0	538
2/5/01	1	3	513	0	513
2/5/01	2	3	438	0	438
2/5/01	3	3	438	0	438
2/5/01	4	3	438	0	438
2/5/01	5	3	438	0	438

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
2/5/01	6	3	213	0	213
2/5/01	7	3	213	0	213
2/5/01	8	3	354	0	354
2/5/01	9	3	442	0	442
2/5/01	10	3	396	0	396
2/5/01	11	3	389	0	389
2/5/01	12	3	389	0	389
2/5/01	13	3	388	0	388
2/5/01	14	3	338	0	338
2/5/01	15	3	338	0	338
2/5/01	16	3	338	0	338
2/5/01	17	3	313	0	313
2/5/01	18	3	313	0	313
2/5/01	19	3	238	0	238
2/5/01	20	3	237	0	237
2/5/01	21	3	313	0	313
2/5/01	22	3	388	0	388
2/5/01	23	3	377	0	377
2/5/01	24	3	457	0	457
2/6/01	1	3	177	0	177
2/6/01	2	3	177	0	177
2/6/01	3	3	160	0	160
2/6/01	4	3	147	0	147
2/6/01	5	3	147	0	147
2/6/01	6	3	106	0	106
2/6/01	7	3	137	0	137
2/6/01	8	3	148	0	148
2/6/01	9	3	122	0	122
2/6/01	10	3	122	0	122
2/6/01	11	3	122	0	122
2/6/01	12	3	122	0	122
2/6/01	13	3	122	0	122
2/6/01	14	3	122	0	122
2/6/01	15	3	122	0	122
2/6/01	16	3	122	0	122
2/6/01	17	3	122	0	122
2/6/01	18	3	137	0	137
2/6/01	19	3	145	0	145
2/6/01	20	3	136	0	136
2/6/01	21	3	126	0	126
2/6/01	22	3	122	0	122
2/6/01	23	3	157	0	157
2/6/01	24	3	142	0	142
2/7/01	1	3	147	0	147
2/7/01	2	3	147	0	147
2/7/01	3	3	147	0	147
2/7/01	4	3	147	0	147
2/7/01	5	3	147	0	147
2/7/01	6	3	133	0	133
2/7/01	7	3	161	0	161
2/7/01	8	3	164	0	164
2/7/01	9	3	146	0	146
2/7/01	10	3	139	0	139
2/7/01	11	3	139	0	139
2/7/01	12	3	139	0	139
2/7/01	13	3	139	0	139
2/7/01	14	3	139	0	139
2/7/01	15	3	139	0	139
2/7/01	16	3	139	0	139
2/7/01	17	3	139	0	139
2/7/01	18	3	139	0	139
2/7/01	19	3	139	0	139
2/7/01	20	3	139	0	139
2/7/01	21	3	139	0	139
2/7/01	22	3	139	0	139

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
2/7/01	23	3	139	0	139
2/7/01	24	3	139	0	139
2/8/01	1	3	59	0	59
2/8/01	2	3	59	0	59
2/8/01	3	3	59	0	59
2/8/01	4	3	59	0	59
2/8/01	5	3	59	0	59
2/8/01	6	3	59	0	59
2/8/01	7	3	59	0	59
2/8/01	8	3	59	0	59
2/8/01	9	3	59	0	59
2/8/01	10	3	59	0	59
2/8/01	11	3	59	0	59
2/8/01	12	3	59	0	59
2/8/01	13	3	122	0	122
2/8/01	14	3	59	0	59
2/8/01	15	3	59	0	59
2/8/01	16	3	59	0	59
2/8/01	17	3	59	0	59
2/8/01	18	3	59	0	59
2/8/01	19	3	59	0	59
2/8/01	20	3	59	0	59
2/8/01	21	3	59	0	59
2/8/01	22	3	59	0	59
2/8/01	23	3	59	0	59
2/8/01	24	3	59	0	59
2/9/01	1	3	111	0	111
2/9/01	2	3	111	0	111
2/9/01	3	3	111	0	111
2/9/01	4	3	111	0	111
2/9/01	5	3	111	0	111
2/9/01	6	3	111	0	111
2/9/01	7	3	146	0	146
2/9/01	8	3	156	0	156
2/9/01	9	3	131	0	131
2/9/01	10	3	131	0	131
2/9/01	11	3	131	0	131
2/9/01	12	3	131	0	131
2/9/01	13	3	131	0	131
2/9/01	14	3	131	0	131
2/9/01	15	3	131	0	131
2/9/01	16	3	131	0	131
2/9/01	17	3	131	0	131
2/9/01	18	3	115	0	115
2/9/01	19	3	147	0	147
2/9/01	20	3	140	0	140
2/9/01	21	3	136	0	136
2/9/01	22	3	136	0	136
2/9/01	23	3	130	0	130
2/9/01	24	3	111	0	111
2/10/01	1	3	111	0	111
2/10/01	2	3	111	0	111
2/10/01	3	3	111	0	111
2/10/01	4	3	111	0	111
2/10/01	5	3	111	0	111
2/10/01	6	3	111	0	111
2/10/01	7	3	111	0	111
2/10/01	8	3	111	0	111
2/10/01	9	3	115	0	115
2/10/01	10	3	116	0	116
2/10/01	11	3	119	0	119
2/10/01	12	3	116	0	116
2/10/01	13	3	116	0	116
2/10/01	14	3	114	0	114
2/10/01	15	3	111	0	111

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
2/10/01	16	3	111	0	111
2/10/01	17	3	113	0	113
2/10/01	18	3	135	0	135
2/10/01	19	3	137	0	137
2/10/01	20	3	137	0	137
2/10/01	21	3	130	0	130
2/10/01	22	3	127	0	127
2/10/01	23	3	126	0	126
2/10/01	24	3	111	0	111
2/11/01	1	3	61	0	61
2/11/01	2	3	61	0	61
2/11/01	3	3	61	0	61
2/11/01	4	3	61	0	61
2/11/01	5	3	61	0	61
2/11/01	6	3	61	0	61
2/11/01	7	3	61	0	61
2/11/01	8	3	61	0	61
2/11/01	9	3	61	0	61
2/11/01	10	3	61	0	61
2/11/01	11	3	61	0	61
2/11/01	12	3	61	0	61
2/11/01	13	3	61	0	61
2/11/01	14	3	61	0	61
2/11/01	15	3	61	0	61
2/11/01	16	3	64	0	64
2/11/01	17	3	66	0	66
2/11/01	18	3	88	0	88
2/11/01	19	3	92	0	92
2/11/01	20	3	92	0	92
2/11/01	21	3	90	0	90
2/11/01	22	3	77	0	77
2/11/01	23	3	61	0	61
2/11/01	24	3	61	0	61
2/12/01	1	3	61	0	61
2/12/01	2	3	61	0	61
2/12/01	3	3	61	0	61
2/12/01	4	3	61	0	61
2/12/01	5	3	61	0	61
2/12/01	6	3	61	0	61
2/12/01	7	3	41	0	41
2/12/01	8	3	46	0	46
2/12/01	9	3	39	0	39
2/12/01	10	3	39	0	39
2/12/01	11	3	39	0	39
2/12/01	12	3	39	0	39
2/12/01	13	3	39	0	39
2/12/01	14	3	39	0	39
2/12/01	15	3	39	0	39
2/12/01	16	3	39	0	39
2/12/01	17	3	39	0	39
2/12/01	18	3	52	0	52
2/12/01	19	3	56	0	56
2/12/01	20	3	51	0	51
2/12/01	21	3	43	0	43
2/12/01	22	3	39	0	39
2/12/01	23	3	80	0	80
2/12/01	24	3	61	0	61
2/13/01	1	3	64	0	64
2/13/01	2	3	64	0	64
2/13/01	3	3	89	0	89
2/13/01	4	3	89	0	89
2/13/01	5	3	89	0	89
2/13/01	6	3	39	0	39
2/13/01	7	3	109	0	109
2/13/01	8	3	109	0	109

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
2/13/01	9	3	109	0	109
2/13/01	10	3	109	0	109
2/13/01	11	3	109	0	109
2/13/01	12	3	109	0	109
2/13/01	13	3	109	0	109
2/13/01	14	3	109	0	109
2/13/01	15	3	109	0	109
2/13/01	16	3	109	0	109
2/13/01	17	3	109	0	109
2/13/01	18	3	109	0	109
2/13/01	19	3	109	0	109
2/13/01	20	3	109	0	109
2/13/01	21	3	109	0	109
2/13/01	22	3	109	0	109
2/13/01	23	3	39	0	39
2/13/01	24	3	39	0	39
2/14/01	1	3	225	0	225
2/14/01	2	3	225	0	225
2/14/01	3	3	225	0	225
2/14/01	4	3	225	0	225
2/14/01	5	3	225	0	225
2/14/01	6	3	225	0	225
2/14/01	7	3	175	0	175
2/14/01	8	3	175	0	175
2/14/01	9	3	175	0	175
2/14/01	10	3	175	0	175
2/14/01	11	3	175	0	175
2/14/01	12	3	175	0	175
2/14/01	13	3	175	0	175
2/14/01	14	3	175	0	175
2/14/01	15	3	175	0	175
2/14/01	16	3	175	0	175
2/14/01	17	3	175	0	175
2/14/01	18	3	175	0	175
2/14/01	19	3	175	0	175
2/14/01	20	3	125	0	125
2/14/01	21	3	175	0	175
2/14/01	22	3	175	0	175
2/14/01	23	3	225	0	225
2/14/01	24	3	225	0	225
2/15/01	1	3	235	0	235
2/15/01	2	3	251	0	251
2/15/01	3	3	251	0	251
2/15/01	4	3	251	0	251
2/15/01	5	3	251	0	251
2/15/01	6	3	215	0	215
2/15/01	7	3	250	0	250
2/15/01	8	3	250	0	250
2/15/01	9	3	250	0	250
2/15/01	10	3	250	0	250
2/15/01	11	3	250	0	250
2/15/01	12	3	250	0	250
2/15/01	13	3	250	0	250
2/15/01	14	3	250	0	250
2/15/01	15	3	250	0	250
2/15/01	16	3	250	0	250
2/15/01	17	3	250	0	250
2/15/01	18	3	250	0	250
2/15/01	19	3	250	0	250
2/15/01	20	3	250	0	250
2/15/01	21	3	250	0	250
2/15/01	22	3	250	0	250
2/15/01	23	3	269	0	269
2/15/01	24	3	251	0	251
2/16/01	1	3	185	0	185

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
2/16/01	2	3	161	0	161
2/16/01	3	3	158	0	158
2/16/01	4	3	168	0	168
2/16/01	5	3	153	0	153
2/16/01	6	3	129	0	129
2/16/01	7	3	274	0	274
2/16/01	8	3	274	0	274
2/16/01	9	3	274	0	274
2/16/01	10	3	274	0	274
2/16/01	11	3	274	0	274
2/16/01	12	3	274	0	274
2/16/01	13	3	274	0	274
2/16/01	14	3	274	0	274
2/16/01	15	3	274	0	274
2/16/01	16	3	274	0	274
2/16/01	17	3	274	0	274
2/16/01	18	3	274	0	274
2/16/01	19	3	274	0	274
2/16/01	20	3	274	0	274
2/16/01	21	3	274	0	274
2/16/01	22	3	274	0	274
2/16/01	23	3	260	0	260
2/16/01	24	3	236	0	236
2/17/01	1	2	159	0	159
2/17/01	2	2	184	0	184
2/17/01	3	2	184	0	184
2/17/01	4	2	184	0	184
2/17/01	5	2	184	0	184
2/17/01	6	2	134	0	134
2/17/01	7	2	234	0	234
2/17/01	8	2	234	0	234
2/17/01	9	2	209	0	209
2/17/01	10	2	209	0	209
2/17/01	11	2	159	0	159
2/17/01	12	2	159	0	159
2/17/01	13	2	159	0	159
2/17/01	14	2	234	0	234
2/17/01	15	2	259	0	259
2/17/01	16	2	309	0	309
2/17/01	17	2	259	0	259
2/17/01	18	2	159	0	159
2/17/01	19	2	159	0	159
2/17/01	20	2	159	0	159
2/17/01	21	2	159	0	159
2/17/01	22	2	209	0	209
2/17/01	23	2	184	0	184
2/17/01	24	2	184	0	184
2/18/01	1	2	247	0	247
2/18/01	2	2	247	0	247
2/18/01	3	2	247	0	247
2/18/01	4	2	247	0	247
2/18/01	5	2	247	0	247
2/18/01	6	2	247	0	247
2/18/01	7	2	158	0	158
2/18/01	8	2	158	0	158
2/18/01	9	2	158	0	158
2/18/01	10	2	160	0	160
2/18/01	11	2	158	0	158
2/18/01	12	2	158	0	158
2/18/01	13	2	158	0	158
2/18/01	14	2	158	0	158
2/18/01	15	2	158	0	158
2/18/01	16	2	158	0	158
2/18/01	17	2	163	0	163
2/18/01	18	2	189	0	189

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
2/18/01	19	2	189	0	189
2/18/01	20	2	189	0	189
2/18/01	21	2	189	0	189
2/18/01	22	2	174	0	174
2/18/01	23	2	247	0	247
2/18/01	24	2	247	0	247
2/19/01	1	2	252	0	252
2/19/01	2	2	252	0	252
2/19/01	3	2	252	0	252
2/19/01	4	2	252	0	252
2/19/01	5	2	252	0	252
2/19/01	6	2	252	0	252
2/19/01	7	2	396	0	396
2/19/01	8	2	404	0	404
2/19/01	9	2	381	0	381
2/19/01	10	2	381	0	381
2/19/01	11	2	381	0	381
2/19/01	12	2	381	0	381
2/19/01	13	2	381	0	381
2/19/01	14	2	381	0	381
2/19/01	15	2	381	0	381
2/19/01	16	2	381	0	381
2/19/01	17	2	396	0	396
2/19/01	18	2	396	0	396
2/19/01	19	2	245	0	245
2/19/01	20	2	239	0	239
2/19/01	21	2	230	0	230
2/19/01	22	2	225	0	225
2/19/01	23	2	118	0	118
2/19/01	24	2	118	0	118
2/20/01	1	2	252	0	252
2/20/01	2	2	252	0	252
2/20/01	3	2	252	0	252
2/20/01	4	2	252	0	252
2/20/01	5	2	252	0	252
2/20/01	6	2	252	0	252
2/20/01	7	2	396	0	396
2/20/01	8	2	406	0	406
2/20/01	9	2	381	0	381
2/20/01	10	2	381	0	381
2/20/01	11	2	381	0	381
2/20/01	12	2	381	0	381
2/20/01	13	2	381	0	381
2/20/01	14	2	381	0	381
2/20/01	15	2	381	0	381
2/20/01	16	2	381	0	381
2/20/01	17	2	381	0	381
2/20/01	18	2	389	0	389
2/20/01	19	2	402	0	402
2/20/01	20	2	395	0	395
2/20/01	21	2	387	0	387
2/20/01	22	2	381	0	381
2/20/01	23	2	267	0	267
2/20/01	24	2	246	0	246
2/21/01	1	2	361	0	361
2/21/01	2	2	148	0	148
2/21/01	3	2	145	0	145
2/21/01	4	2	146	0	146
2/21/01	5	2	148	0	148
2/21/01	6	2	251	0	251
2/21/01	7	2	393	0	393
2/21/01	8	2	393	0	393
2/21/01	9	2	393	0	393
2/21/01	10	2	393	0	393
2/21/01	11	2	393	0	393

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
2/21/01	12	2	393	0	393
2/21/01	13	2	393	0	393
2/21/01	14	2	393	0	393
2/21/01	15	2	393	0	393
2/21/01	16	2	411	0	411
2/21/01	17	2	411	0	411
2/21/01	18	2	421	0	421
2/21/01	19	2	369	0	369
2/21/01	20	2	368	0	368
2/21/01	21	2	369	0	369
2/21/01	22	2	393	0	393
2/21/01	23	2	380	0	380
2/21/01	24	2	361	0	361
2/22/01	1	2	255	0	255
2/22/01	2	2	255	0	255
2/22/01	3	2	255	0	255
2/22/01	4	2	255	0	255
2/22/01	5	2	255	0	255
2/22/01	6	2	256	0	256
2/22/01	7	2	400	0	400
2/22/01	8	2	400	0	400
2/22/01	9	2	400	0	400
2/28/01	11	2	332	0	332
2/28/01	12	2	350	0	350
2/28/01	13	2	367	0	367
2/28/01	14	2	358	0	358
2/28/01	15	2	358	0	358
2/28/01	16	2	360	0	360
2/28/01	17	2	340	0	340
2/28/01	18	2	337	0	337
2/28/01	19	2	337	0	337
2/28/01	20	2	337	0	337
2/28/01	21	2	337	0	337
2/28/01	22	2	366	0	366
2/28/01	23	2	315	0	315
2/28/01	24	2	297	0	297
3/1/01	7	2	51	0	51
3/1/01	8	2	51	0	51
3/1/01	9	2	51	0	51
3/1/01	10	2	51	0	51
3/5/01	9	2	119	0	119
3/5/01	10	2	119	0	119
3/5/01	11	2	119	0	119
3/5/01	12	2	119	0	119
3/5/01	13	2	119	0	119
3/5/01	14	2	119	0	119
3/5/01	15	2	119	0	119
3/5/01	16	2	119	0	119
3/5/01	17	2	119	0	119
3/5/01	18	2	125	0	125
3/5/01	19	2	138	0	138
3/5/01	20	2	133	0	133
3/5/01	21	2	124	0	124
3/5/01	22	2	119	0	119
3/5/01	23	2	128	0	128
3/5/01	24	2	113	0	113
3/15/01	11	2	225	0	225
3/15/01	12	2	225	0	225
3/15/01	13	2	225	0	225
3/15/01	14	2	225	0	225
3/15/01	15	2	225	0	225
3/15/01	16	2	225	0	225
3/15/01	17	2	225	0	225
3/15/01	18	2	225	0	225
3/15/01	19	2	225	0	225

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
3/15/01	20	2	225	0	225
3/15/01	21	2	225	0	225
3/15/01	22	2	225	0	225
3/19/01	7	2	346	0	346
3/19/01	8	2	357	0	357
3/19/01	9	2	341	0	341
3/19/01	10	2	341	0	341
3/19/01	11	2	341	0	341
3/19/01	12	3	341	0	341
3/19/01	13	3	345	0	345
3/19/01	14	3	345	0	345
3/19/01	15	3	345	0	345
3/19/01	16	3	345	0	345
3/19/01	17	3	345	0	345
3/19/01	18	3	257	0	257
3/19/01	19	3	272	0	272
3/19/01	20	3	277	0	277
3/19/01	21	3	273	0	273
3/19/01	22	2	257	0	257
3/19/01	23	2	230	0	230
3/19/01	24	2	228	0	228
3/20/01	1	2	137	0	137
3/20/01	2	2	137	0	137
3/20/01	3	2	137	0	137
3/20/01	4	2	137	0	137
3/20/01	5	2	137	0	137
3/20/01	6	2	137	0	137
3/20/01	7	2	225	0	225
3/20/01	8	2	225	0	225
3/20/01	9	2	225	0	225
3/20/01	10	3	225	0	225
3/20/01	11	3	225	0	225
3/20/01	12	3	225	0	225
3/20/01	13	3	225	0	225
3/20/01	14	3	225	0	225
3/20/01	15	3	225	0	225
3/20/01	16	2	225	0	225
3/20/01	17	2	225	0	225
3/20/01	18	2	225	0	225
3/20/01	19	2	225	0	225
3/20/01	20	2	225	0	225
3/20/01	21	2	225	0	225
3/20/01	22	2	225	0	225
3/21/01	7	2	83	0	83
3/21/01	8	2	83	0	83
3/21/01	9	2	83	0	83
3/21/01	10	2	88	0	88
3/21/01	11	2	138	0	138
3/21/01	12	2	90	0	90
3/21/01	13	2	89	0	89
3/21/01	14	2	83	0	83
3/21/01	15	2	83	0	83
3/21/01	16	2	84	0	84
3/21/01	17	2	95	0	95
3/21/01	18	2	101	0	101
3/21/01	19	2	87	0	87
3/21/01	20	2	91	0	91
3/21/01	21	2	104	0	104
3/21/01	22	2	116	0	116
3/21/01	23	2	62	0	62
3/27/01	14	2	309	0	309
3/27/01	15	2	309	0	309
3/27/01	16	2	309	0	309
3/27/01	17	2	309	0	309
3/27/01	18	2	309	0	309

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
3/27/01	19	2	300	0	300
3/27/01	20	2	300	0	300
3/27/01	21	2	300	0	300
3/27/01	22	2	300	0	300
3/28/01	11	2	396	0	396
3/28/01	12	2	396	0	396
3/28/01	13	2	401	0	401
3/28/01	14	2	401	0	401
3/28/01	15	2	401	0	401
3/28/01	16	2	394	0	394
3/28/01	17	2	396	0	396
3/28/01	18	2	396	0	396
3/28/01	19	2	400	0	400
3/28/01	20	2	400	0	400
3/28/01	21	2	396	0	396
3/28/01	22	2	396	0	396
3/28/01	23	2	536	0	536
3/28/01	24	2	424	0	424
3/29/01	11	2	434	0	434
3/29/01	12	2	434	0	434
3/29/01	13	2	434	0	434
3/29/01	14	2	428	0	428
3/29/01	15	2	428	0	428
3/29/01	16	2	421	0	421
3/29/01	17	2	413	0	413
3/29/01	18	2	434	0	434
3/29/01	19	2	425	0	425
3/29/01	20	2	351	0	351
3/29/01	21	2	425	0	425
3/29/01	22	2	425	0	425
3/29/01	23	2	179	0	179
3/29/01	24	2	58	0	58
3/30/01	10	2	239	0	239
3/30/01	11	2	239	0	239
3/30/01	12	2	239	0	239
3/30/01	13	2	239	0	239
3/30/01	14	2	239	0	239
3/30/01	15	2	239	0	239
3/30/01	16	2	239	0	239
3/30/01	17	2	239	0	239
3/30/01	18	2	239	0	239
3/30/01	19	2	239	0	239
3/30/01	20	2	239	0	239
3/30/01	21	2	239	0	239
3/30/01	22	2	239	0	239
3/30/01	23	2	329	0	329
3/30/01	24	2	224	0	224
3/31/01	12	2	239	0	239
3/31/01	13	2	239	0	239
3/31/01	14	2	239	0	239
3/31/01	15	2	239	0	239
3/31/01	16	2	239	0	239
3/31/01	17	2	239	0	239
3/31/01	18	2	239	0	239
3/31/01	19	2	239	0	239
3/31/01	20	2	239	0	239
4/2/01	9	2	145	0	145
4/2/01	10	2	209	0	209
4/2/01	11	2	222	0	222
4/2/01	12	2	184	0	184
4/2/01	13	2	203	0	203
4/2/01	14	2	207	0	207
4/2/01	15	2	207	0	207
4/2/01	16	2	207	0	207
4/2/01	17	2	207	0	207

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
4/2/01	18	2	197	0	197
4/2/01	19	2	224	0	224
4/2/01	20	2	254	0	254
4/2/01	21	2	272	0	272
4/2/01	22	2	269	0	269
4/2/01	23	2	155	0	155
4/2/01	24	2	105	0	105
4/3/01	1	2	30	0	30
4/3/01	2	2	30	0	30
4/3/01	3	2	30	0	30
4/3/01	4	2	30	0	30
4/3/01	5	2	30	0	30
4/3/01	6	2	30	0	30
4/3/01	7	2	117	0	117
4/3/01	8	2	200	0	200
4/3/01	9	2	200	0	200
4/3/01	10	2	200	0	200
4/3/01	11	2	198	0	198
4/3/01	12	2	175	0	175
4/3/01	13	2	175	0	175
4/24/01	14	2	99	0	99
4/24/01	15	2	102	0	102
4/24/01	16	2	102	0	102
4/24/01	17	2	79	0	79
4/24/01	18	2	92	0	92
4/24/01	19	2	86	0	86
4/24/01	20	2	89	0	89
4/24/01	21	2	97	0	97
4/24/01	22	2	82	0	82
4/24/01	23	2	44	0	44
4/24/01	24	2	41	0	41
4/25/01	16	2	108	0	108
4/25/01	17	2	108	0	108
4/25/01	18	2	94	0	94
4/25/01	19	2	87	0	87
4/25/01	20	2	82	0	82
4/25/01	21	2	92	0	92
4/25/01	22	2	82	0	82
5/7/01	9	2	97	0	97
5/7/01	10	2	97	0	97
5/7/01	11	2	97	0	97
5/7/01	12	2	97	0	97
5/7/01	13	2	183	0	183
5/7/01	14	2	183	0	183
5/7/01	15	2	104	0	104
5/7/01	16	2	104	0	104
5/7/01	17	3	104	0	104
5/7/01	18	3	104	0	104
5/7/01	19	2	97	0	97
5/7/01	20	2	97	0	97
5/7/01	21	2	97	0	97
5/7/01	22	2	97	0	97
5/7/01	23	2	29	0	29
5/7/01	24	2	29	0	29
5/8/01	9	2	122	0	122
5/8/01	10	2	25	0	25
5/8/01	11	2	172	0	172
5/8/01	12	2	122	0	122
5/8/01	13	2	25	0	25
5/8/01	14	2	25	0	25
5/8/01	15	2	25	0	25
5/8/01	16	3	25	0	25
5/8/01	17	3	25	0	25
5/8/01	18	3	25	0	25
5/8/01	19	2	25	0	25

date	*hour*	*Stage*	*Net HA Exports*	*Net RT Exports*	*Total Net Exports*
5/8/01	20	2	25	0	25
5/8/01	21	2	25	0	25
5/8/01	22	2	25	0	25
5/8/01	23	2	25	0	25
5/8/01	24	2	25	0	25
5/9/01	11	2	105	0	105
5/9/01	12	2	5	0	5
5/9/01	13	2	55	0	55
5/9/01	14	2	55	0	55
5/9/01	15	2	55	0	55
5/9/01	20	2	5	0	5
5/9/01	21	2	5	0	5
5/9/01	22	2	105	0	105
5/9/01	23	2	93	0	93
5/9/01	24	2	18	0	18
5/10/01	22	2	100	0	100
5/10/01	23	2	48	0	48
5/10/01	24	2	43	0	43
5/30/01	12	2	53	0	53
5/30/01	13	2	15	0	15
5/30/01	15	2	80	0	80
5/30/01	20	2	49	0	49
5/30/01	23	2	16	0	16
5/30/01	24	2	16	0	16
5/31/01	10	2	75	0	75
5/31/01	11	2	97	0	97
5/31/01	12	2	127	0	127
5/31/01	13	2	50	0	50
5/31/01	14	2	91	0	91
5/31/01	15	2	131	0	131
5/31/01	16	2	15	0	15
5/31/01	17	2	46	0	46
5/31/01	18	2	71	0	71
5/31/01	19	2	71	0	71
5/31/01	20	2	145	0	145
5/31/01	21	2	97	0	97
5/31/01	22	2	139	0	139
5/31/01	23	2	68	0	68
Totals			**242,175**	**-8,967**	**233,208**

Sources and Notes:

Source is California ISO response to Data Request CAL-ISO-4.

Hours listed are those during CAISO declared emergencies in which Powerex was a net exporter from the ISO to the Northwest.

Net exports to the Northwest are net exports scheduled on the CAPJAK_5_OLINDA, CASCAD_1_CRAGVW, MALIN_5_RNDMTN and SYLMAR_2_NOB tie points.

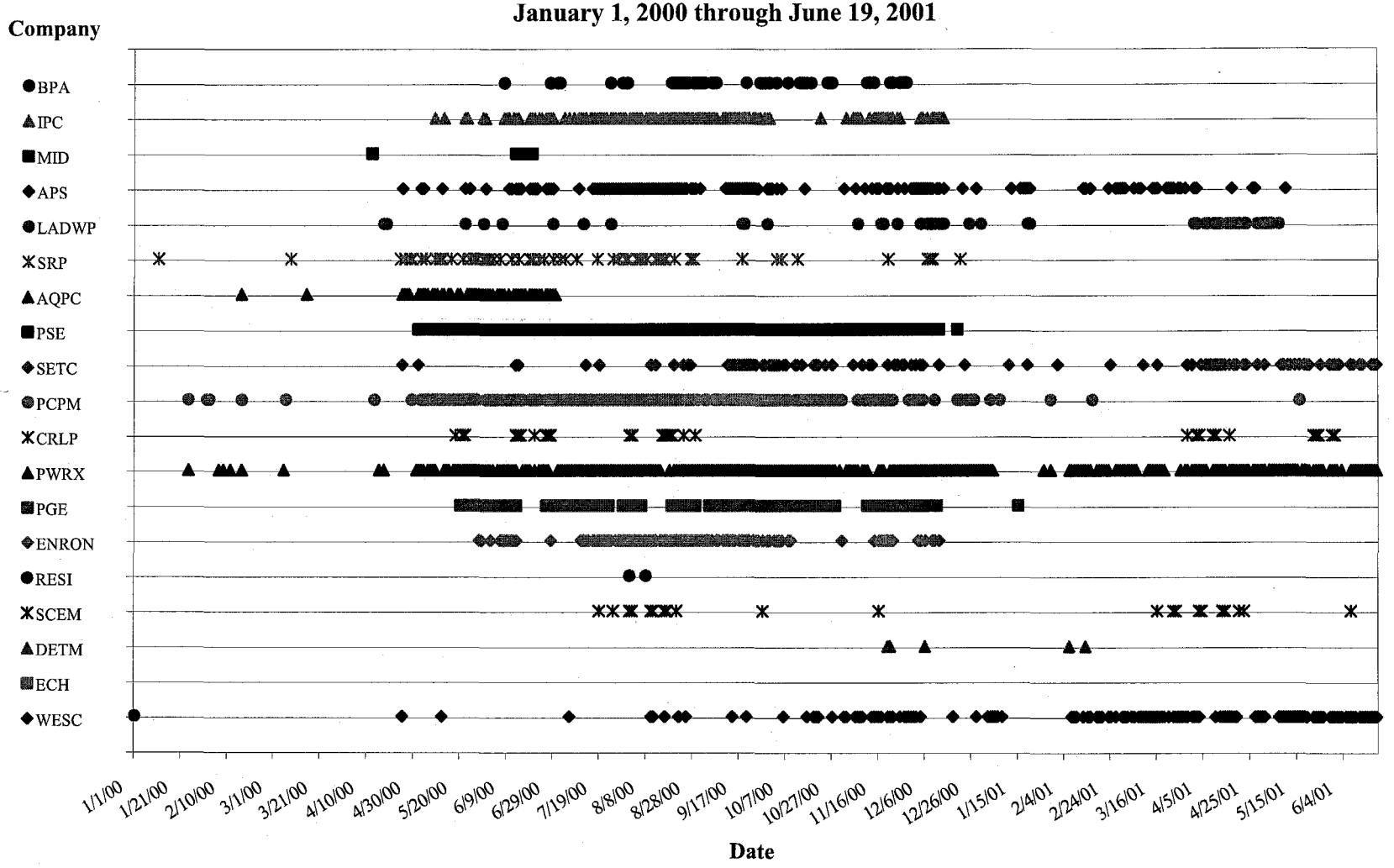
Table D-4

Multiple Party Ricochet Trades between Sempra, Dynegy and Pacificorp in March, 2001 As Reflected in Sempra's Trading Book

TRADE DATE	BUY/ SELL	SEMPRA's COUNTERPARTY	SERVICE	LOCATION	PRICE	QUANTITY	UNIT	DELIVERY DATES
3/8/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$300.00	-1814	MW	03/08/2001 - 03/08/2001
3/8/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$320.00	1814	MW	03/08/2001 - 03/08/2001
3/9/01	S	PACIFICORP	FIRM ENERGY	COB SN	$300.00	-1814	MW	03/08/2001 - 03/08/2001
3/9/01	B	PACIFICORP	FIRM ENERGY	COB NS	$320.00	1814	MW	03/08/2001 - 03/08/2001
3/9/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$376.81	-7486	MW	03/08/2001 - 03/08/2001
3/6/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$250.00	-910	MW	03/05/2001 - 03/05/2001
3/6/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$270.00	910	MW	03/05/2001 - 03/05/2001
3/6/01	S	PACIFICORP	FIRM ENERGY	COB SN	$300.00	-910	MW	03/05/2001 - 03/05/2001
3/6/01	B	PACIFICORP	FIRM ENERGY	COB NS	$320.00	910	MW	03/05/2001 - 03/05/2001
3/6/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$471.97	-11454	MW	03/05/2001 - 03/05/2001
3/8/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$300.00	-1634	MW	03/07/2001 - 03/07/2001
3/8/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$320.00	1634	MW	03/07/2001 - 03/07/2001
3/8/01	S	PACIFICORP	FIRM ENERGY	COB SN	$300.00	-1634	MW	03/07/2001 - 03/07/2001
3/8/01	B	PACIFICORP	FIRM ENERGY	COB NS	$320.00	1634	MW	03/07/2001 - 03/07/2001
3/8/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$410.70	-10577	MW	03/07/2001 - 03/07/2001
3/12/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$300.00	-1700	MW	03/09/2001 - 03/09/2001
3/12/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$320.00	1700	MW	03/09/2001 - 03/09/2001
3/12/01	S	PACIFICORP	FIRM ENERGY	COB SN	$300.00	-1700	MW	03/09/2001 - 03/09/2001
3/12/01	B	PACIFICORP	FIRM ENERGY	COB NS	$320.00	1700	MW	03/09/2001 - 03/09/2001
3/12/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$357.85	-5526	MW	03/09/2001 - 03/09/2001
3/13/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$200.00	-140	MW	03/12/2001 - 03/12/2001
3/13/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$220.00	140	MW	03/12/2001 - 03/12/2001
3/13/01	S	PACIFICORP	FIRM ENERGY	COB SN	$200.00	-140	MW	03/12/2001 - 03/12/2001
3/13/01	B	PACIFICORP	FIRM ENERGY	COB NS	$220.00	140	MW	03/12/2001 - 03/12/2001
3/13/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$262.51	-1795	MW	03/12/2001 - 03/12/2001
3/20/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$100.00	-150	MW	03/19/2001 - 03/19/2001
3/20/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$120.00	150	MW	03/19/2001 - 03/19/2001
3/20/01	S	PACIFICORP	FIRM ENERGY	COB SN	$100.00	-150	MW	03/19/2001 - 03/19/2001
3/20/01	B	PACIFICORP	FIRM ENERGY	COB NS	$120.00	150	MW	03/19/2001 - 03/19/2001
3/20/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$510.98	-3579	MW	03/19/2001 - 03/19/2001
3/21/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$125.00	-200	MW	03/20/2001 - 03/20/2001
3/21/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$140.63	189	MW	03/20/2001 - 03/20/2001
3/21/01	S	PACIFICORP	FIRM ENERGY	COB SN	$100.00	-189	MW	03/20/2001 - 03/20/2001
3/21/01	B	PACIFICORP	FIRM ENERGY	COB NS	$120.00	189	MW	03/20/2001 - 03/20/2001
3/21/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$547.60	-920	MW	03/20/2001 - 03/20/2001
3/22/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$200.00	-4088	MW	03/21/2001 - 03/21/2001
3/22/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$220.00	4088	MW	03/21/2001 - 03/21/2001
3/22/01	S	PACIFICORP	FIRM ENERGY	COB SN	$100.00	-4088	MW	03/21/2001 - 03/21/2001
3/22/01	B	PACIFICORP	FIRM ENERGY	COB NS	$120.00	4088	MW	03/21/2001 - 03/21/2001
3/22/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$558.39	-6809	MW	03/21/2001 - 03/21/2001
3/26/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$200.00	-2096	MW	03/23/2001 - 03/23/2001
3/26/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$220.00	2096	MW	03/23/2001 - 03/23/2001
3/26/01	S	PACIFICORP	FIRM ENERGY	COB SN	$100.00	-1896	MW	03/23/2001 - 03/23/2001
3/26/01	B	PACIFICORP	FIRM ENERGY	COB NS	$120.00	1896	MW	03/23/2001 - 03/23/2001
3/26/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$441.19	-4937	MW	03/23/2001 - 03/23/2001
3/26/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$200.00	-2640	MW	03/24/2001 - 03/24/2001
3/26/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$220.00	2640	MW	03/24/2001 - 03/24/2001
3/26/01	S	PACIFICORP	FIRM ENERGY	COB SN	$97.71	-2550	MW	03/24/2001 - 03/24/2001
3/26/01	B	PACIFICORP	FIRM ENERGY	COB NS	$120.00	2460	MW	03/24/2001 - 03/24/2001
3/26/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$252.42	-4176	MW	03/24/2001 - 03/24/2001
3/30/01	S	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	NP15	$200.00	-221	MW	03/29/2001 - 03/29/2001
3/30/01	B	DYNEGY POWER MARKETING, INC.	FIRM ENERGY	COB SN	$220.00	221	MW	03/29/2001 - 03/29/2001
3/30/01	S	PACIFICORP	FIRM ENERGY	COB SN	$100.00	-238	MW	03/29/2001 - 03/29/2001
3/30/01	B	PACIFICORP	FIRM ENERGY	COB NS	$120.00	238	MW	03/29/2001 - 03/29/2001
3/30/01	S	CALIFORNIA DEPARTMENT OF WATER RESOURCES	FIRM ENERGY	COB NS	$206.75	-1703	MW	03/29/2001 - 03/29/2001

Source: Sempra Energy Trading Response to Data Request CAL-SET-92, electronic file "SET quarterly reports.xls."

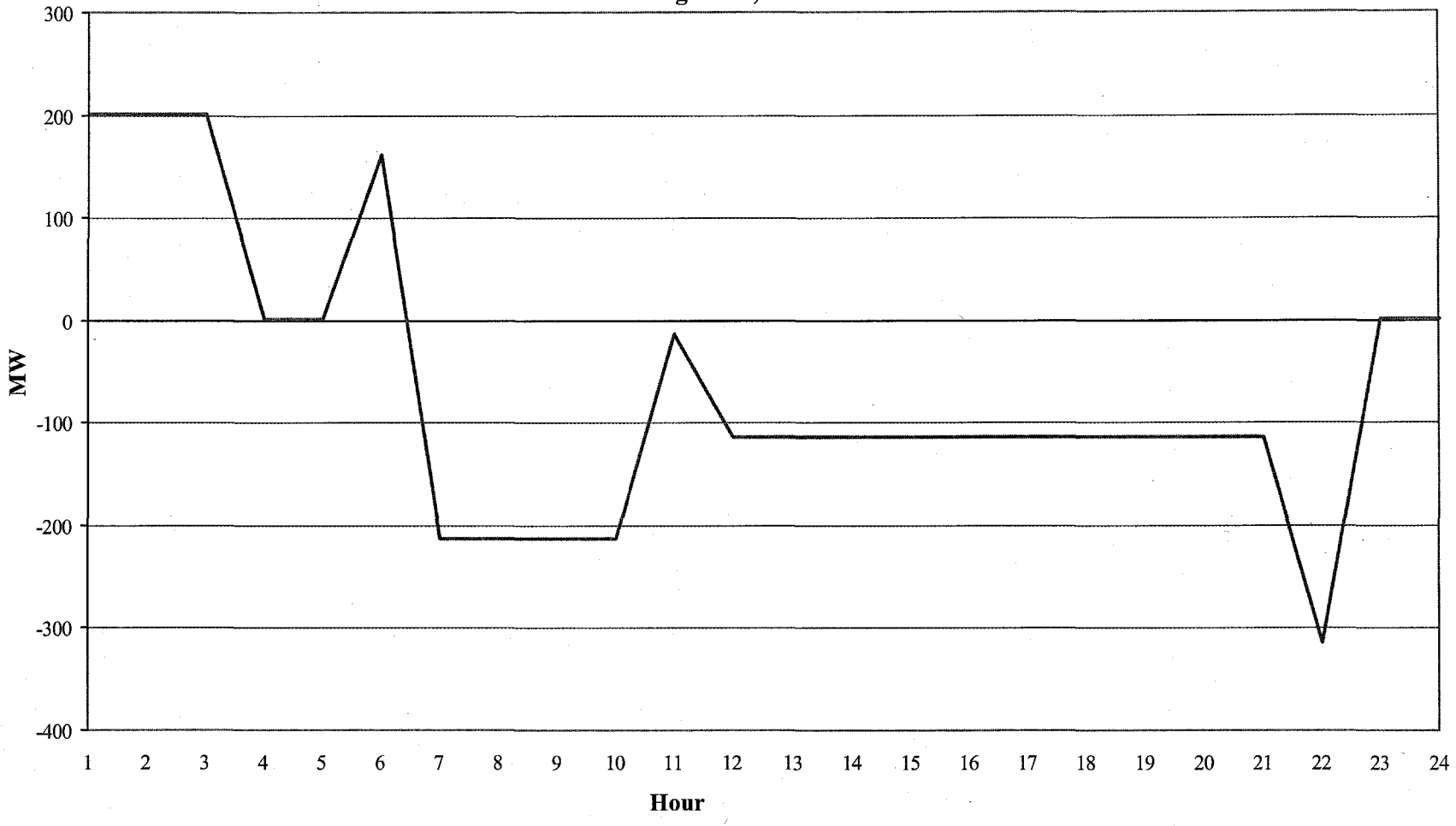
Figure D-7
Potential Single-Party Ricochet Occurrences
January 1, 2000 through June 19, 2001



Source is response to Data Requests CAL-ISO-4 and CAL-ISO-7.

Contains Protected Material
Not Available to Competitive Duty Personnel

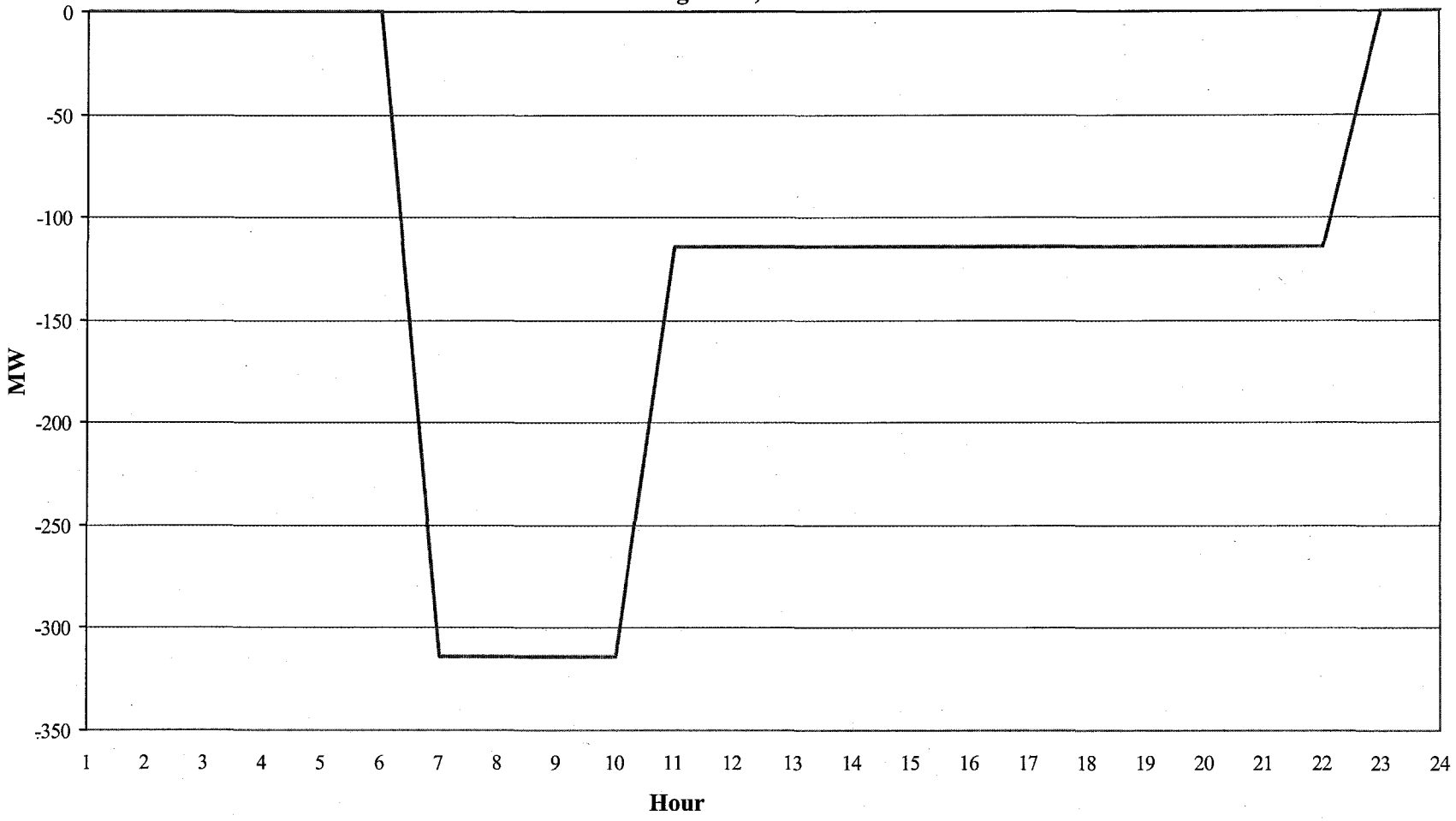
Figure D-8 (page 1 of 53)
Net PX Supply by PowerEX
August 01, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

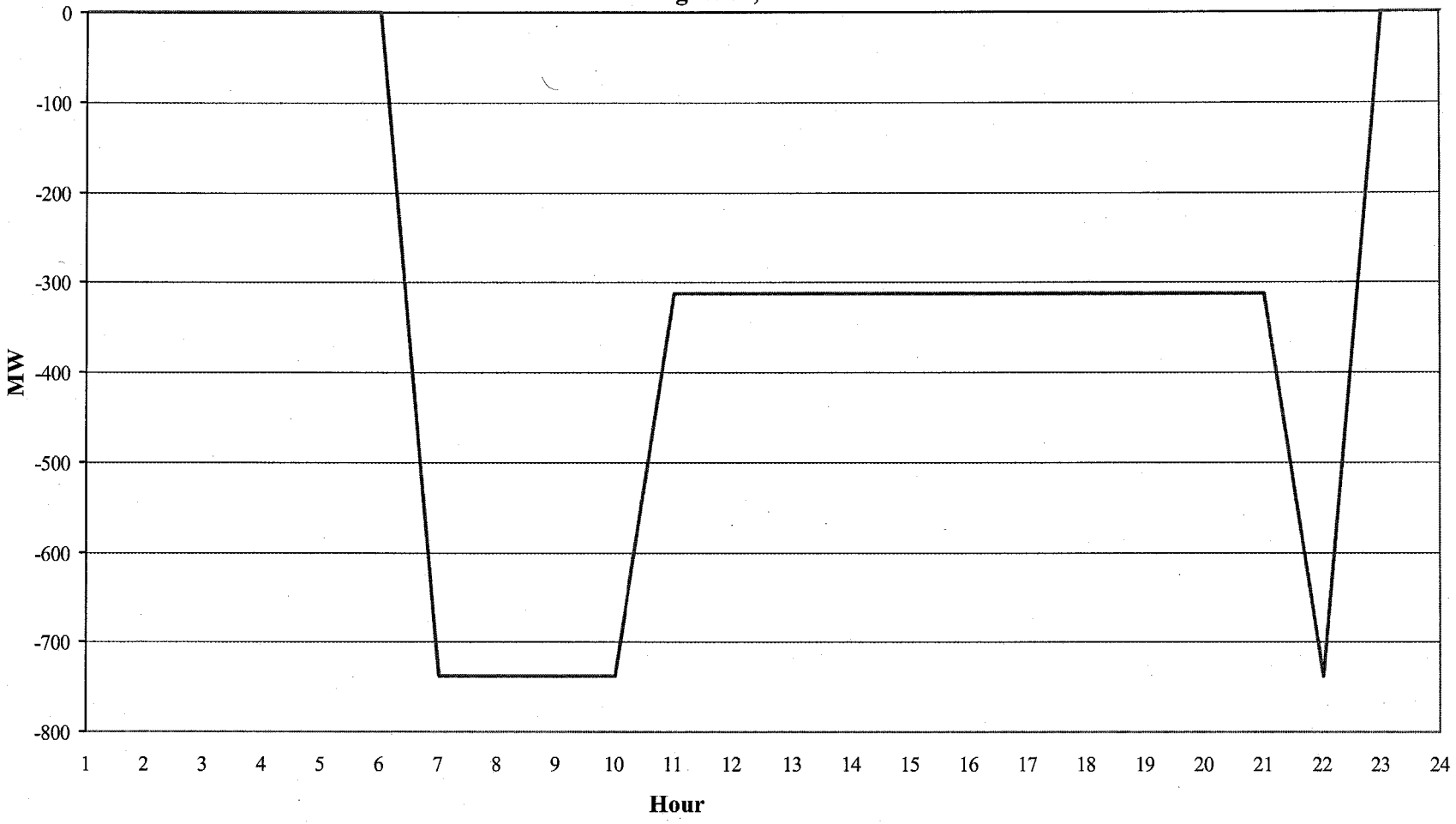
Figure D-8 (page 2 of 53)
Net PX Supply by PowerEX
August 02, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

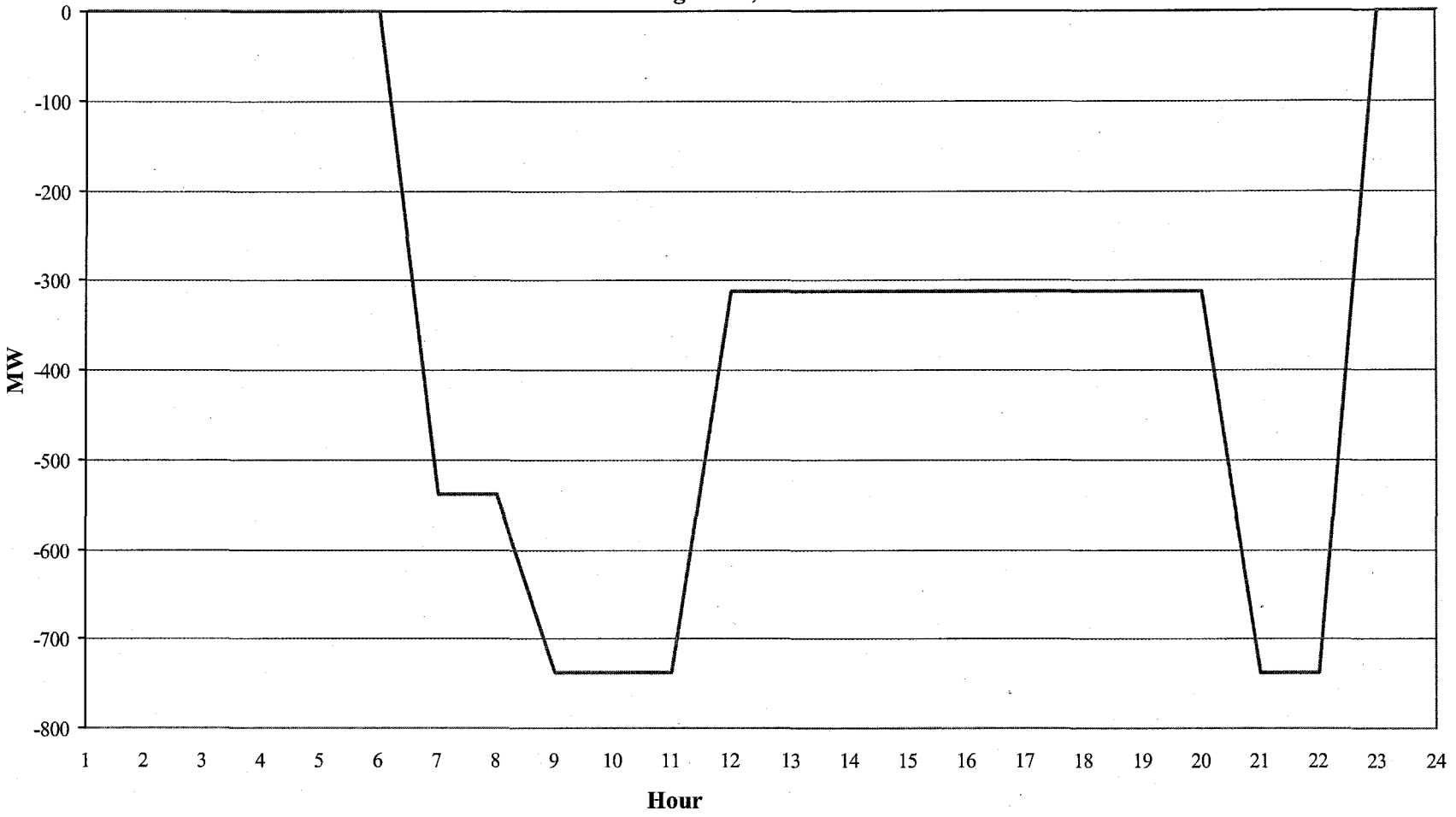
Figure D-8 (page 3 of 53)
Net PX Supply by PowerEX
August 03, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

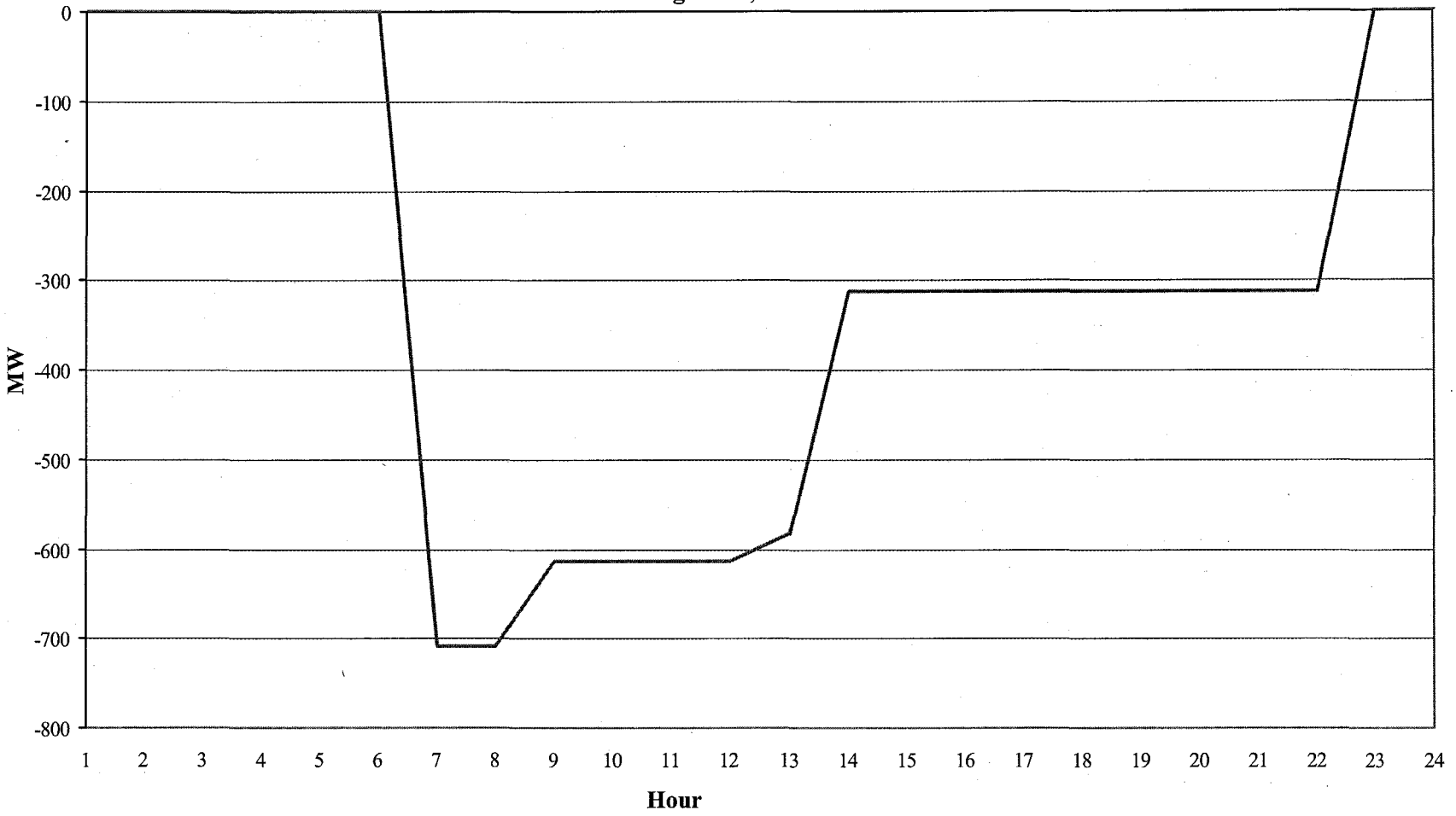
Figure D-8 (page 4 of 53)
Net PX Supply by PowerEX
August 04, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

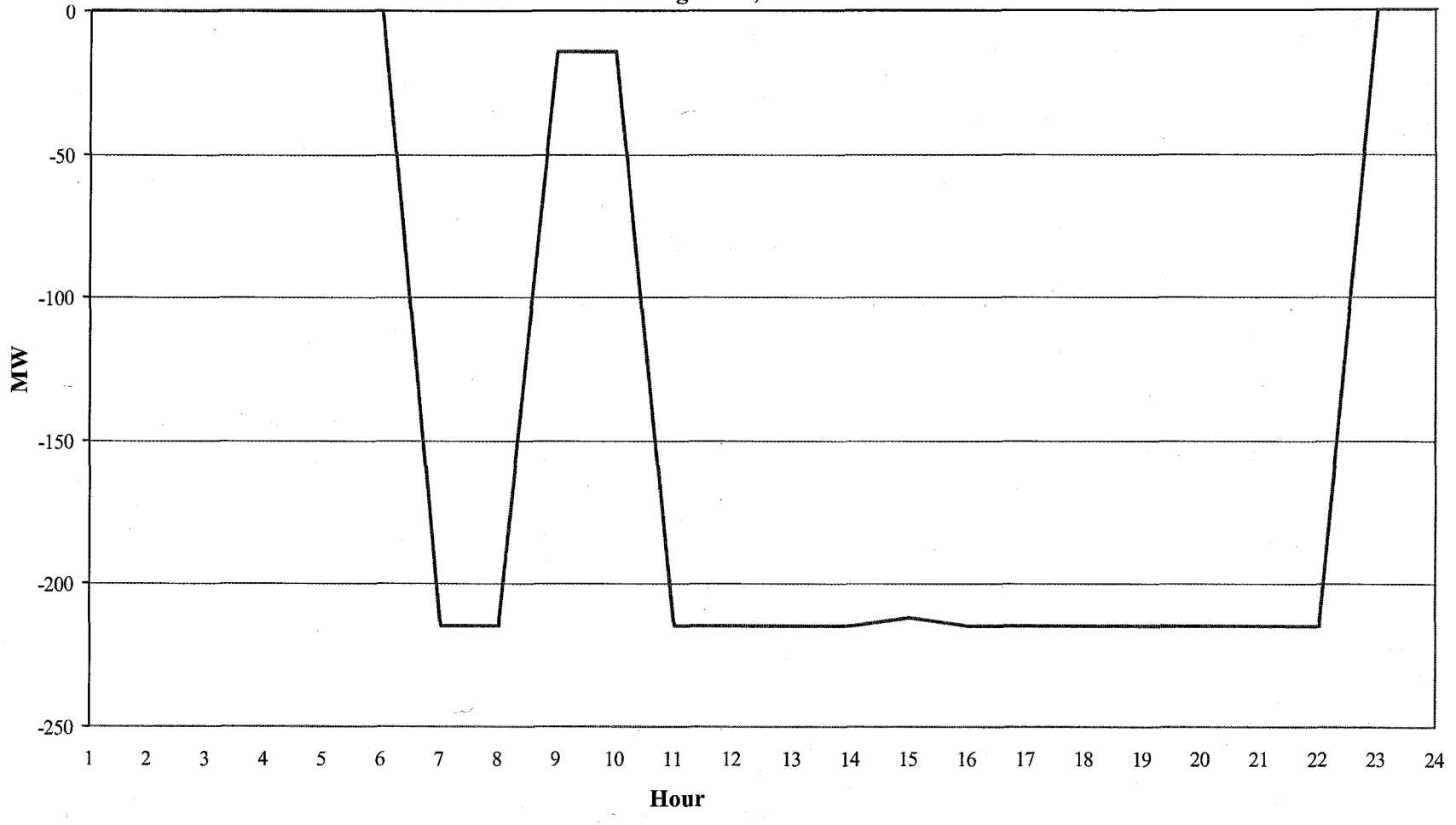
Figure D-8 (page 5 of 53)
Net PX Supply by PowerEX
August 05, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

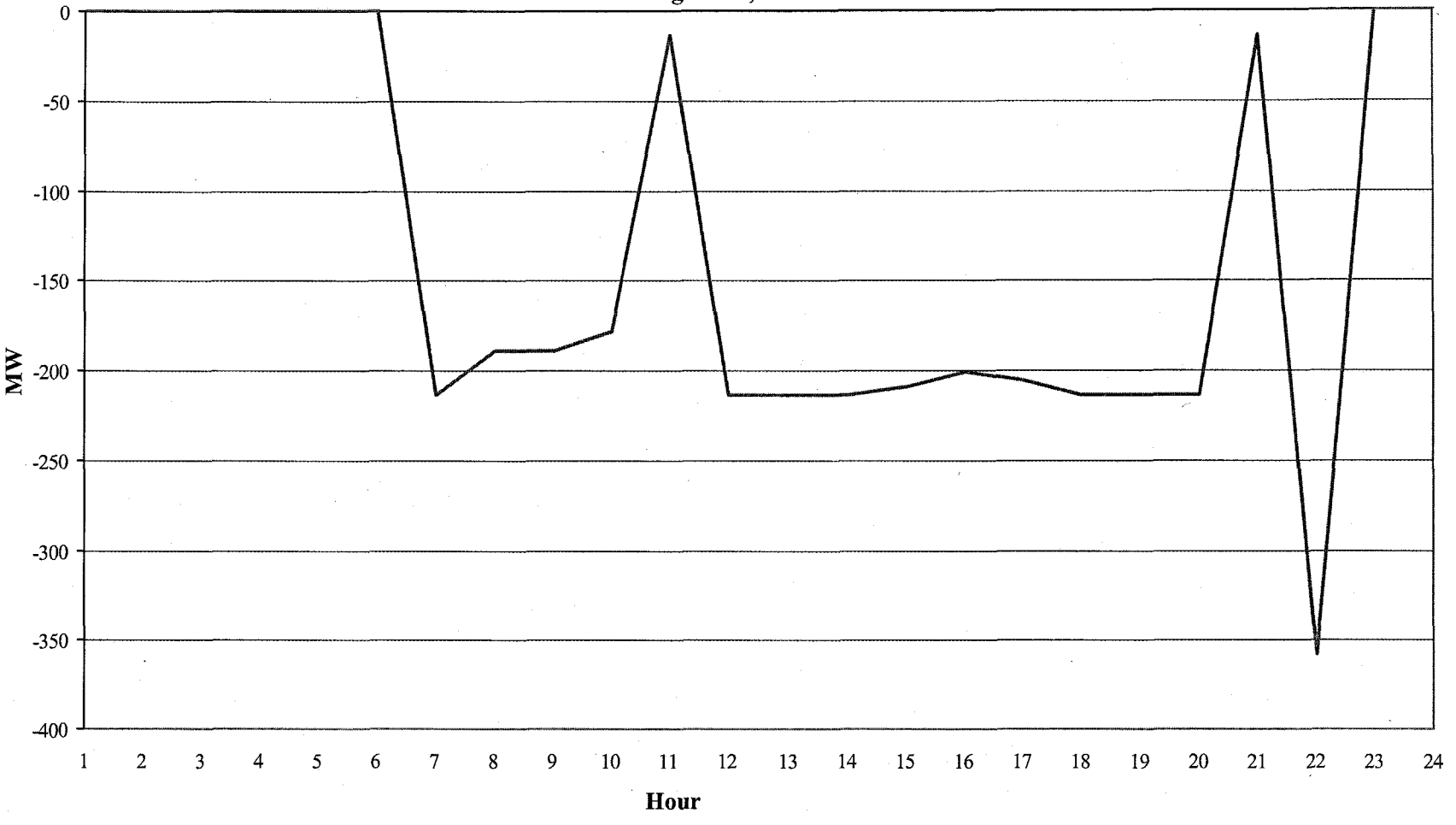
Figure D-8 (page 6 of 53)
Net PX Supply by PowerEX
August 07, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

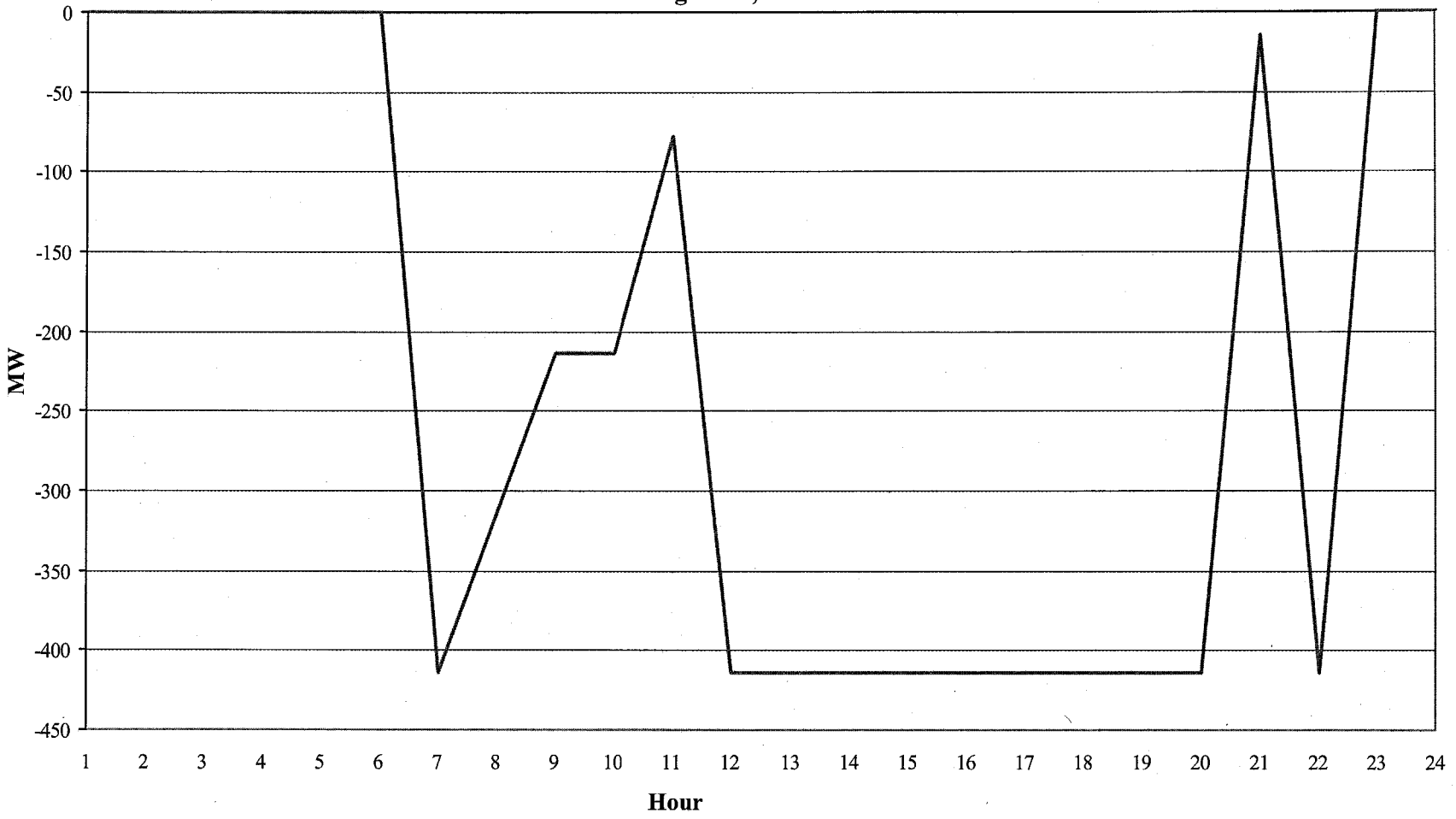
Figure D-8 (page 7 of 53)
Net PX Supply by PowerEX
August 08, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

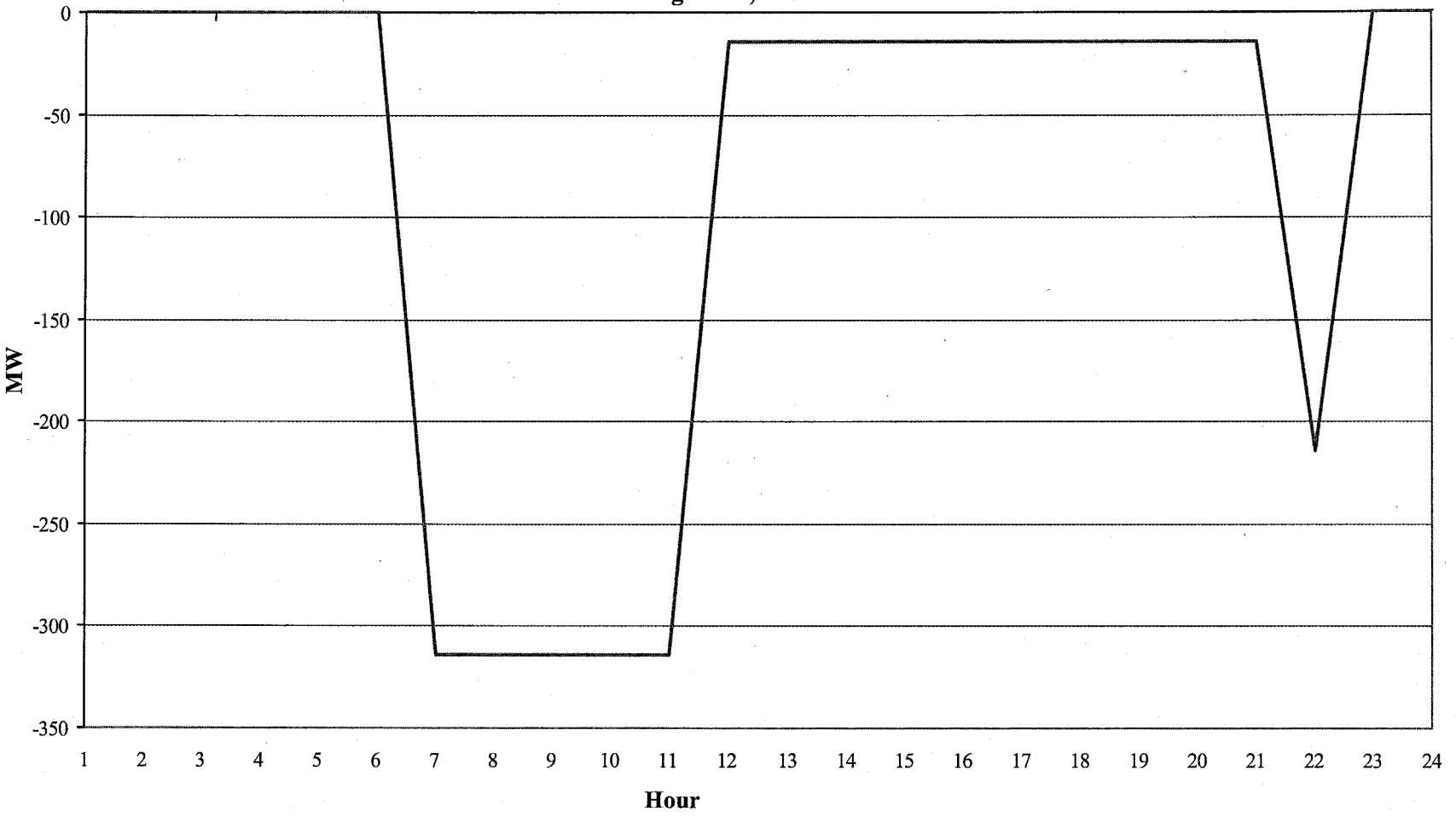
Figure D-8 (page 8 of 53)
Net PX Supply by PowerEX
August 09, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

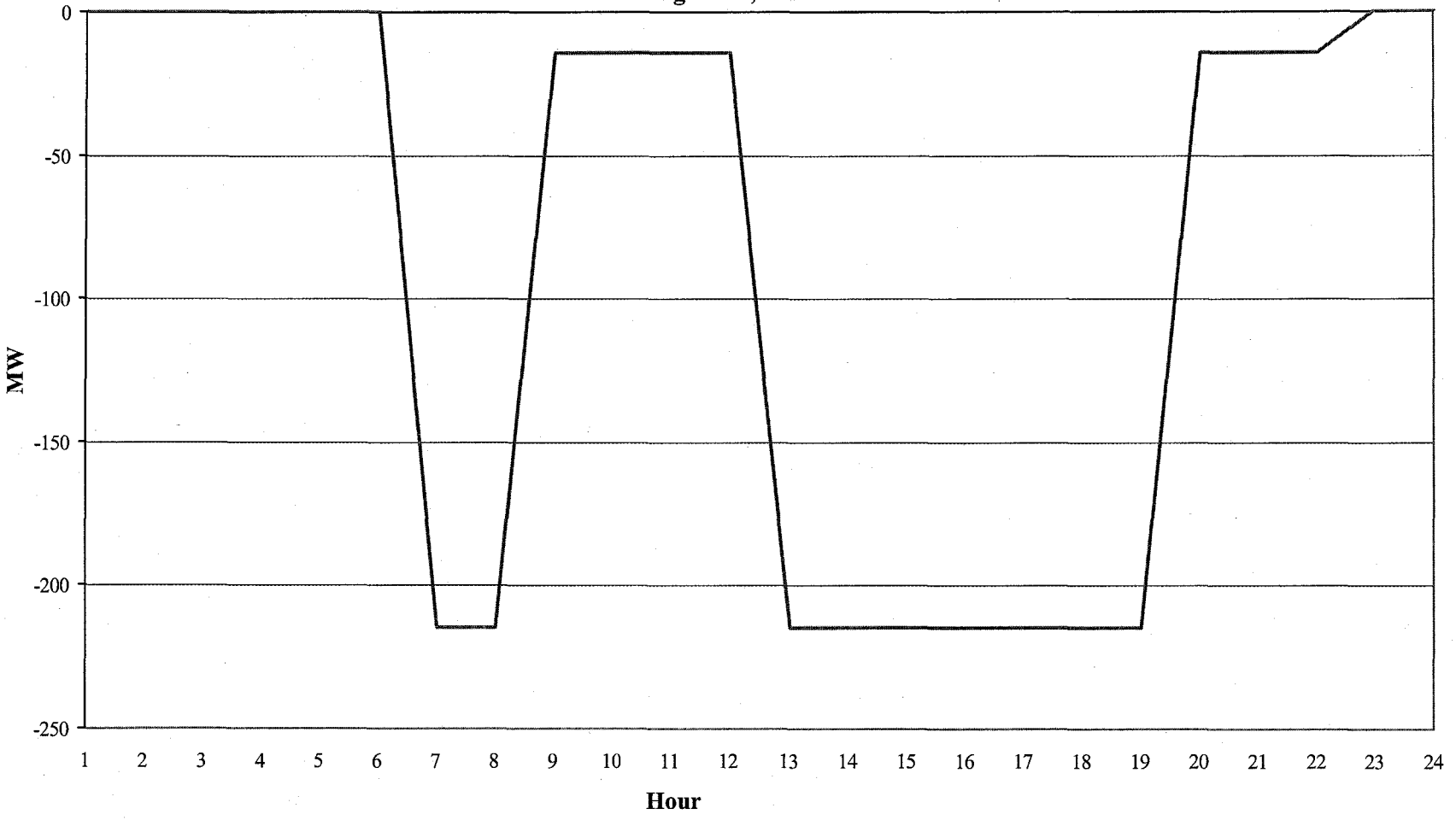
Figure D-8 (page 9 of 53)
Net PX Supply by PowerEX
August 10, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

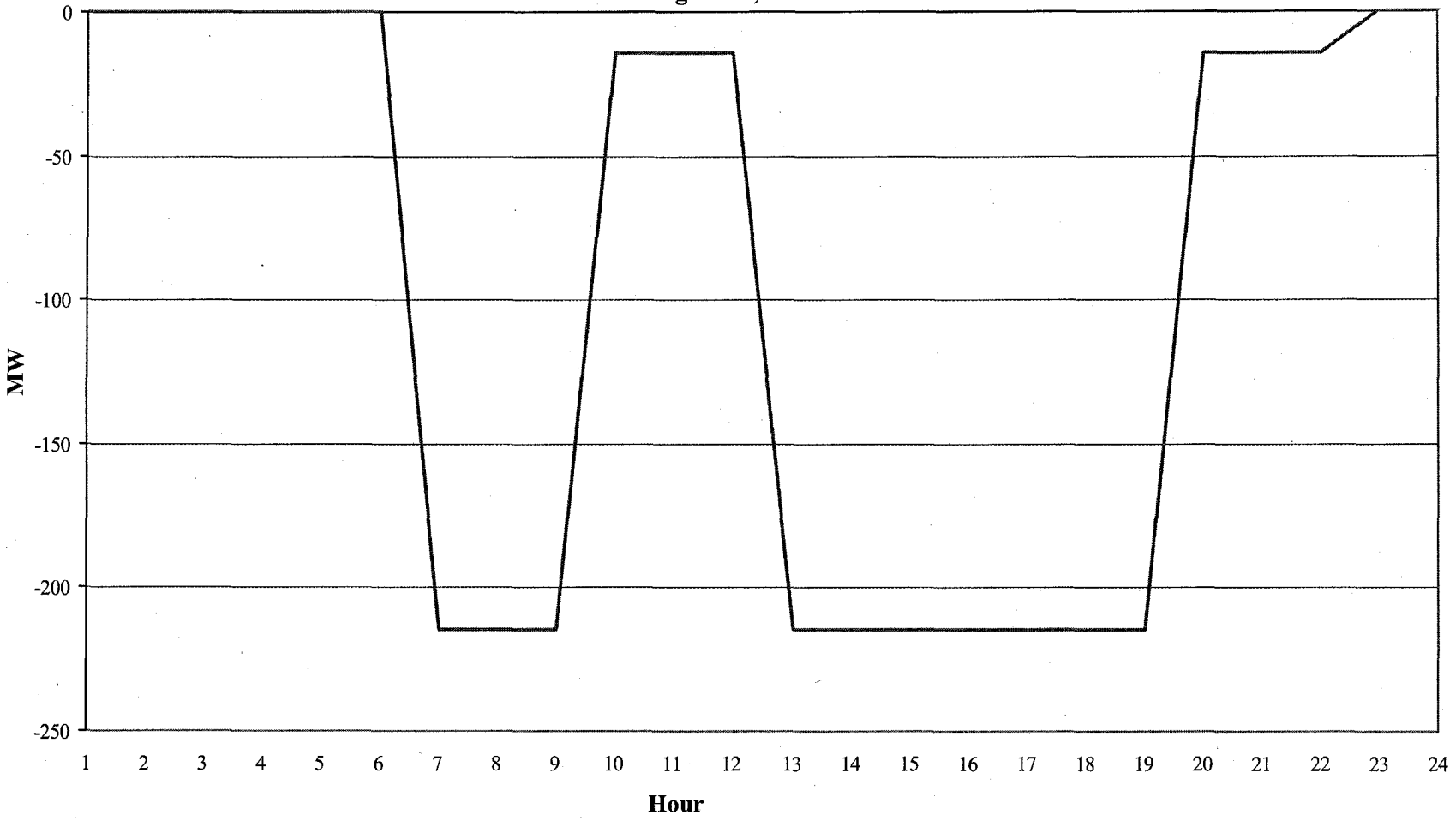
Figure D-8 (page 10 of 53)
Net PX Supply by PowerEX
August 11, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

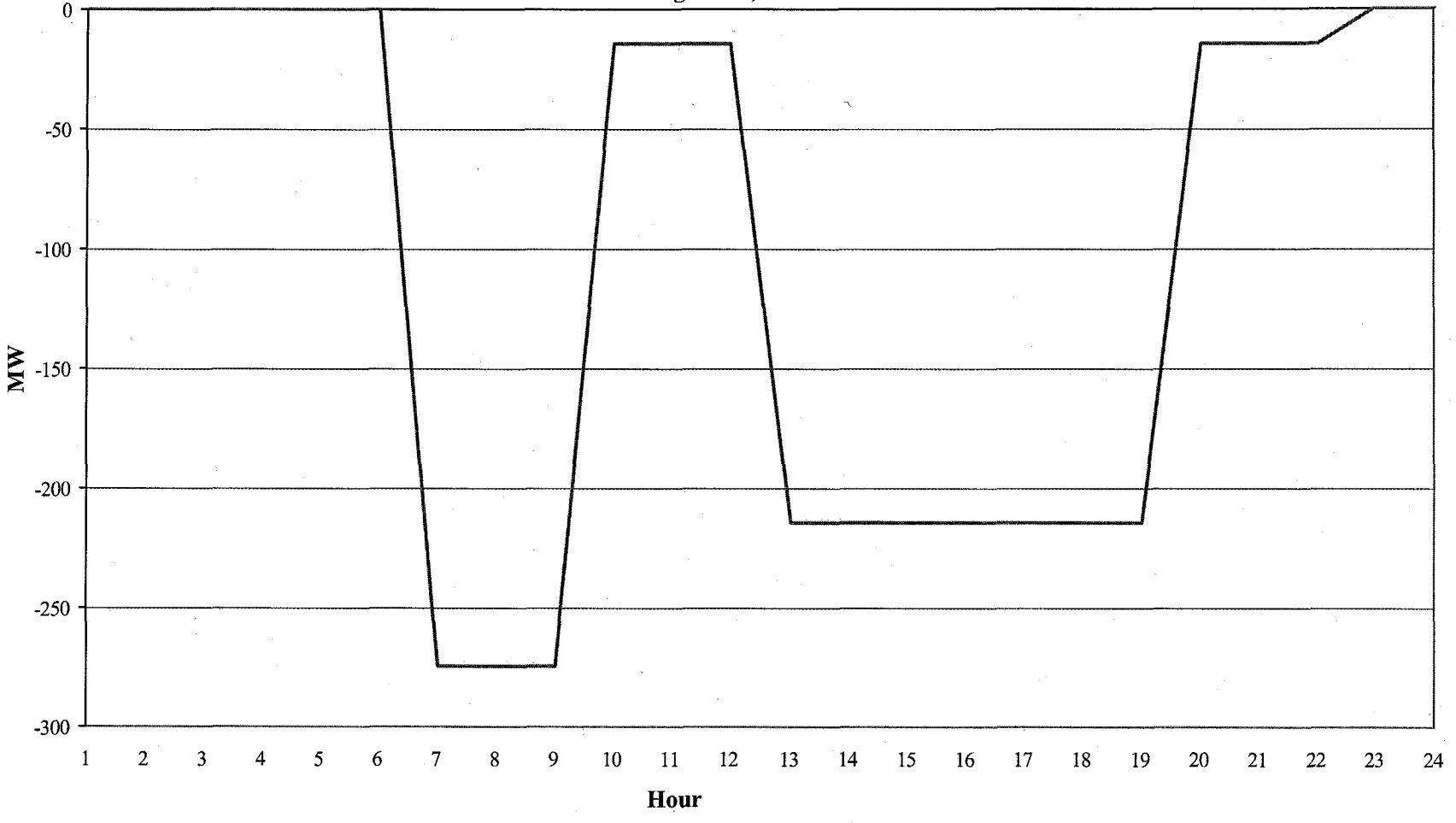
Figure D-8 (page 11 of 53)
Net PX Supply by PowerEX
August 12, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

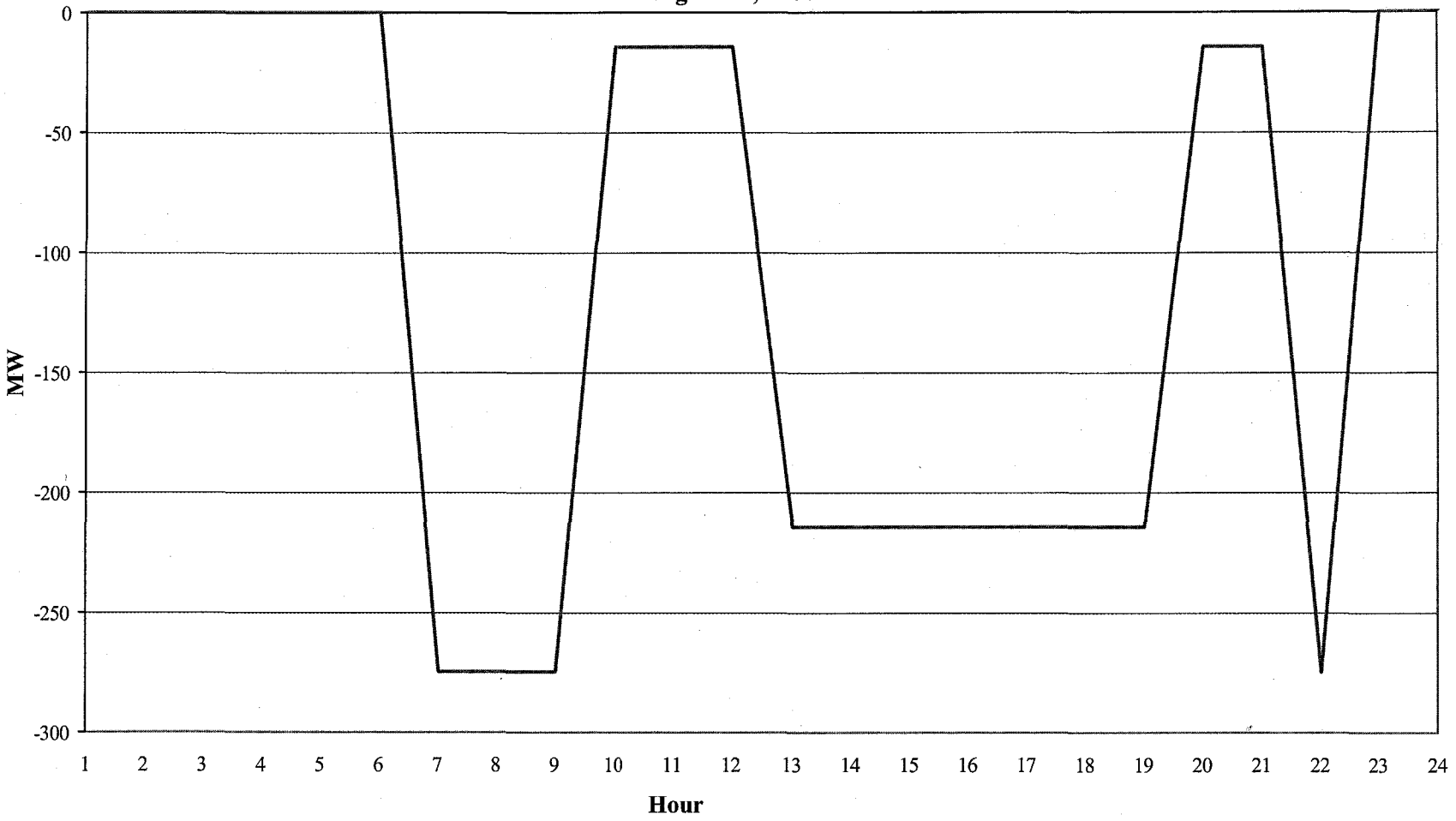
Figure D-8 (page 12 of 53)
Net PX Supply by PowerEX
August 14, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

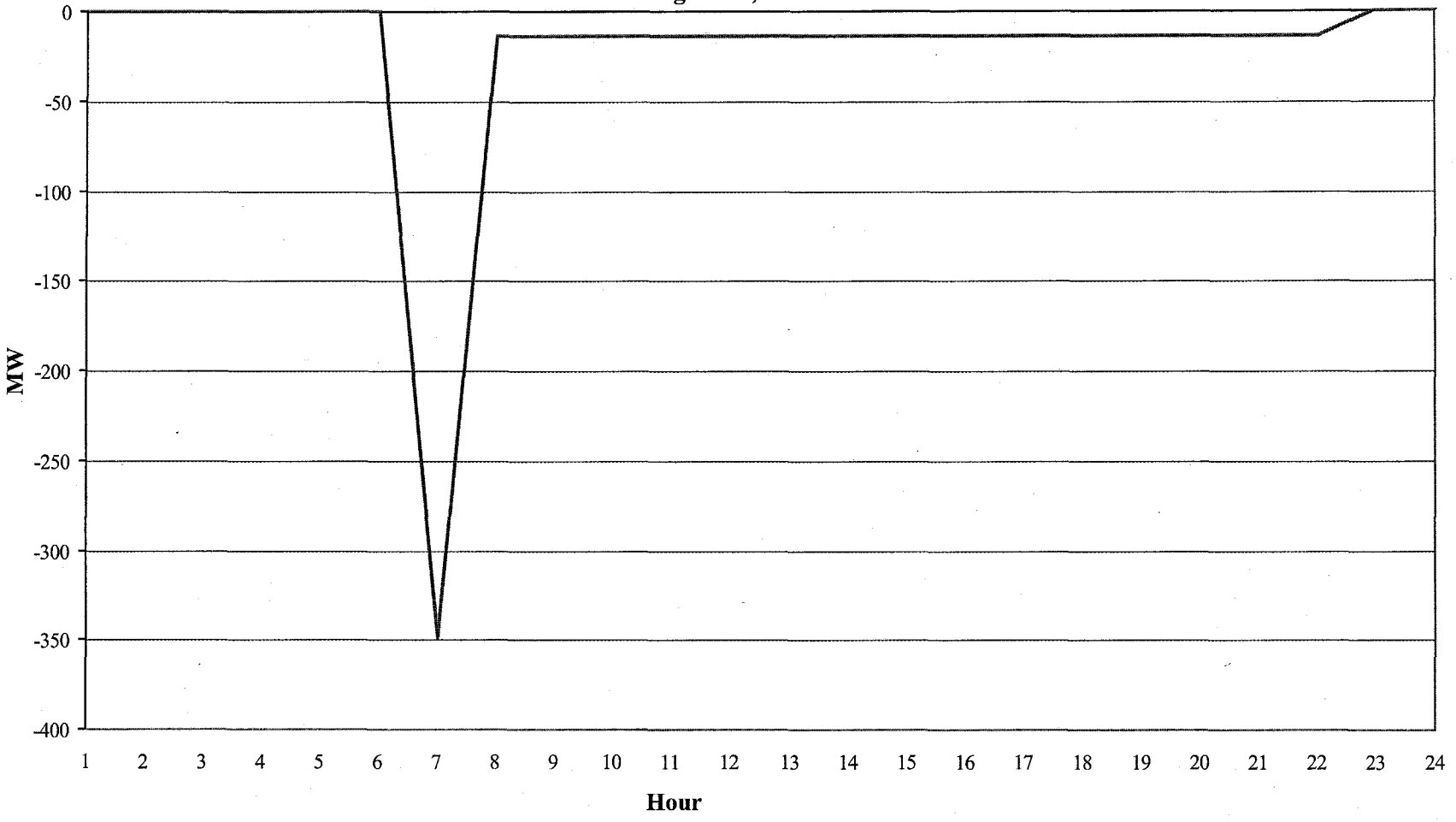
Figure D-8 (page 13 of 53)
Net PX Supply by PowerEX
August 15, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

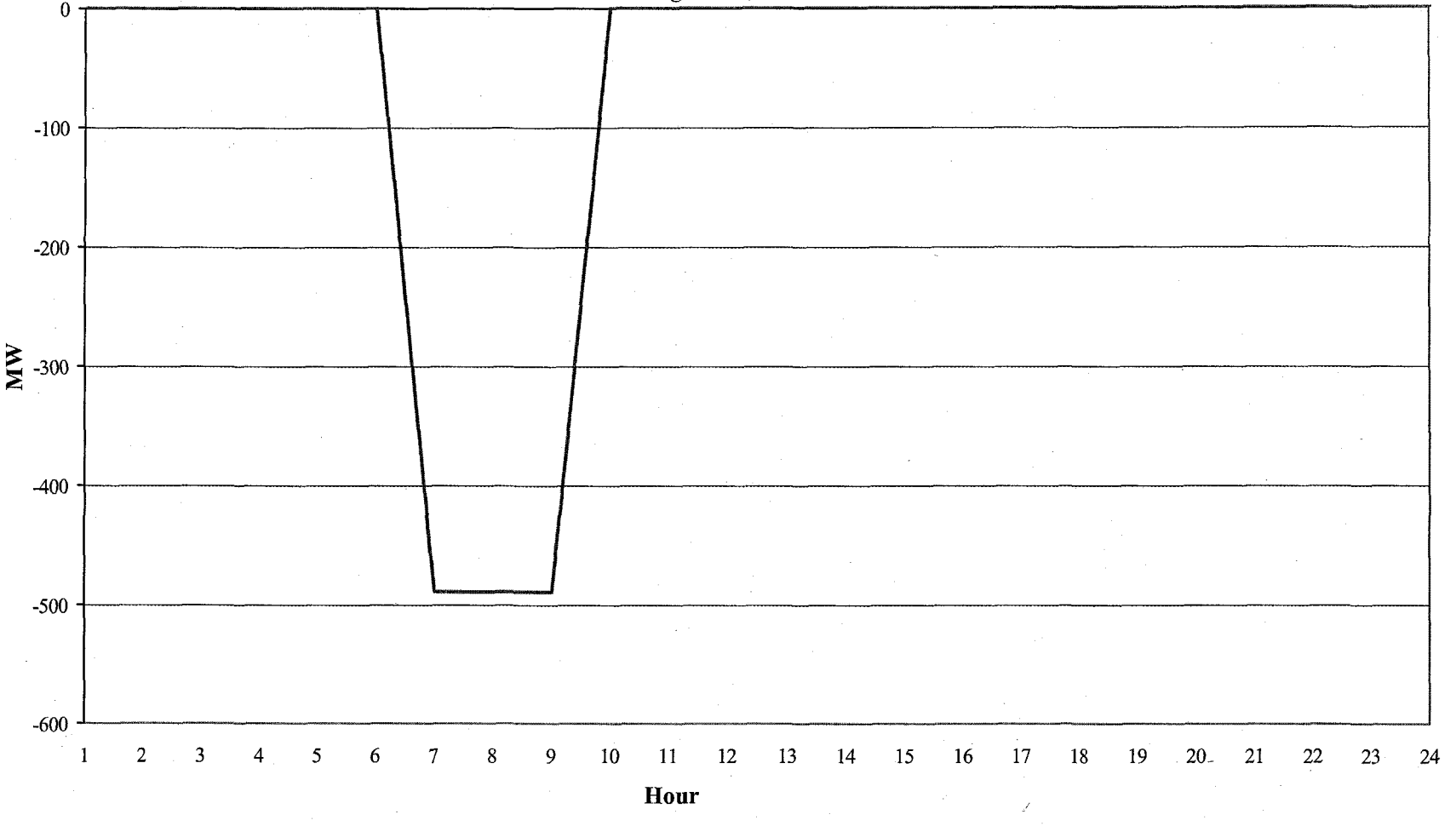
Figure D-8 (page 14 of 53)
Net PX Supply by PowerEX
August 16, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

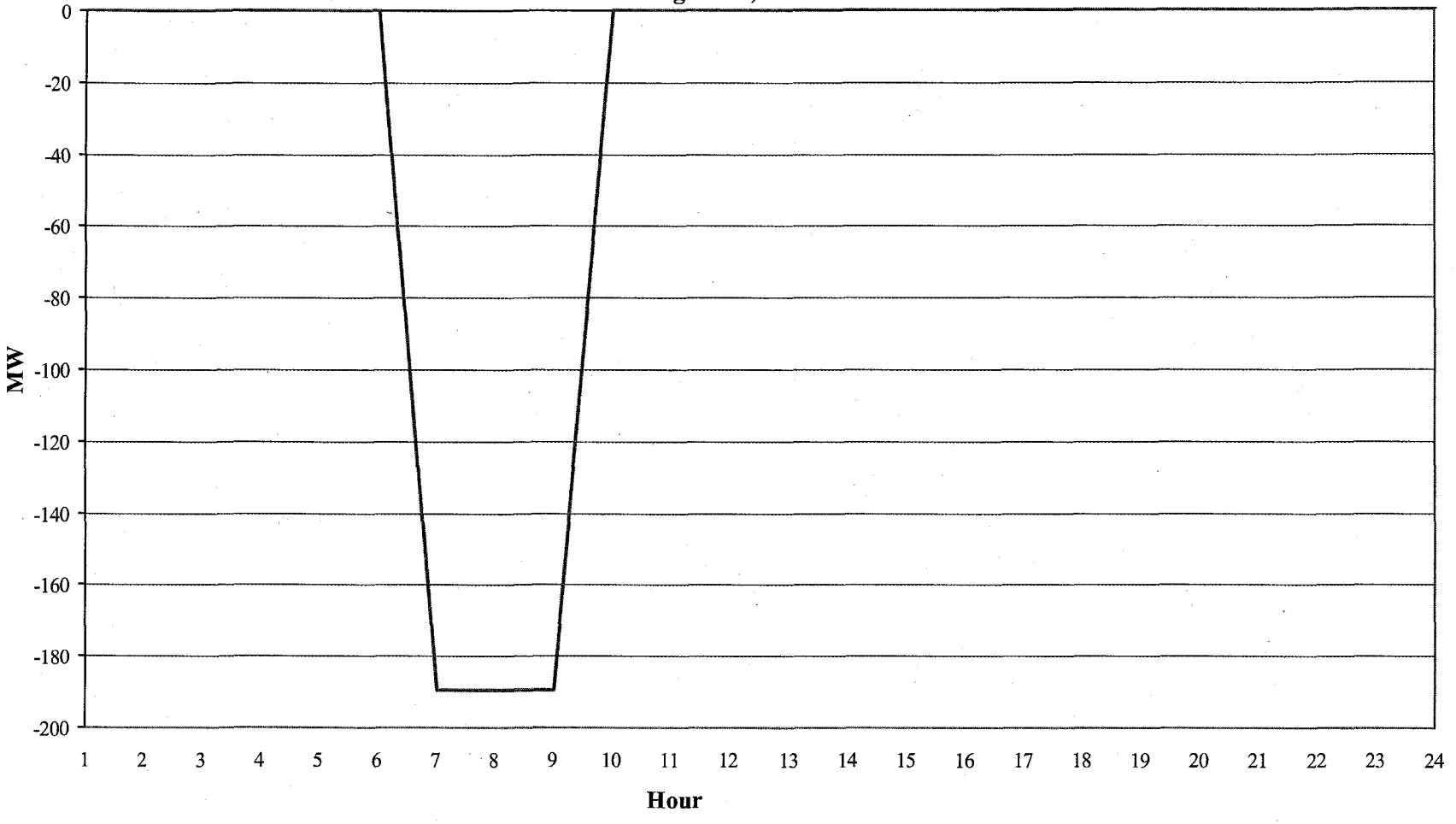
Figure D-8 (page 15 of 53)
Net PX Supply by PowerEX
August 17, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

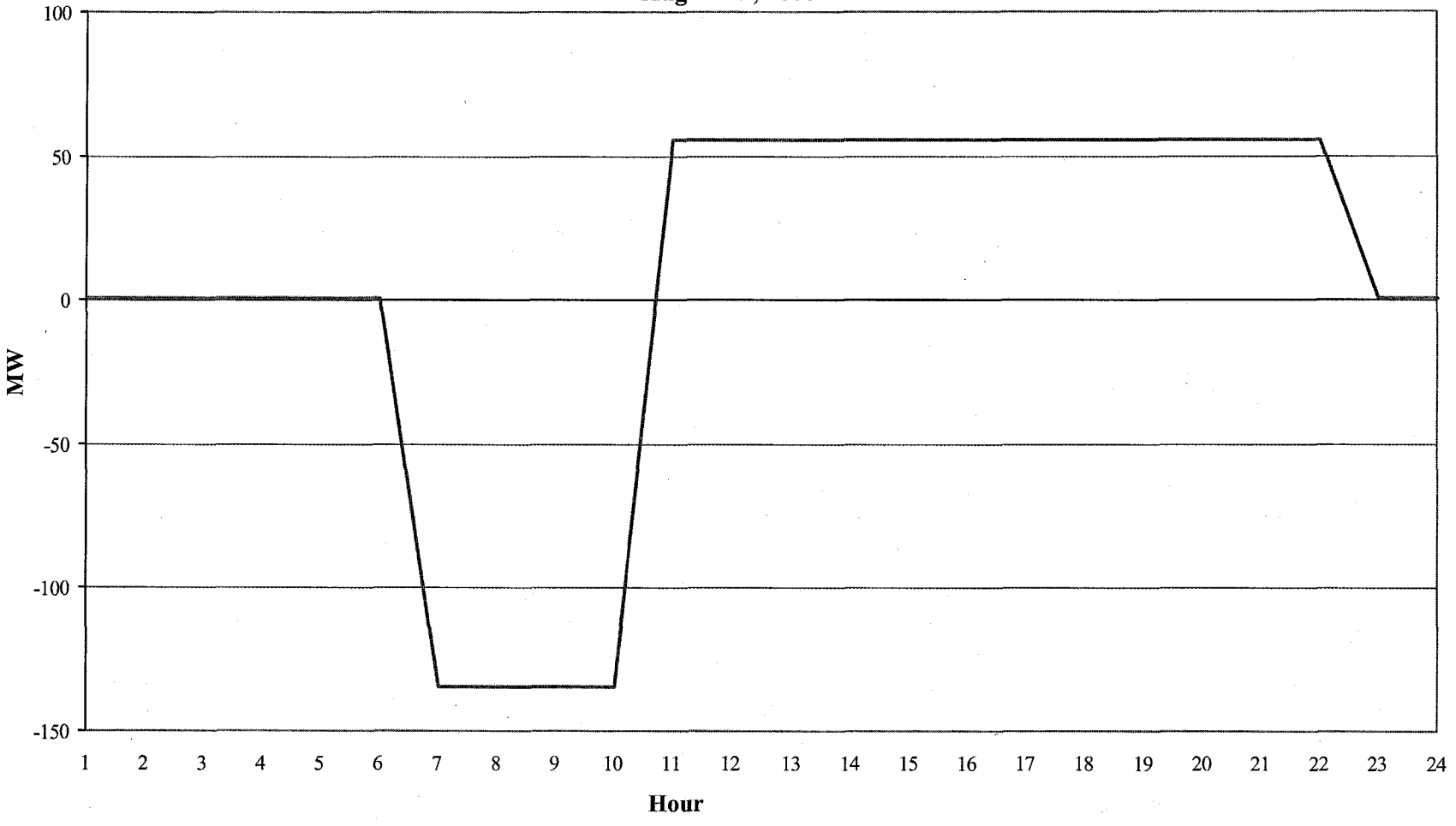
Figure D-8 (page 16 of 53)
Net PX Supply by PowerEX
August 18, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

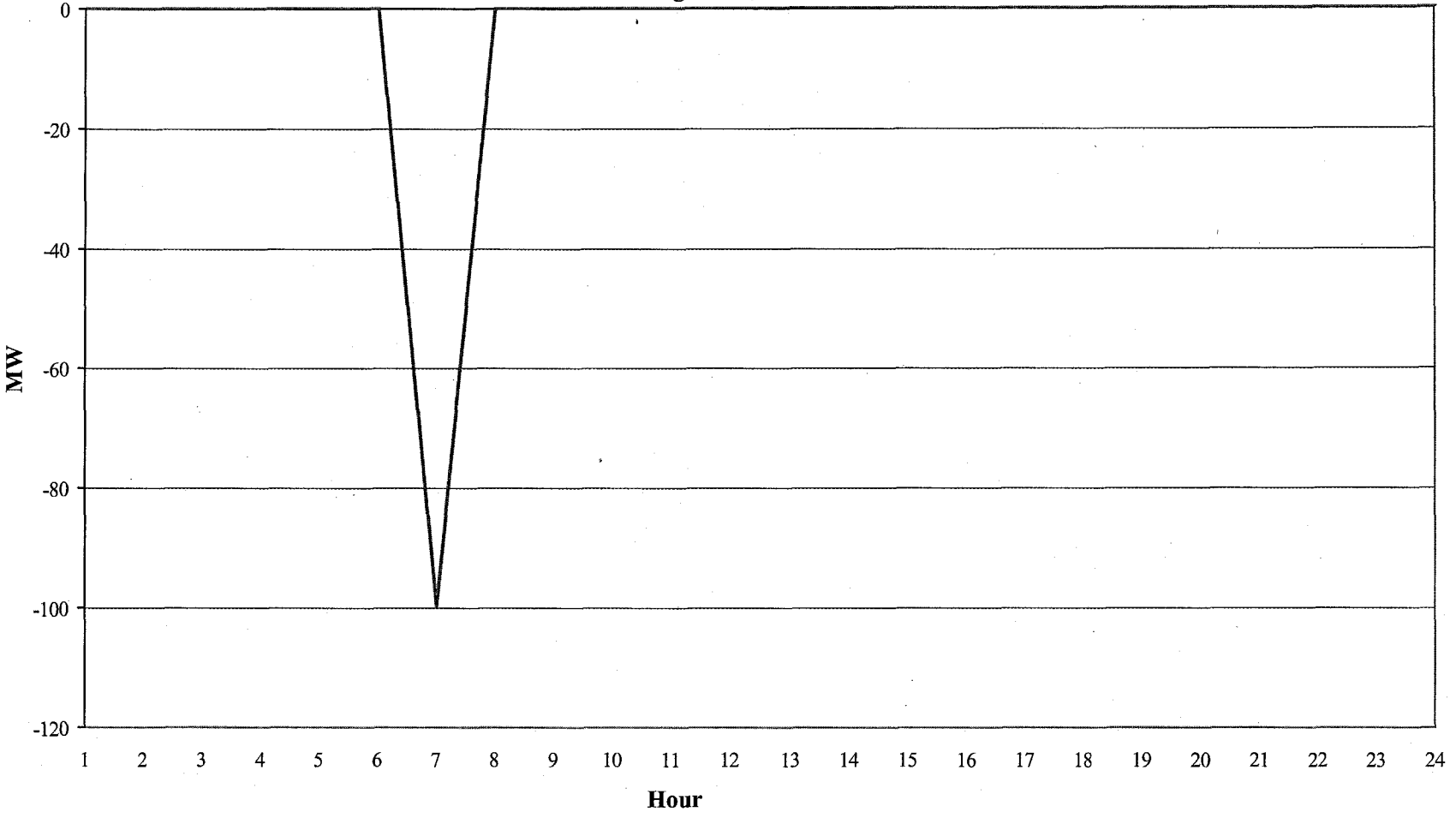
Figure D-8 (page 17 of 53)
Net PX Supply by PowerEX
August 19, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

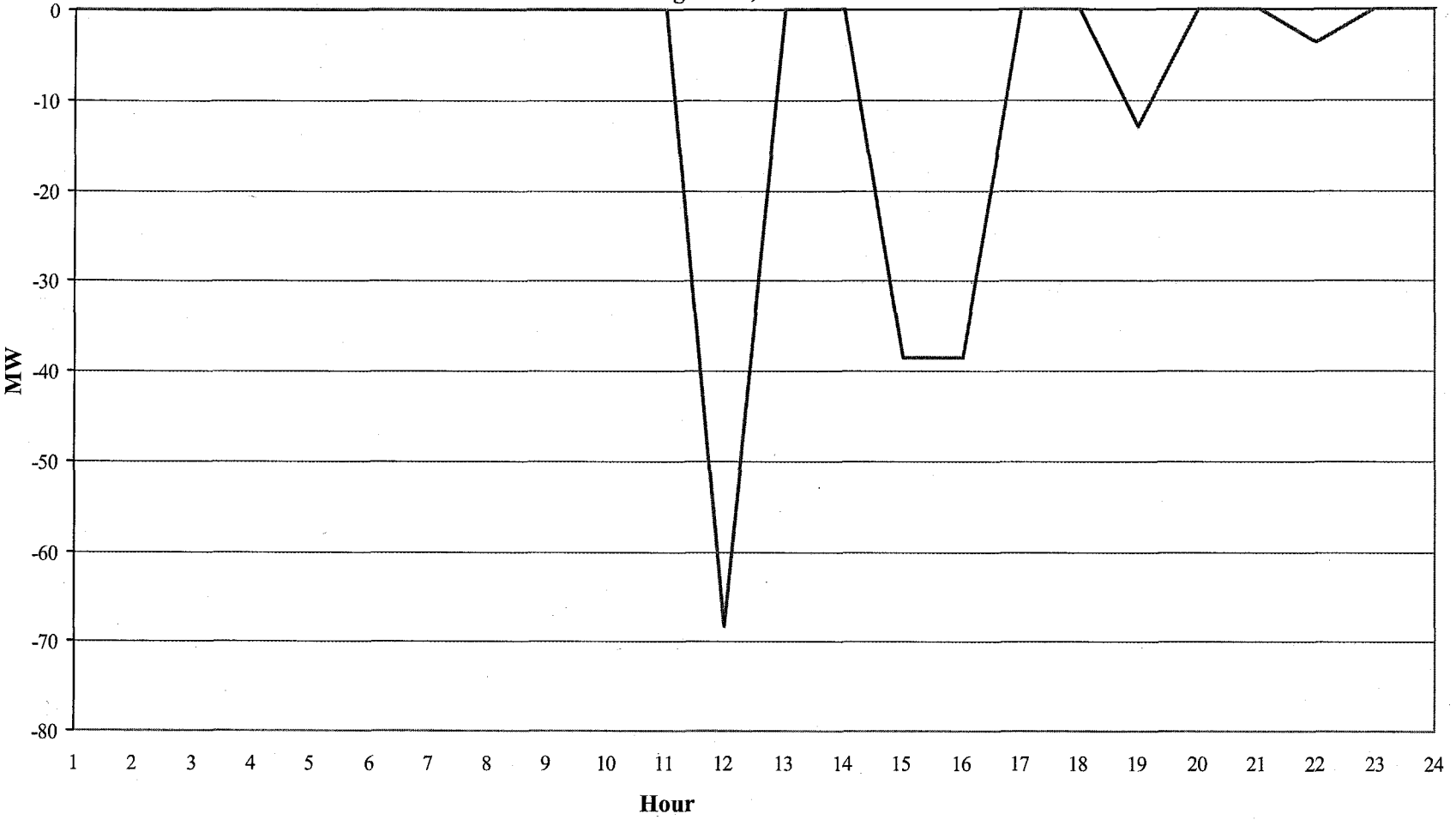
Figure D-8 (page 18 of 53)
Net PX Supply by PowerEX
August 21, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

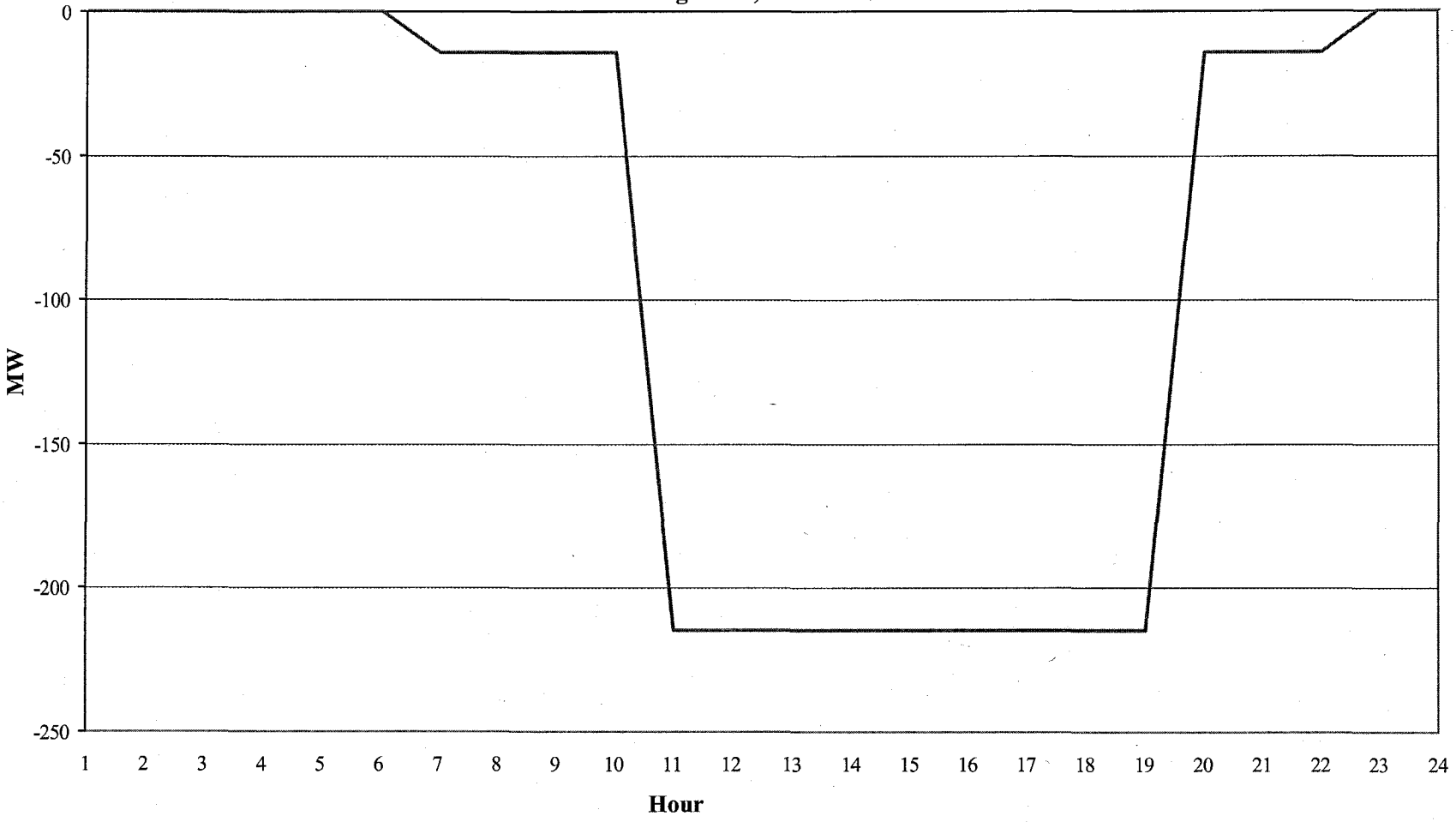
Figure D-8 (page 19 of 53)
Net PX Supply by PowerEX
August 22, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

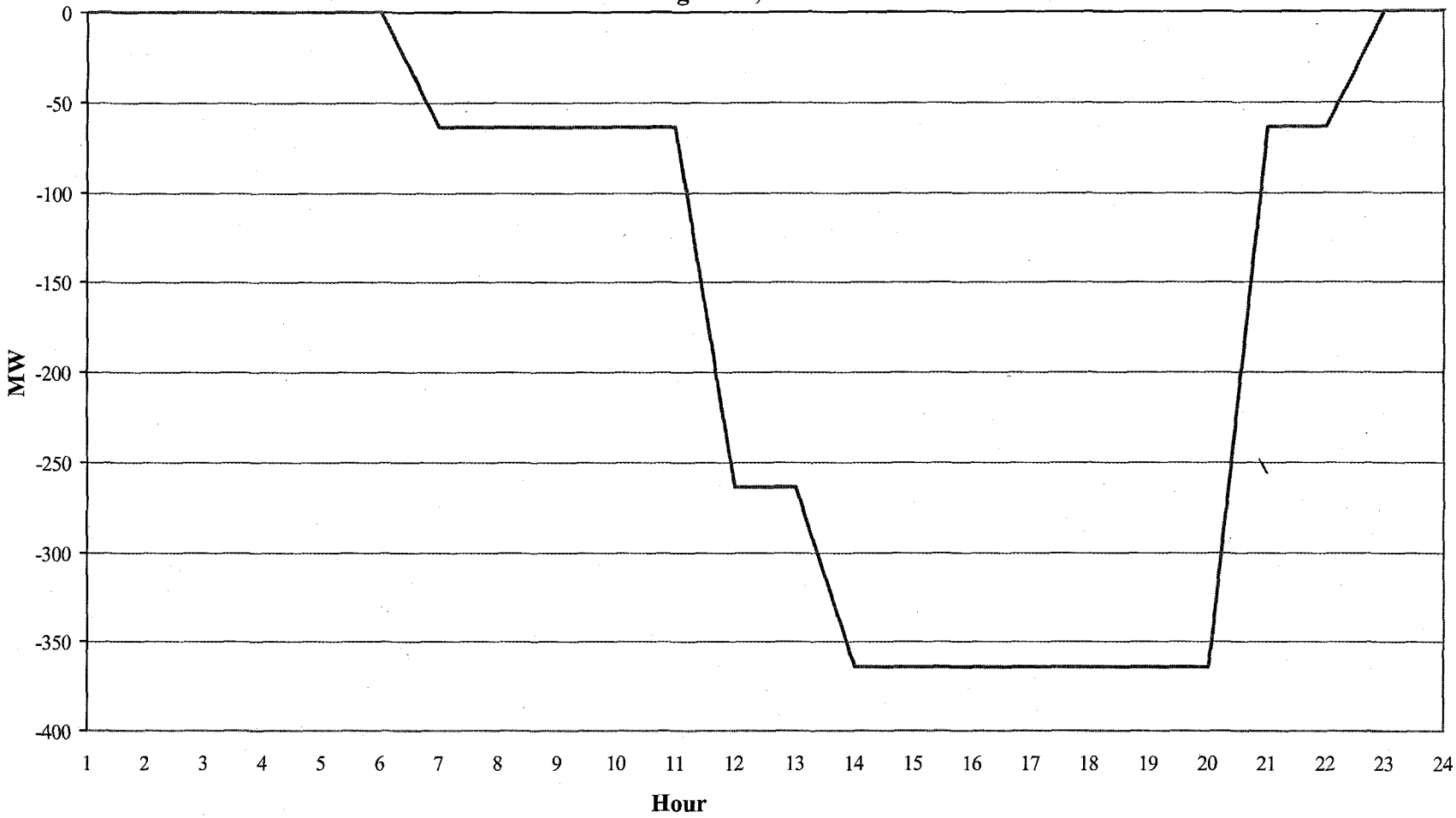
Figure D-8 (page 20 of 53)
Net PX Supply by PowerEX
August 23, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

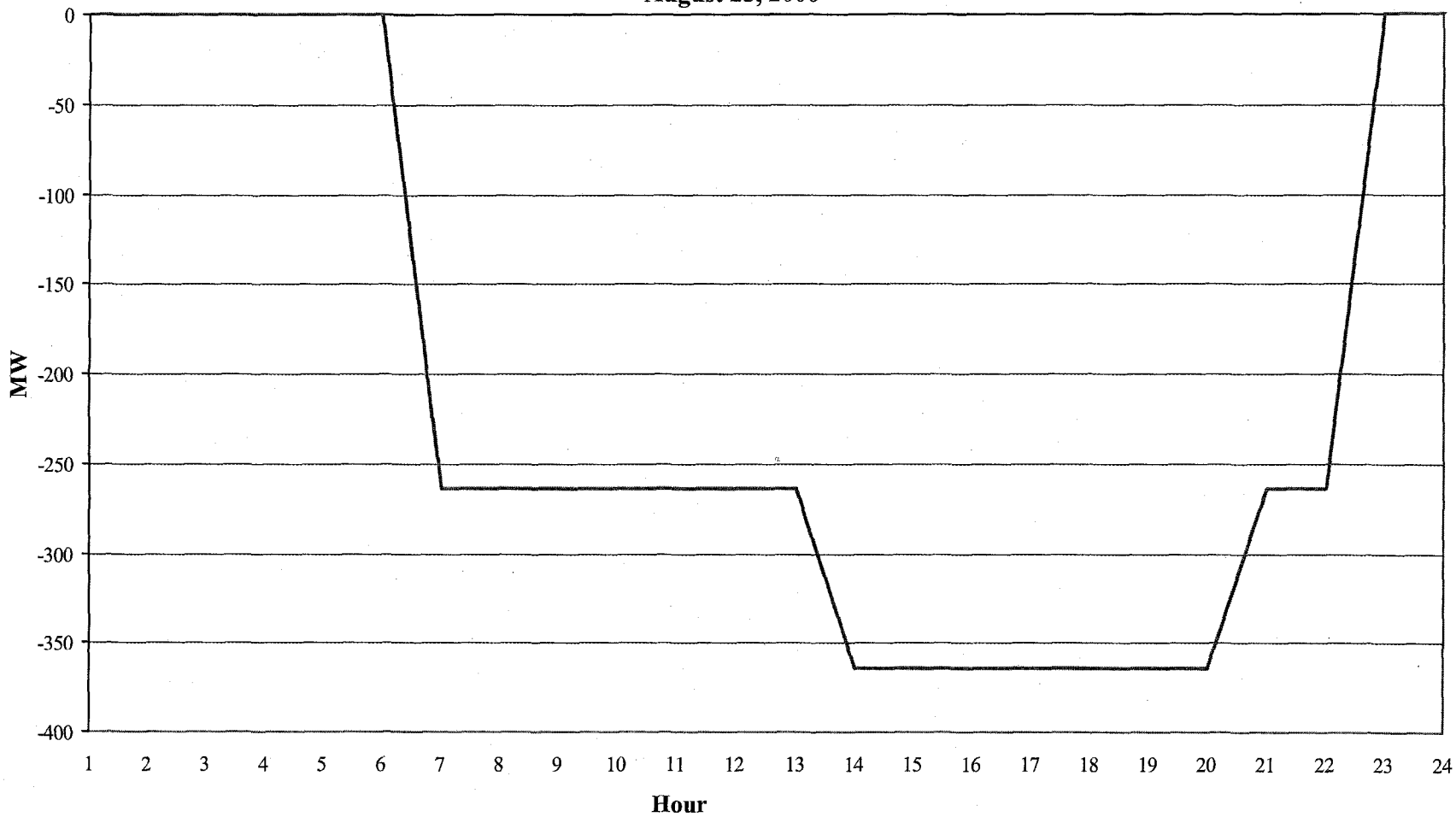
Figure D-8 (page 21 of 53)
Net PX Supply by PowerEX
August 24, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

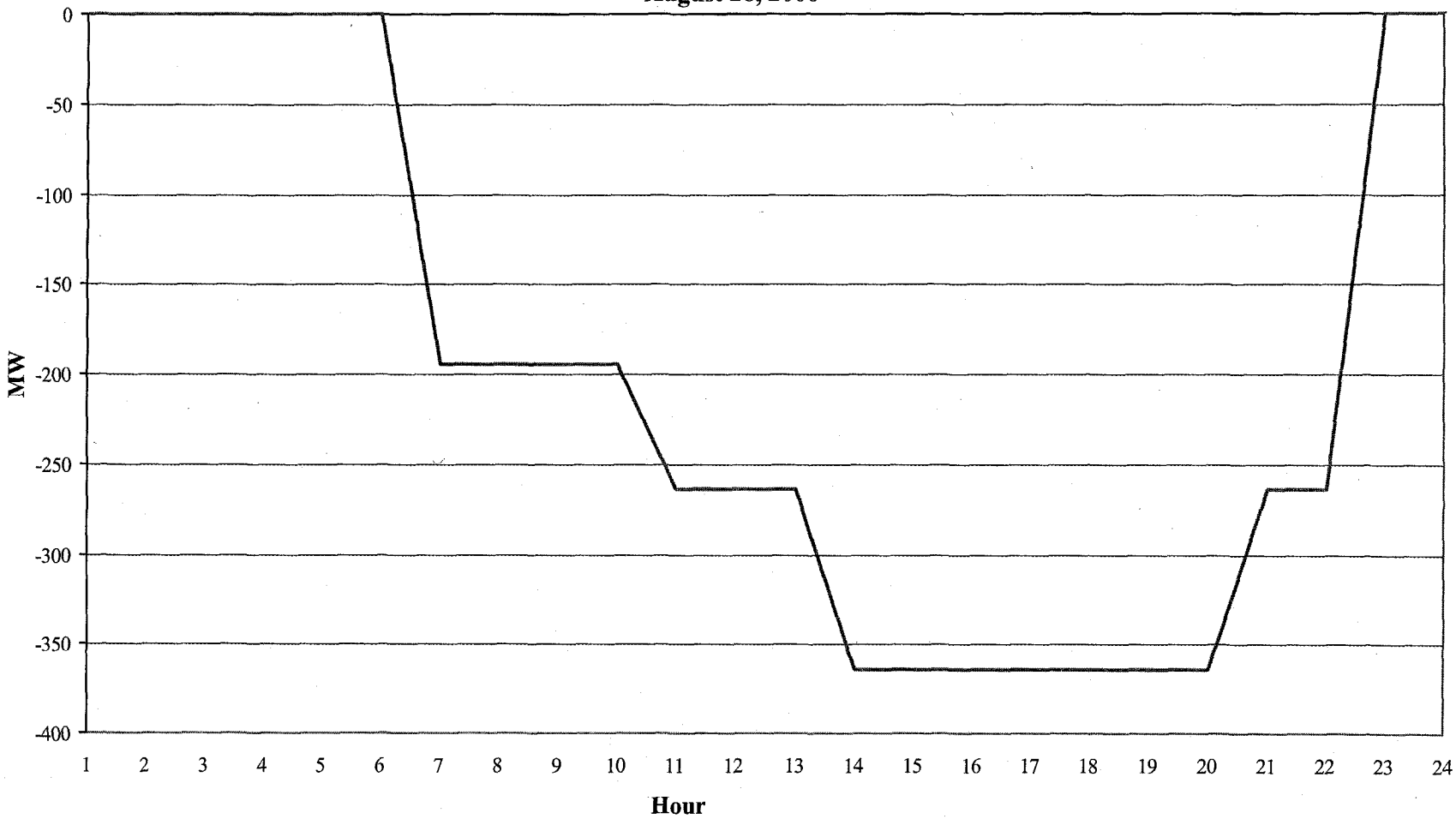
Figure D-8 (page 22 of 53)
Net PX Supply by PowerEX
August 25, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

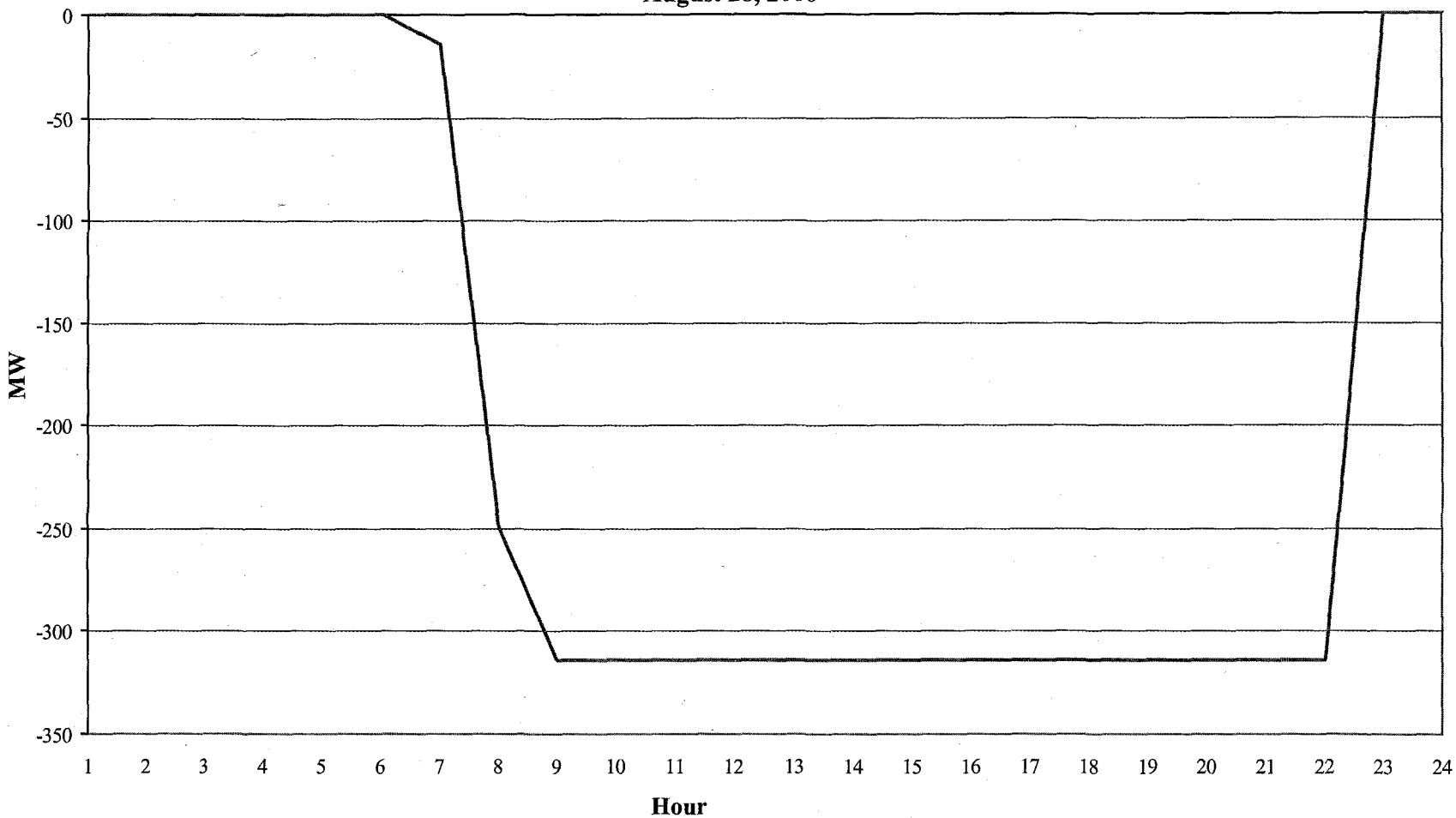
Figure D-8 (page 23 of 53)
Net PX Supply by PowerEX
August 26, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

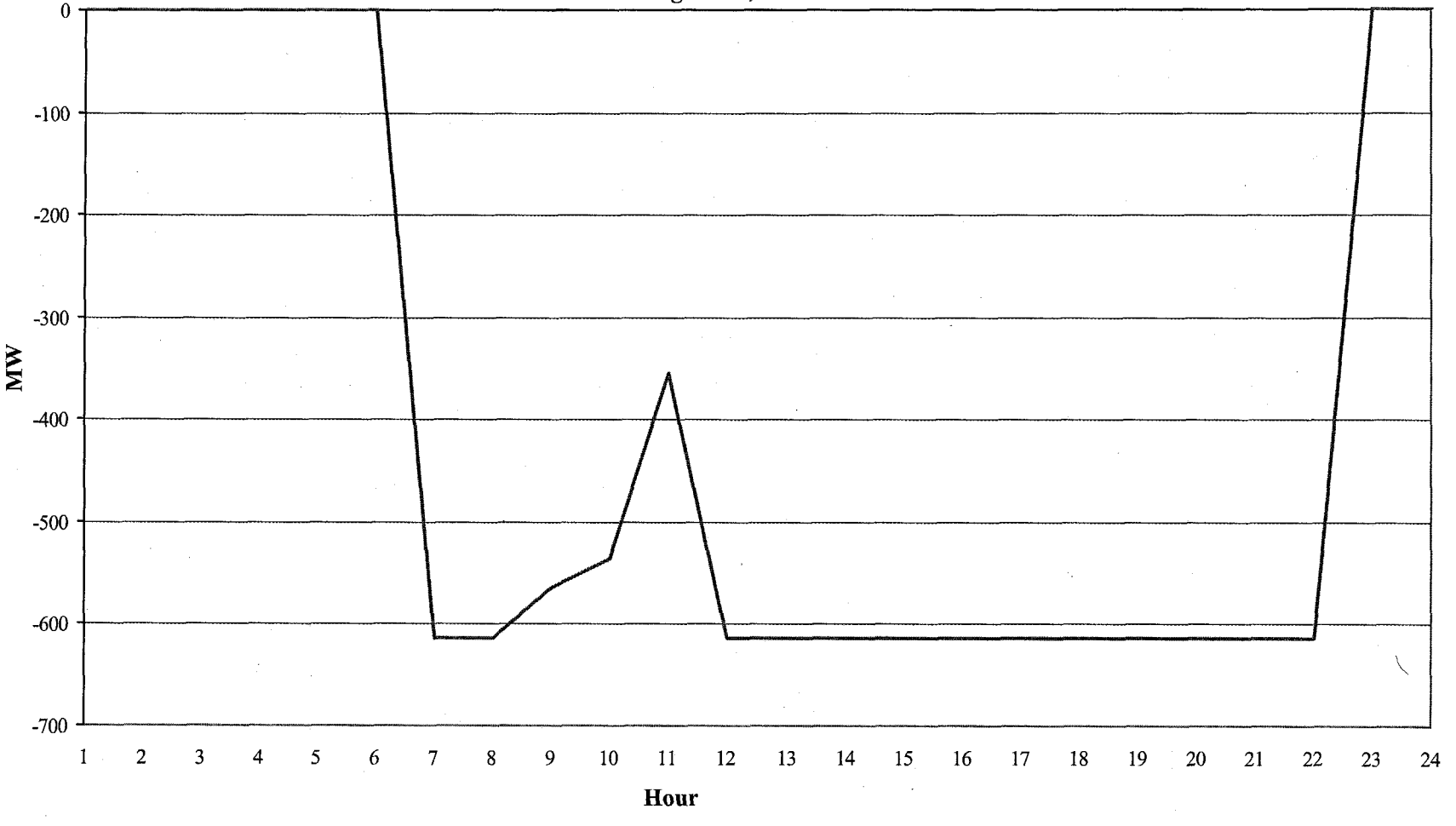
Figure D-8 (page 24 of 53)
Net PX Supply by PowerEX
August 28, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

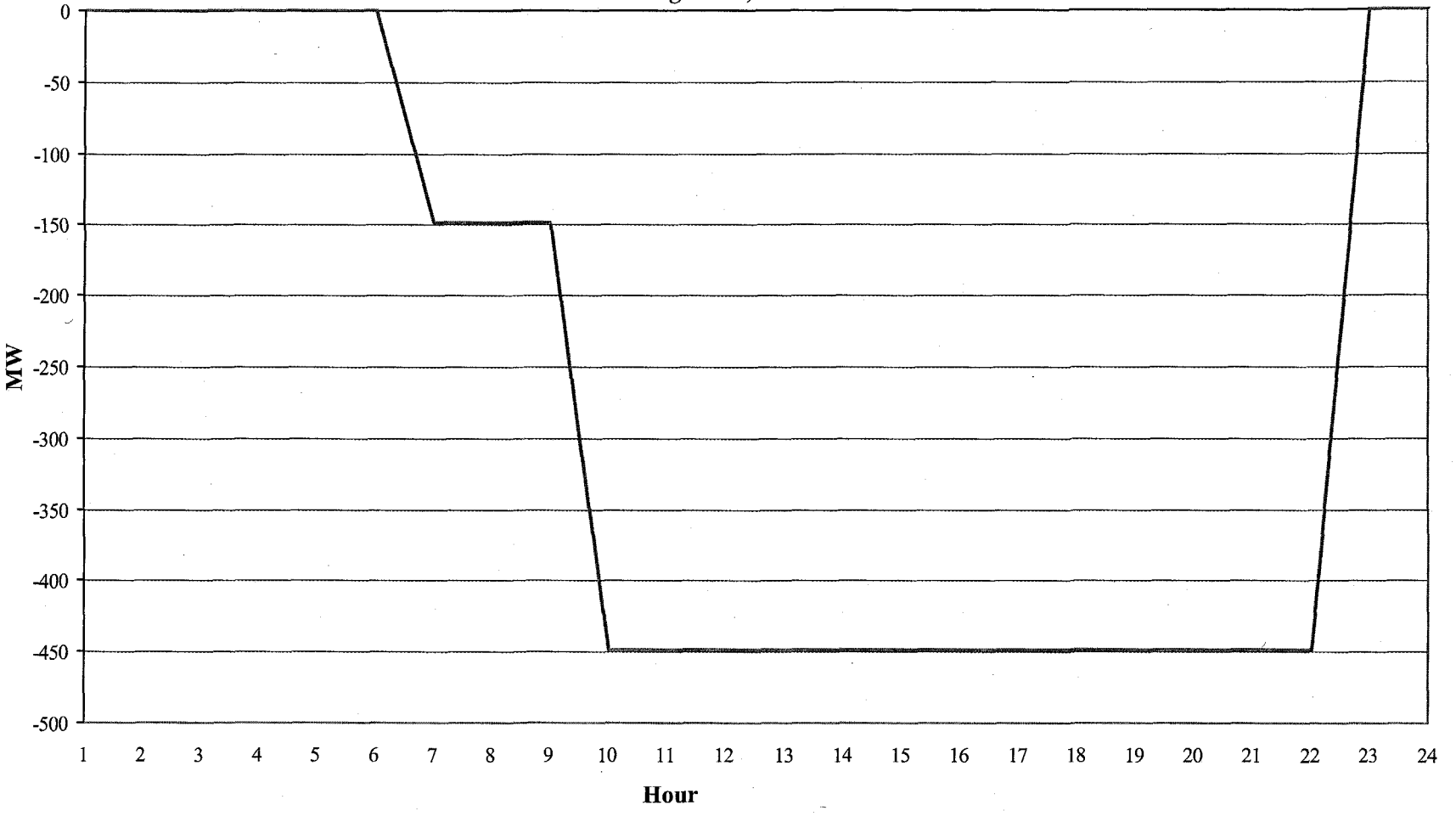
Figure D-8 (page 25 of 53)
Net PX Supply by PowerEX
August 29, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

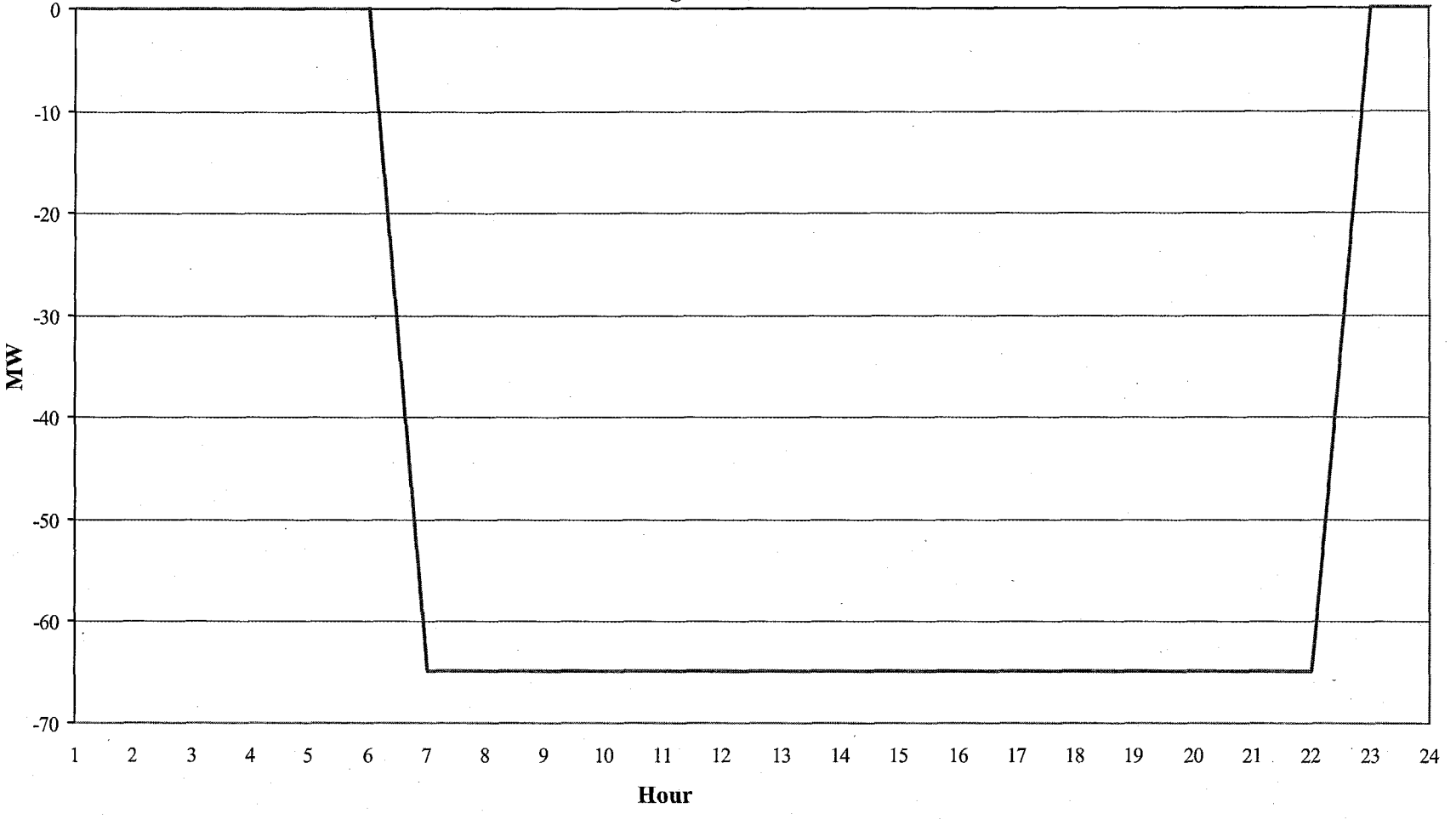
Figure D-8 (page 26 of 53)
Net PX Supply by PowerEX
August 30, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

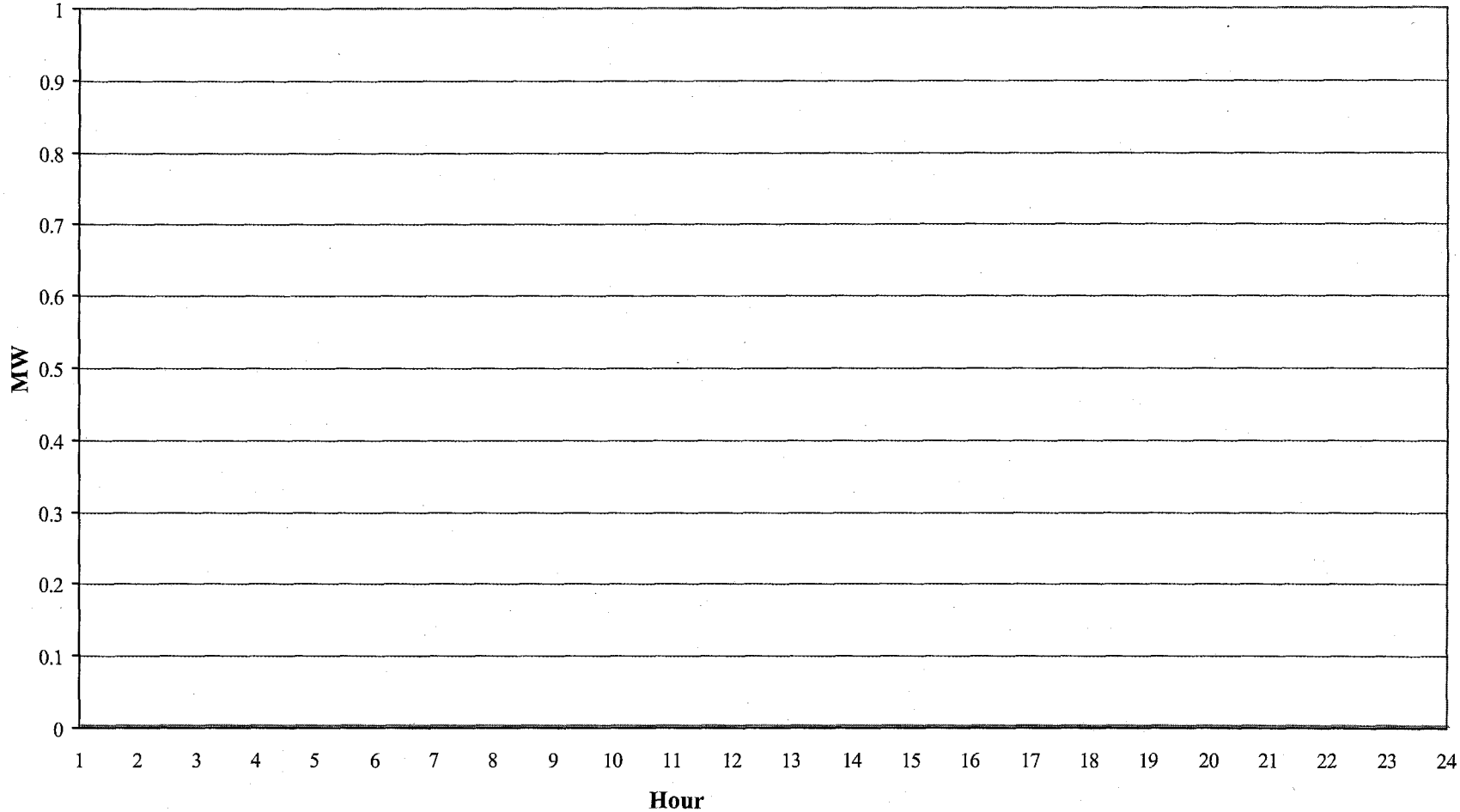
Figure D-8 (page 27 of 53)
Net PX Supply by PowerEX
August 31, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

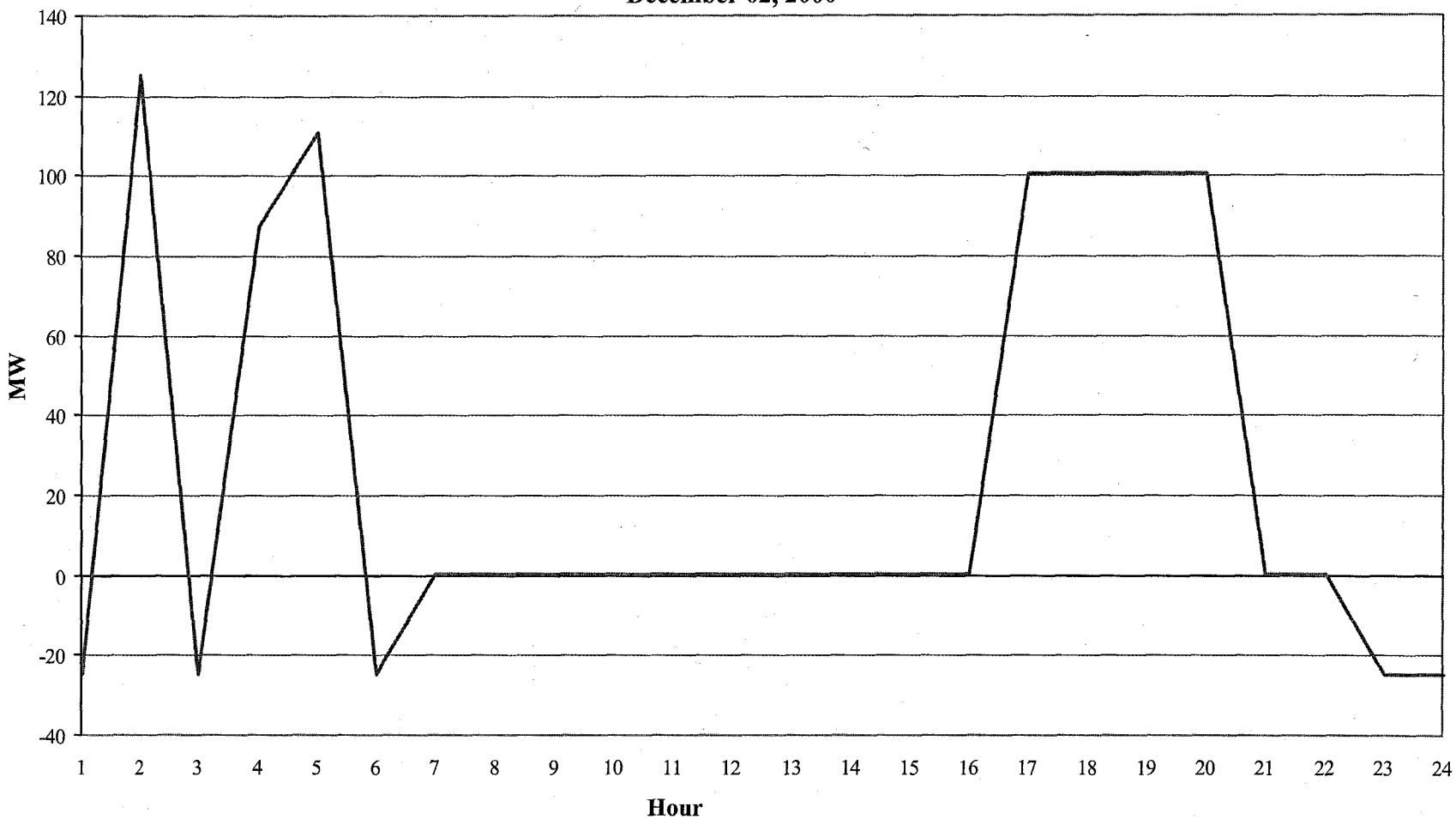
Figure D-8 (page 28 of 53)
Net PX Supply by PowerEX
December 01, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

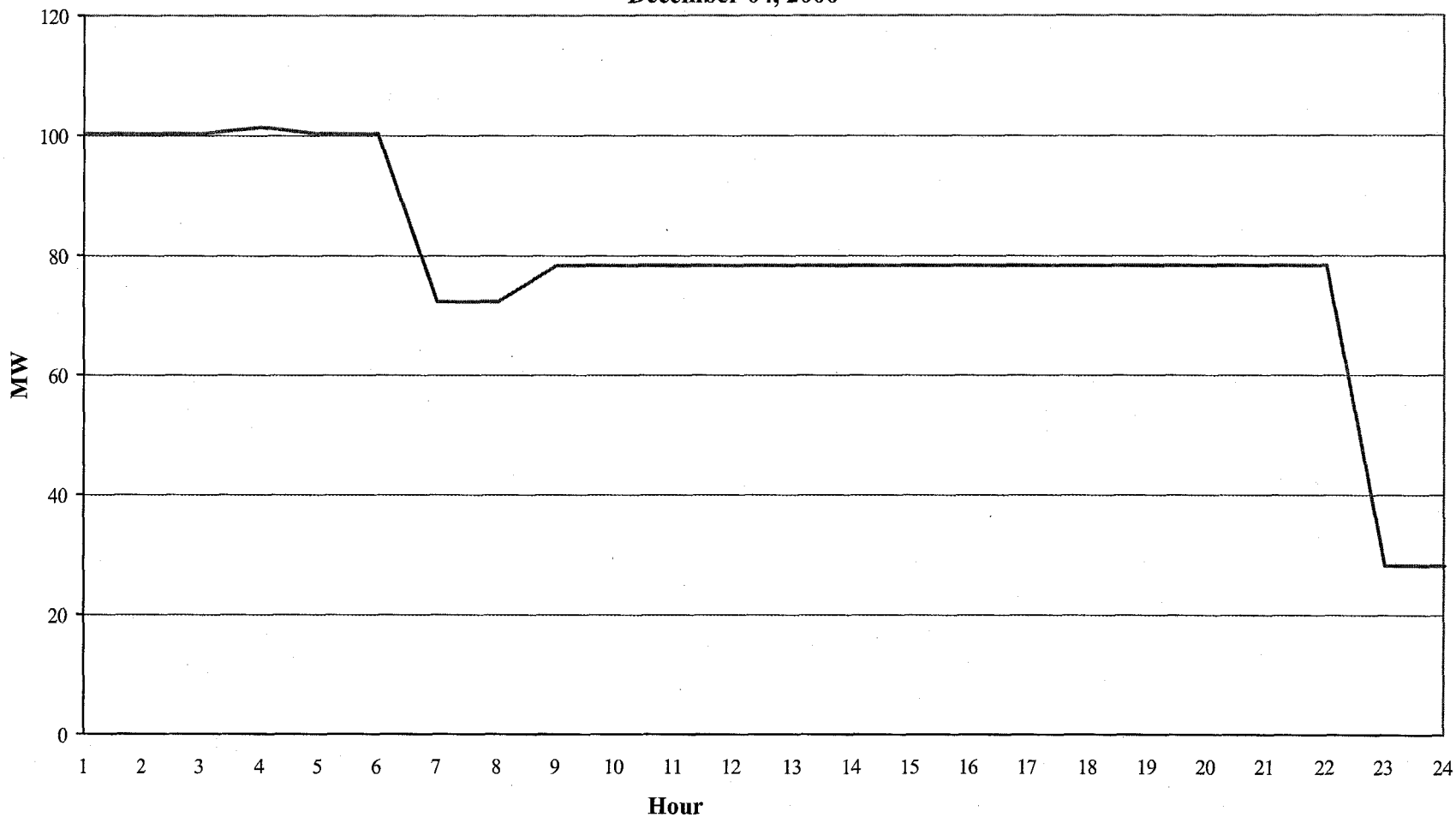
Figure D-8 (page 29 of 53)
Net PX Supply by PowerEX
December 02, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

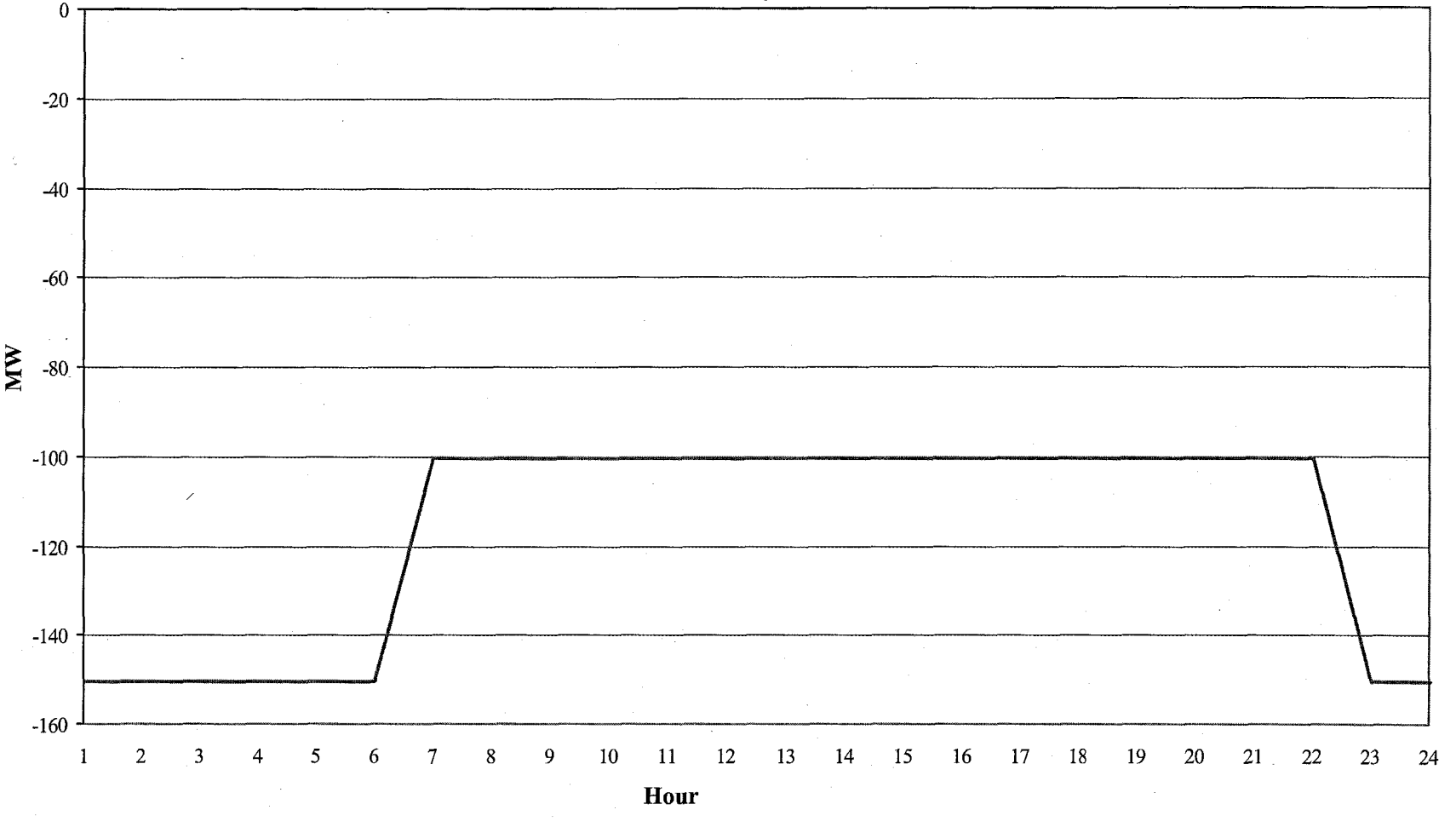
Figure D-8 (page 30 of 53)
Net PX Supply by PowerEX
December 04, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

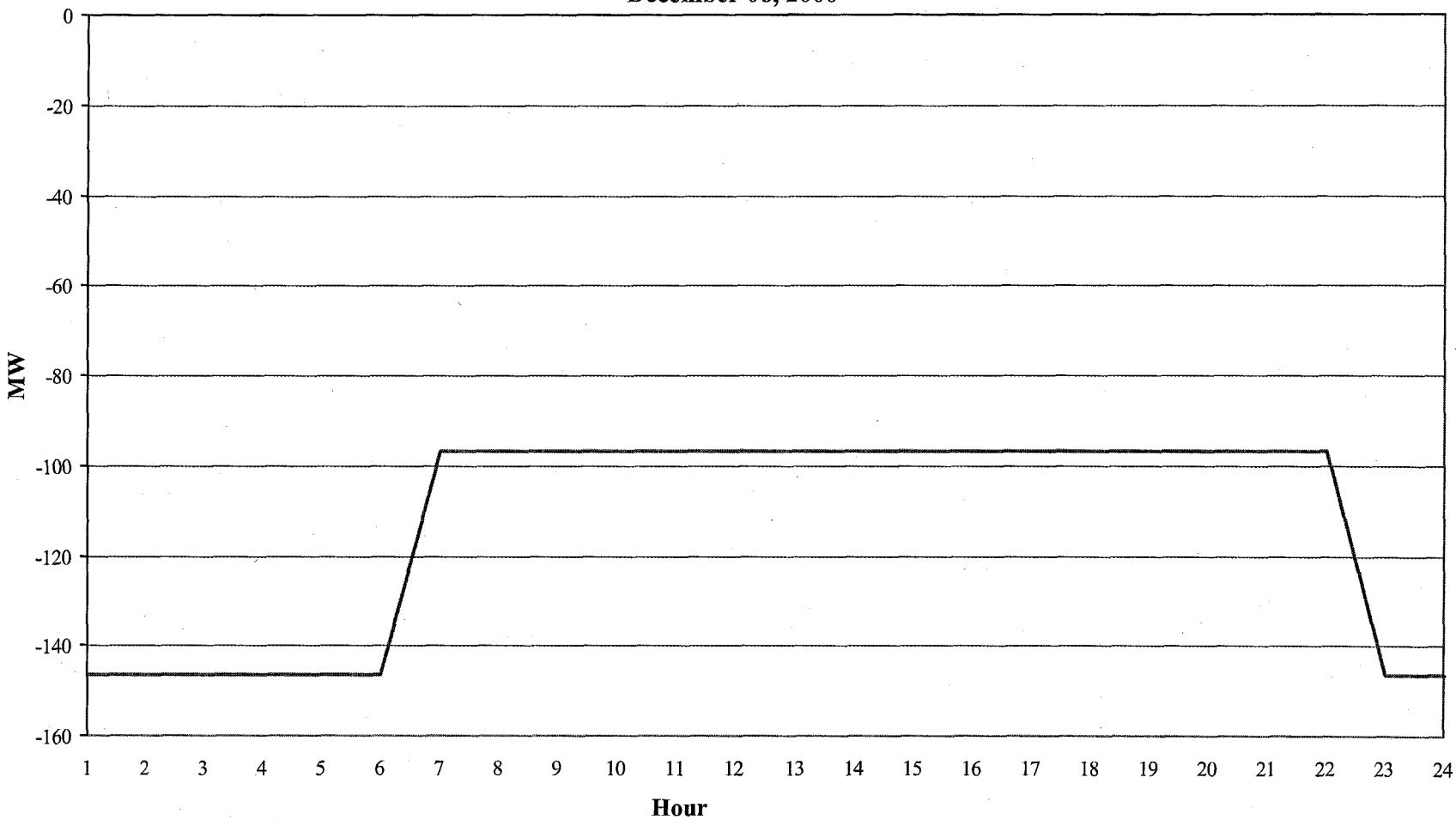
Figure D-8 (page 31 of 53)
Net PX Supply by PowerEX
December 05, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

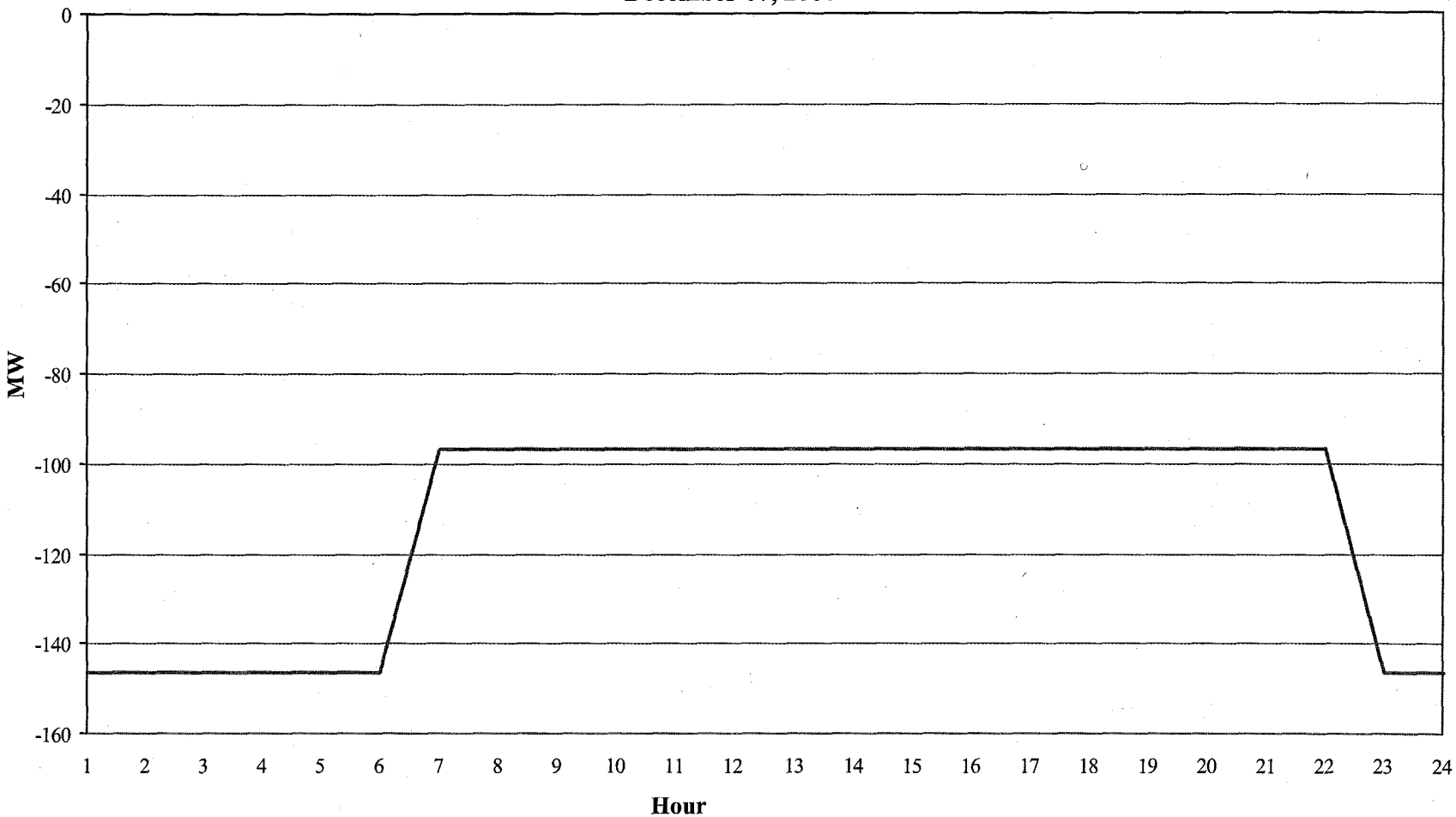
Figure D-8 (page 32 of 53)
Net PX Supply by PowerEX
December 06, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

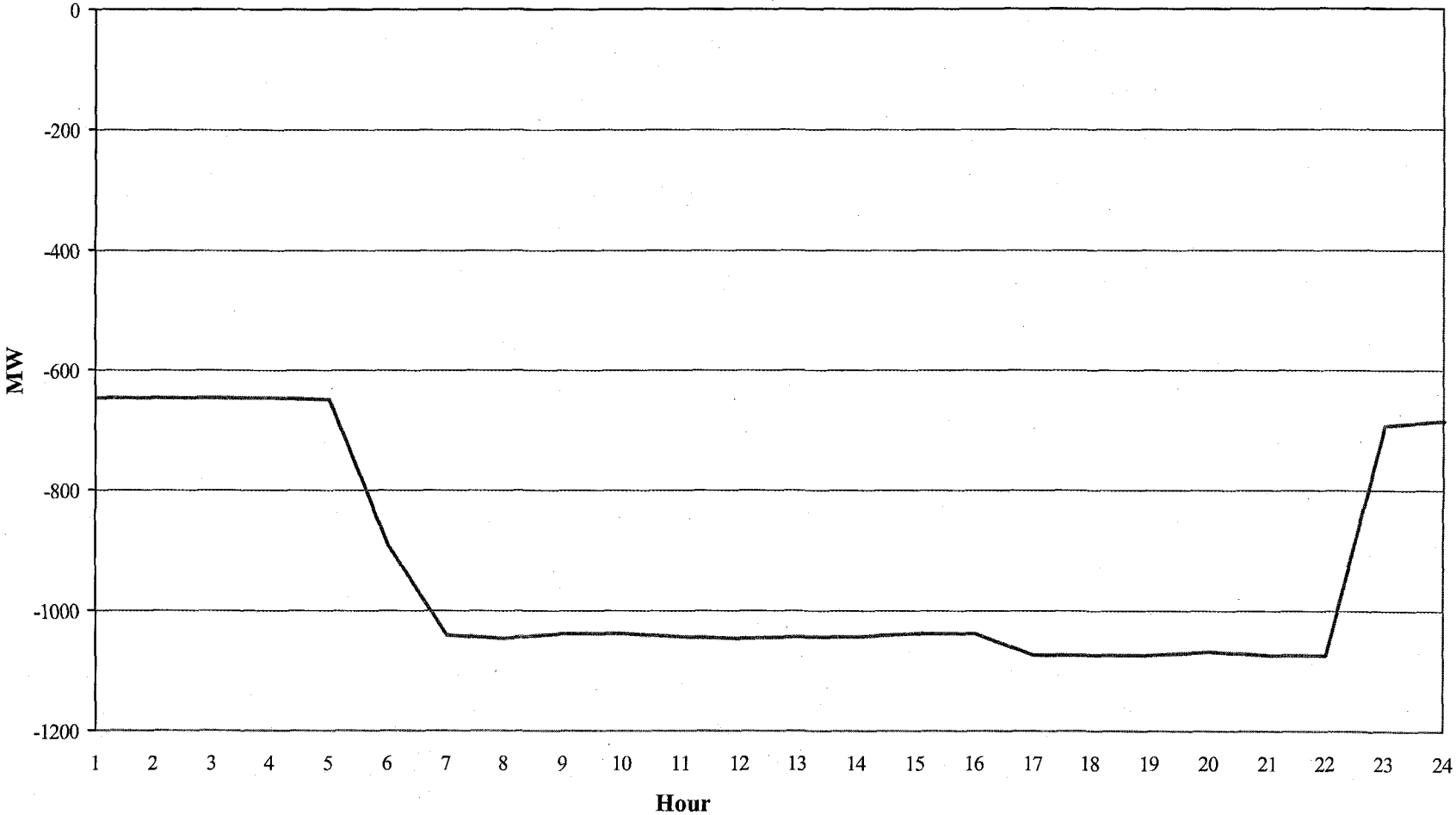
Figure D-8 (page 33 of 53)
Net PX Supply by PowerEX
December 07, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

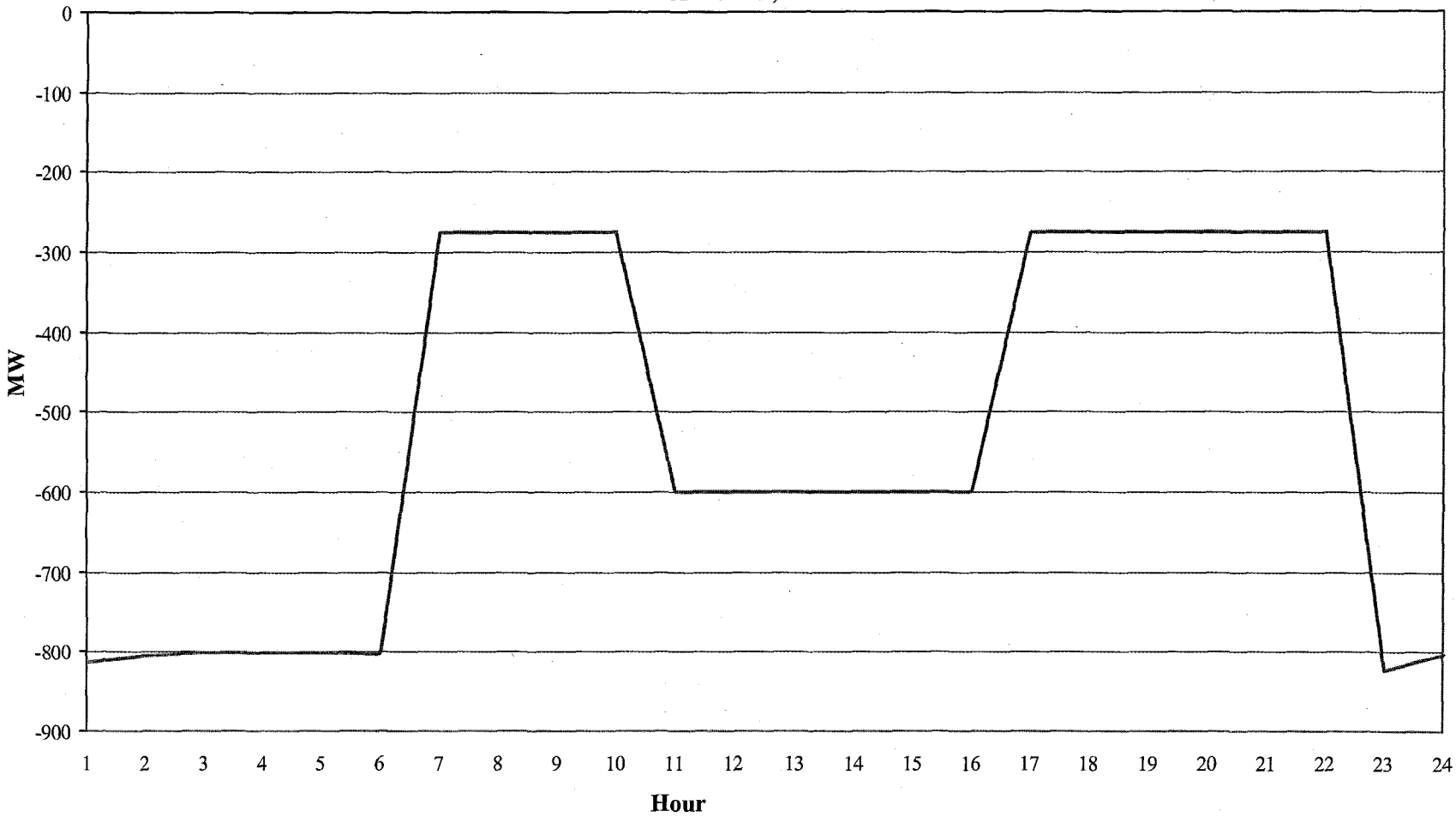
Figure D-8 (page 34 of 53)
Net PX Supply by PowerEX
December 08, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

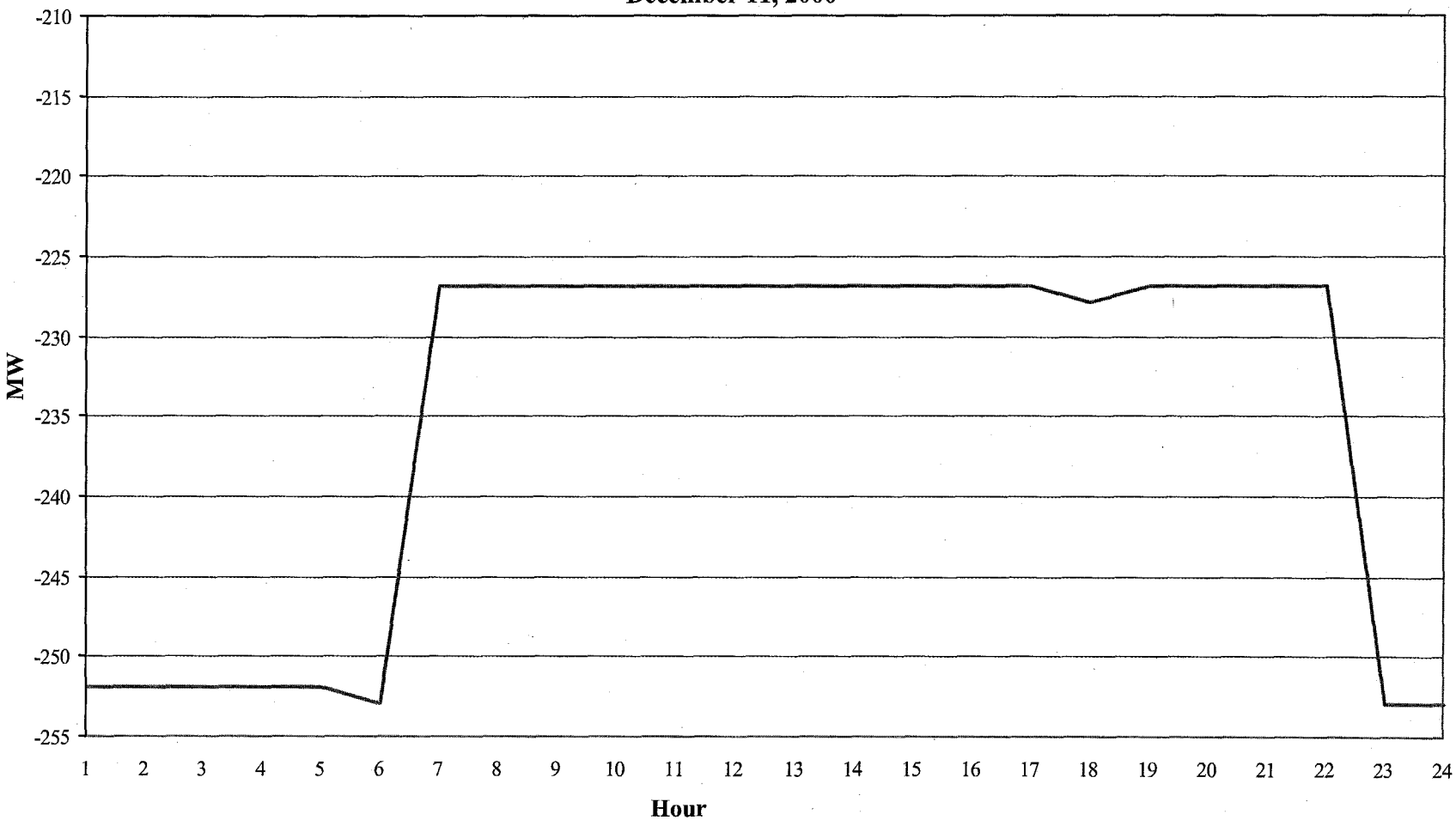
Figure D-8 (page 35 of 53)
Net PX Supply by PowerEX
December 09, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

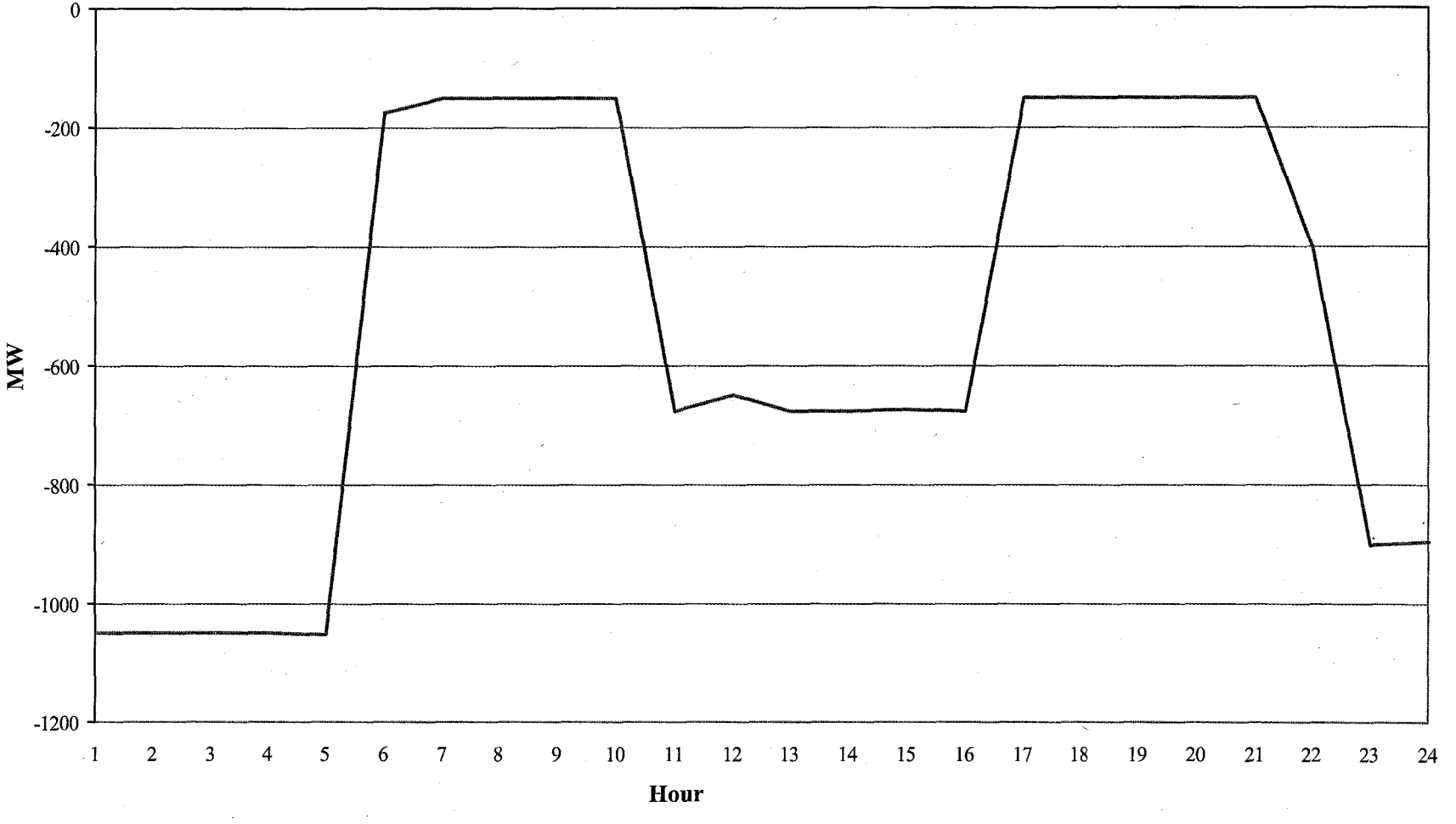
Figure D-8 (page 36 of 53)
Net PX Supply by PowerEX
December 11, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

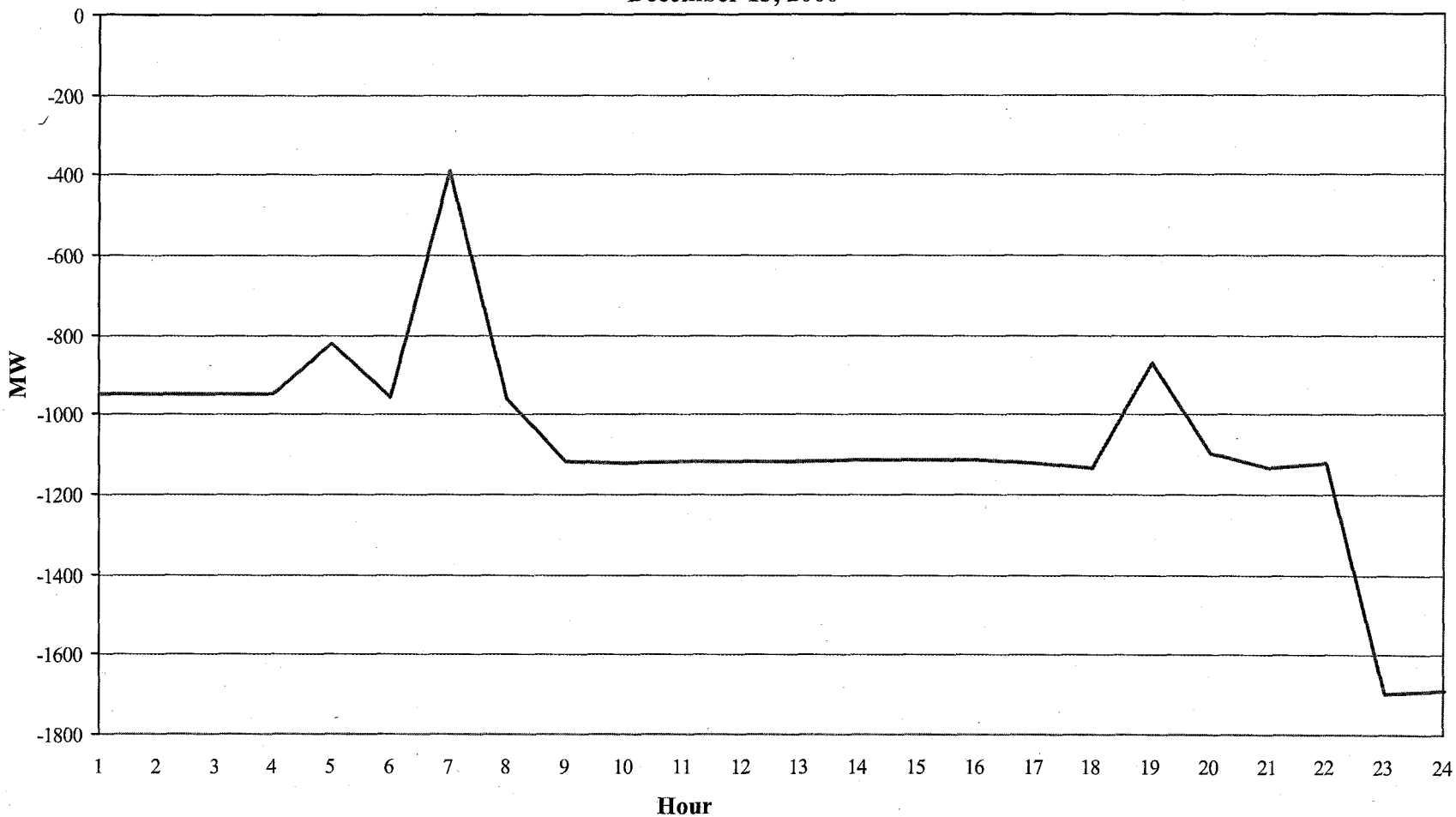
Figure D-8 (page 37 of 53)
Net PX Supply by PowerEX
December 12, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

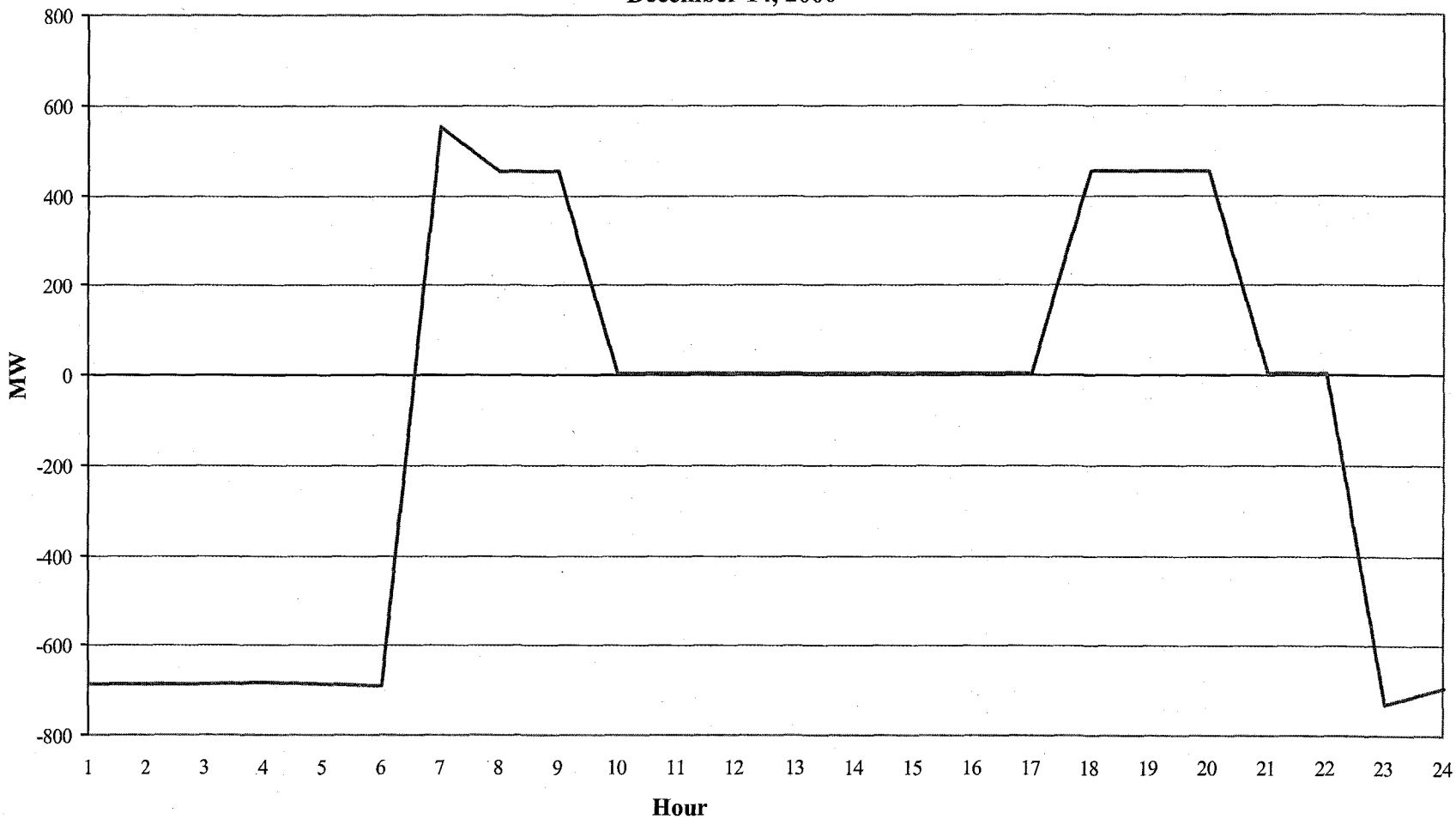
Figure D-8 (page 38 of 53)
Net PX Supply by PowerEX
December 13, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

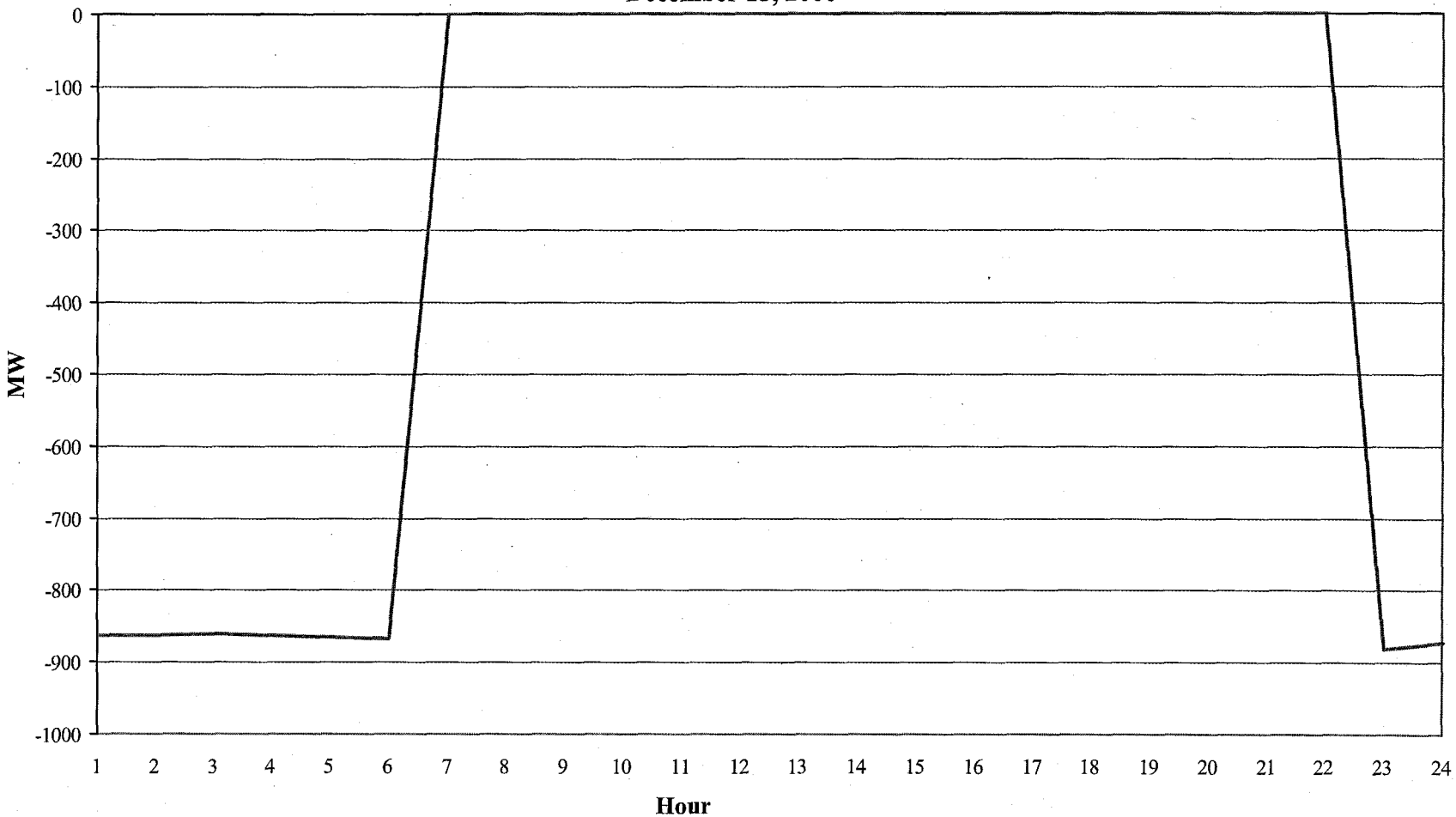
Figure D-8 (page 39 of 53)
Net PX Supply by PowerEX
December 14, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

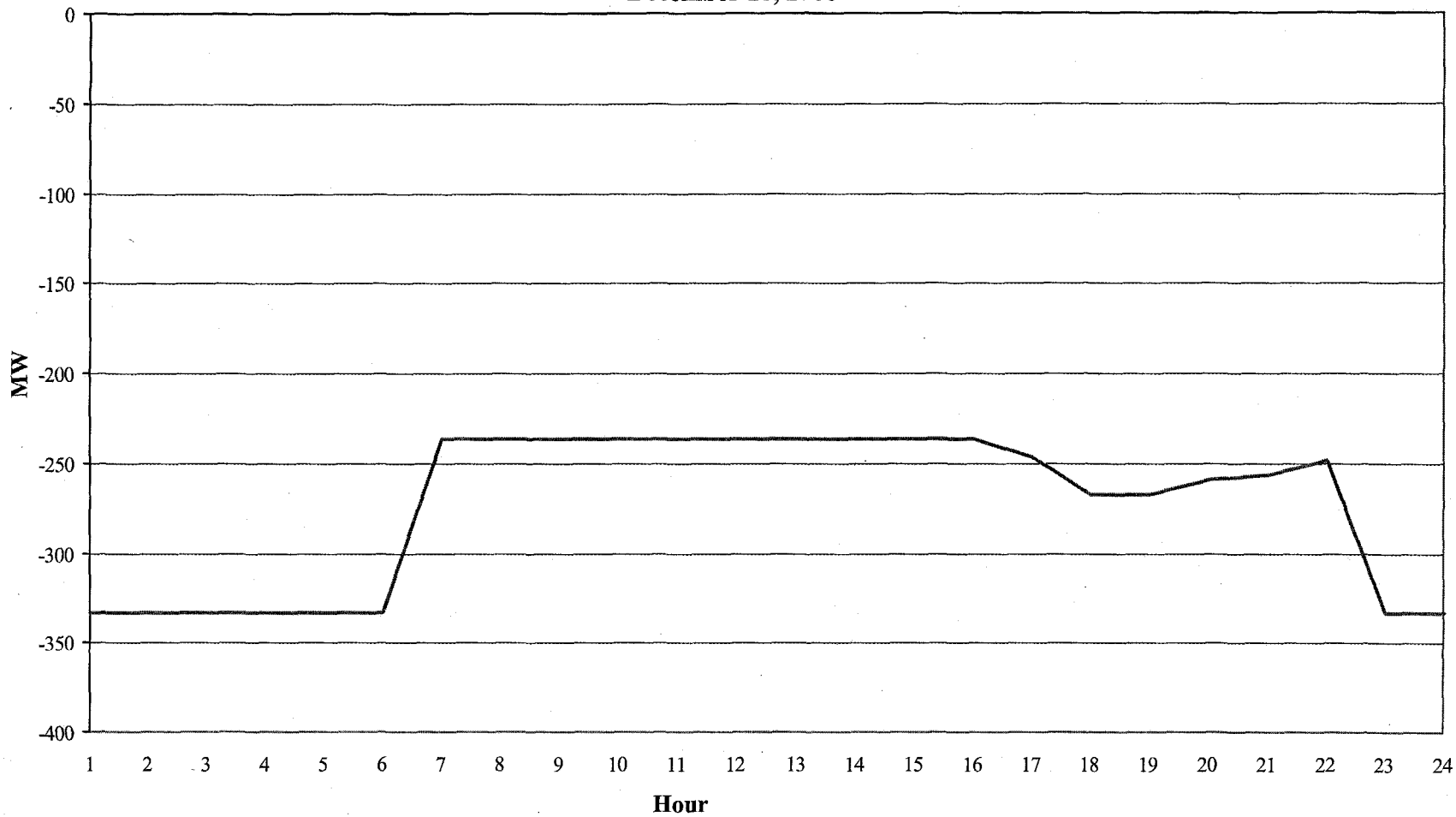
Figure D-8 (page 40 of 53)
Net PX Supply by PowerEX
December 15, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

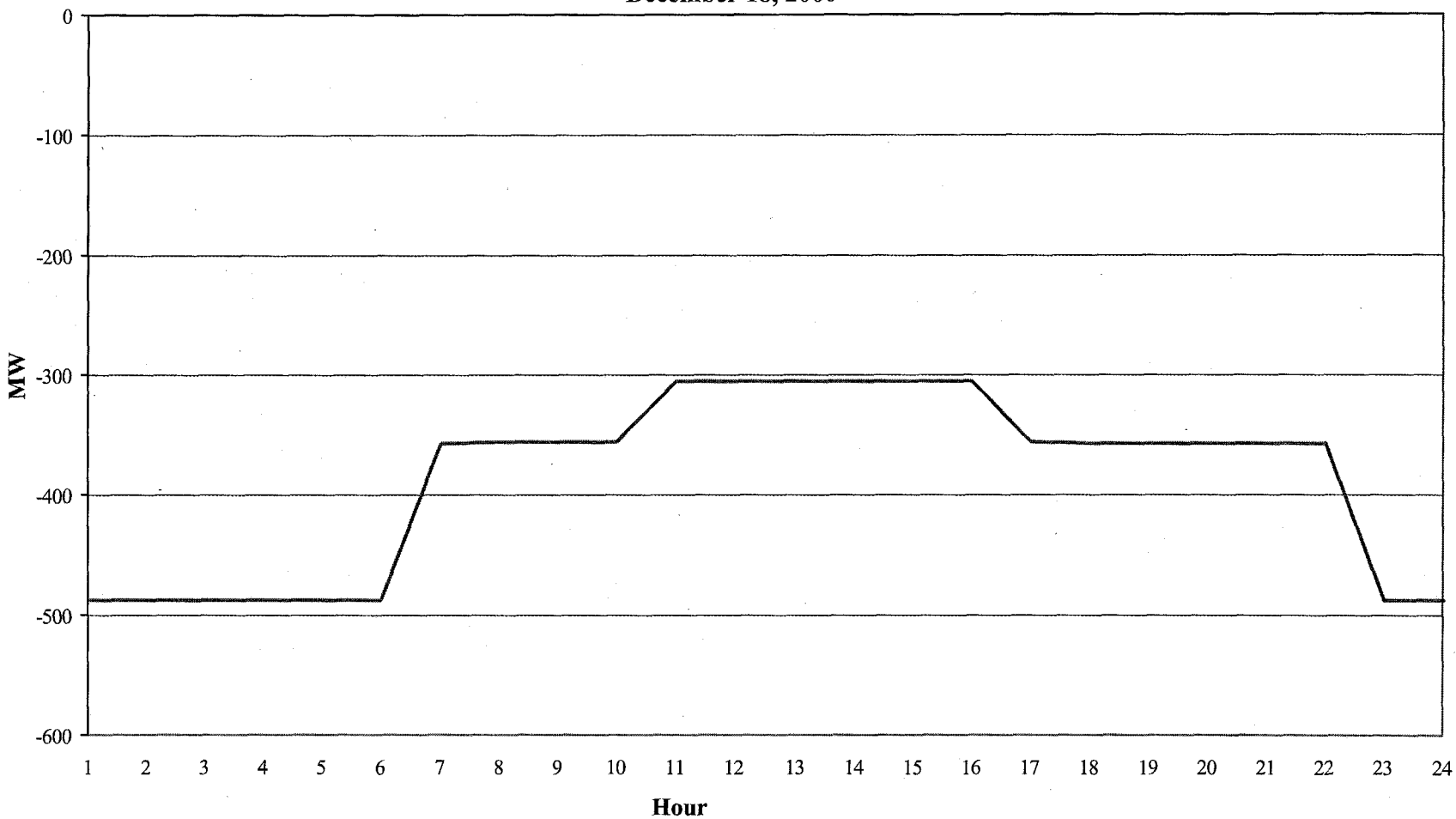
Figure D-8 (page 41 of 53)
Net PX Supply by PowerEX
December 16, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

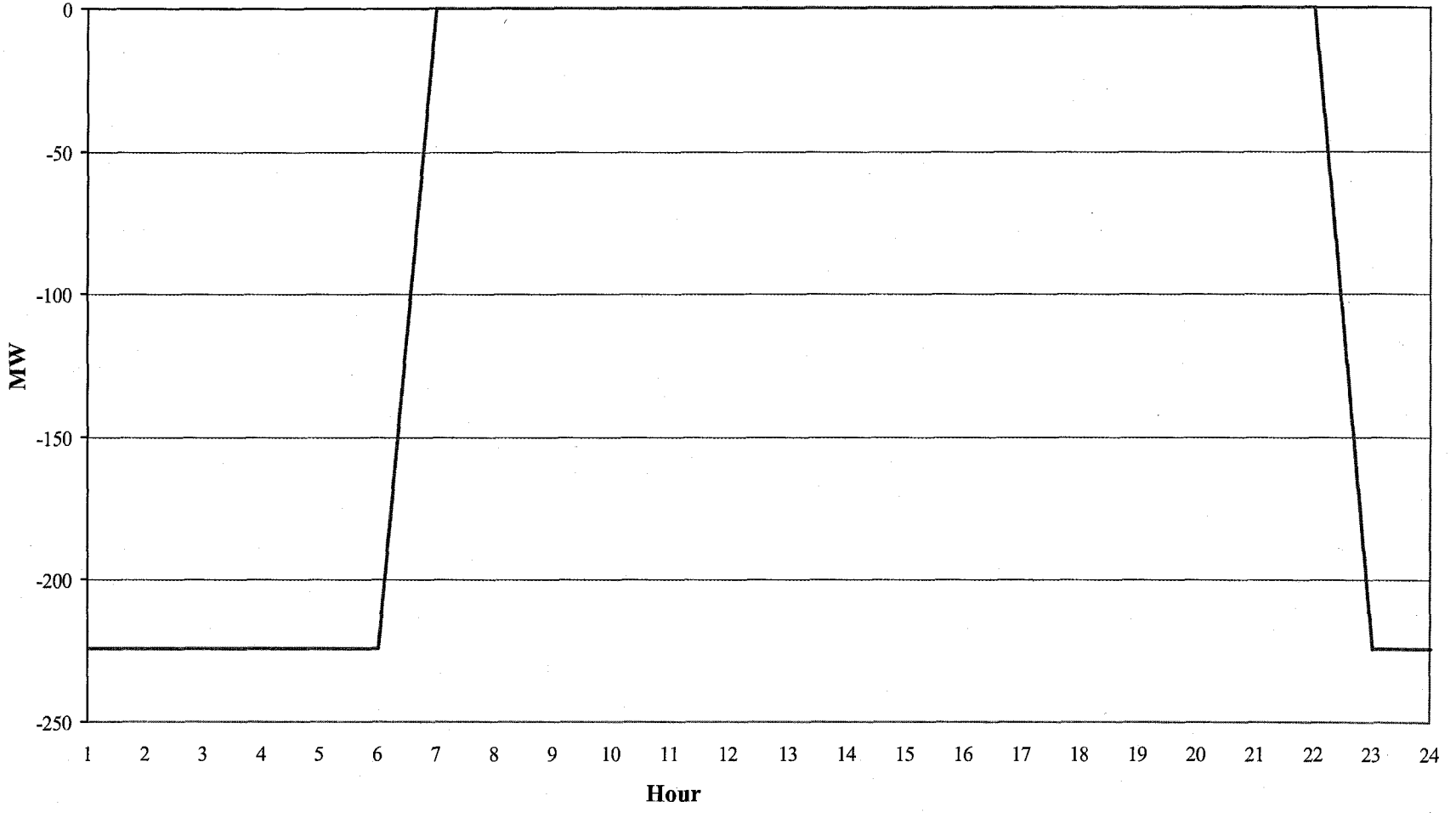
Figure D-8 (page 42 of 53)
Net PX Supply by PowerEX
December 18, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

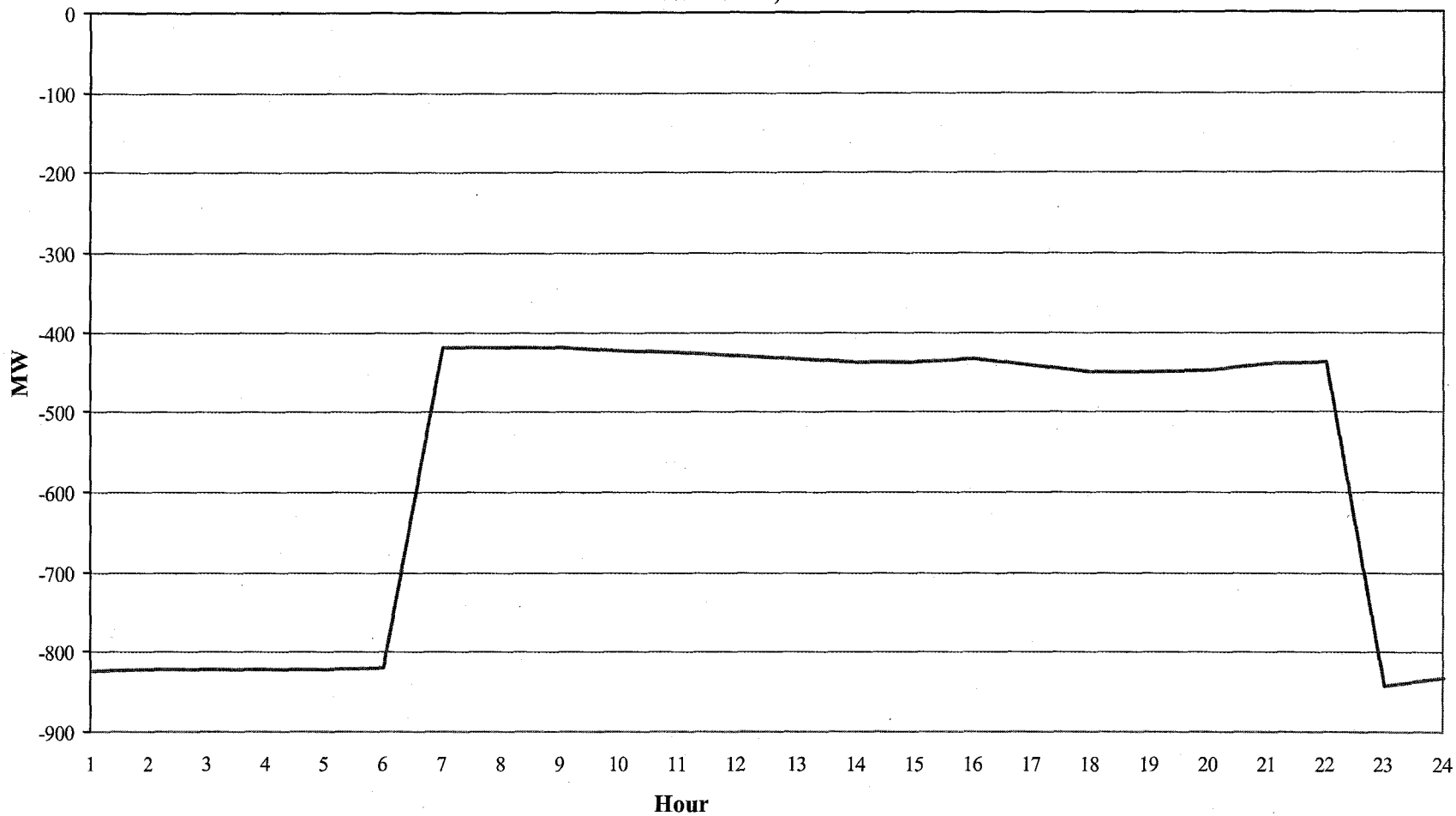
Figure D-8 (page 43 of 53)
Net PX Supply by PowerEX
December 19, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

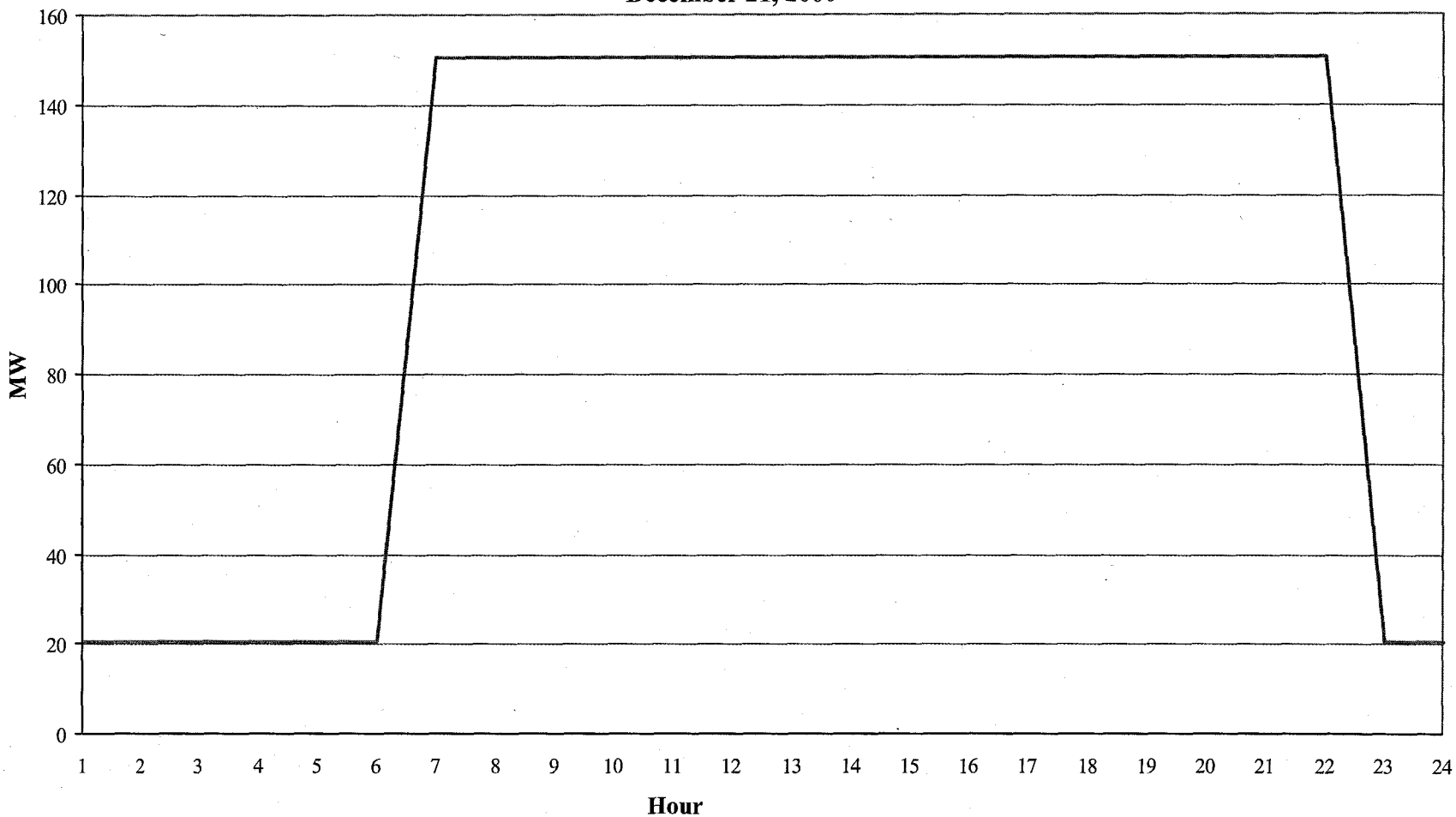
Figure D-8 (page 44 of 53)
Net PX Supply by PowerEX
December 20, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

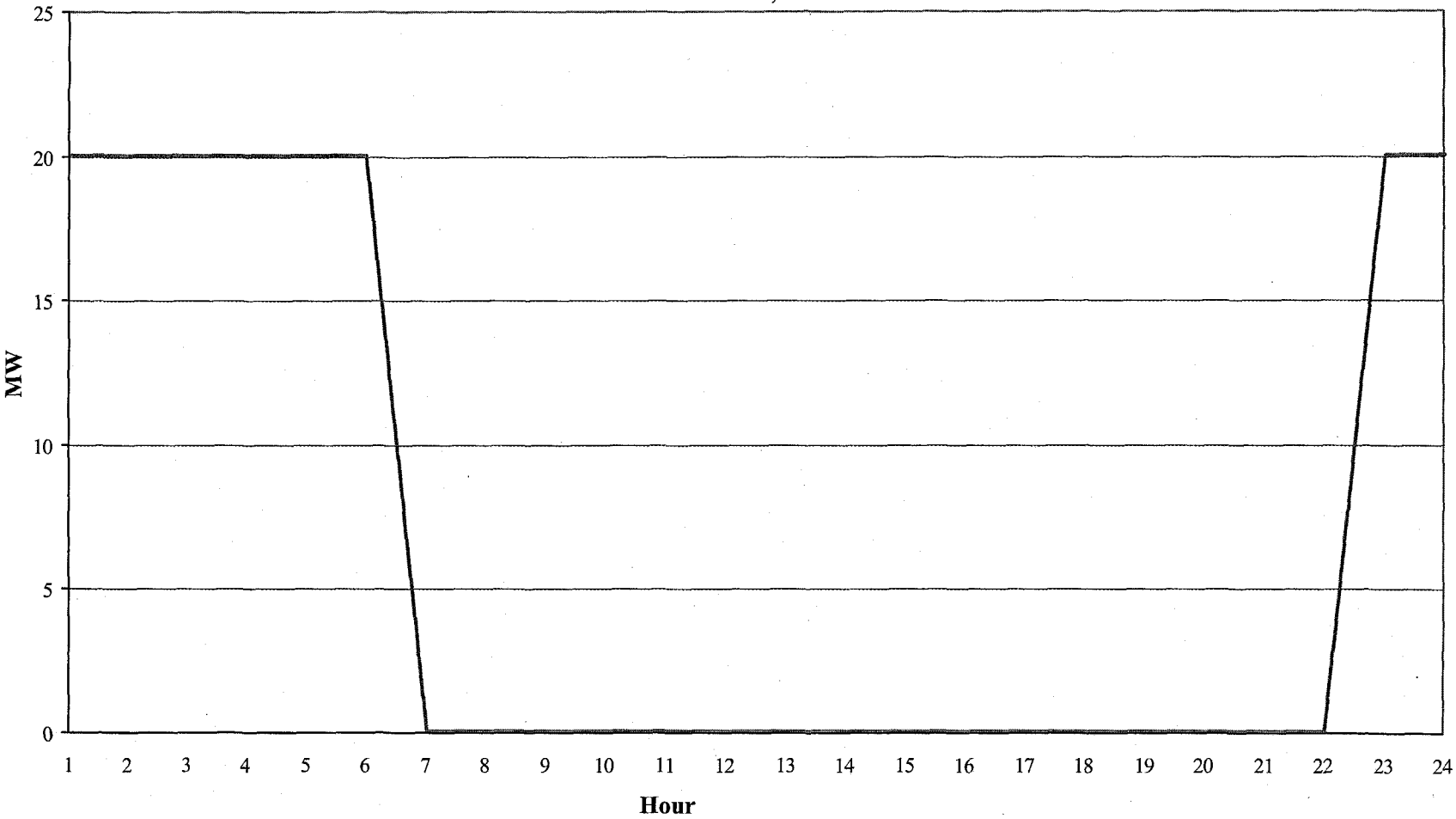
Figure D-8 (page 45 of 53)
Net PX Supply by PowerEX
December 21, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

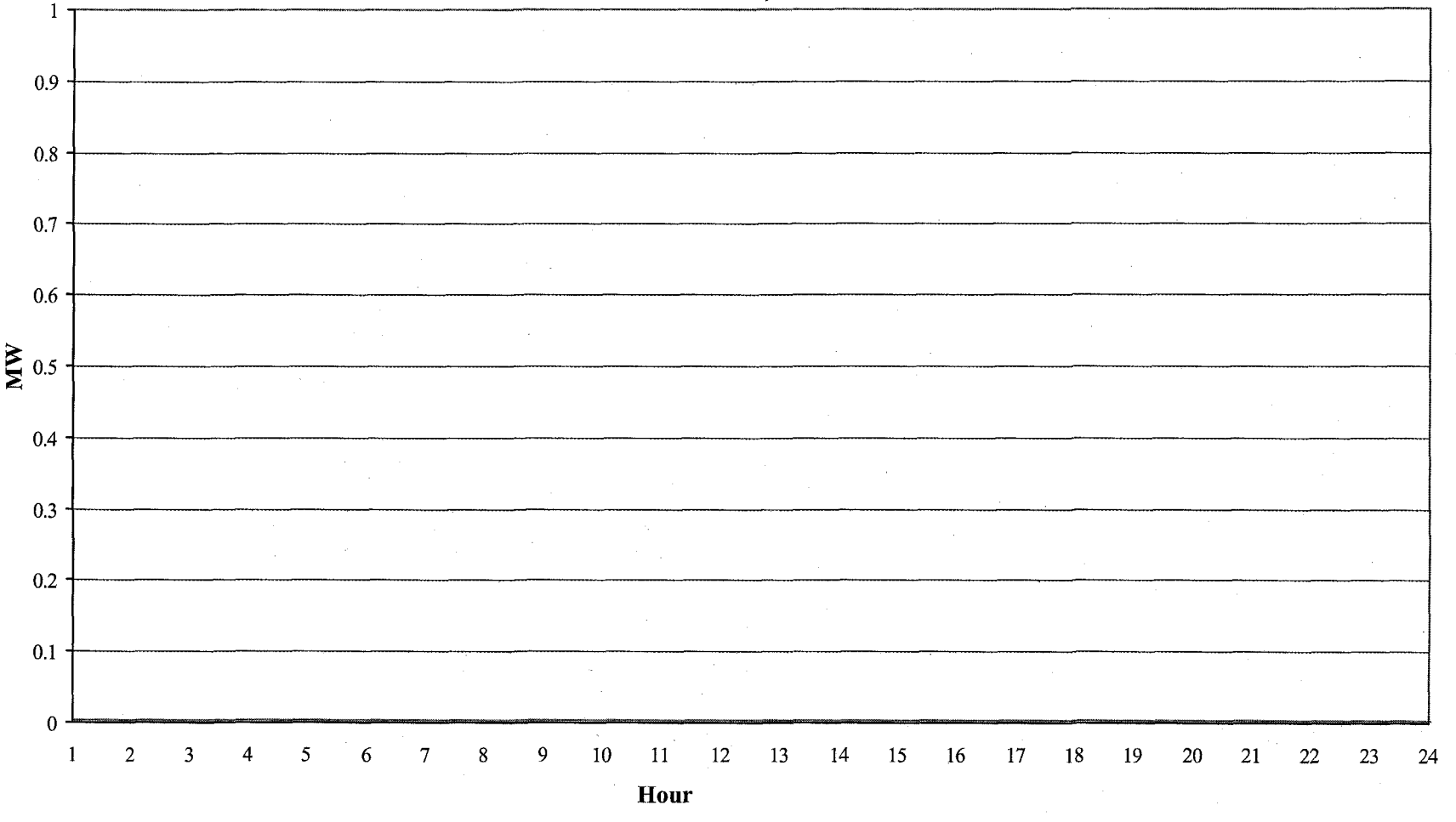
Figure D-8 (page 46 of 53)
Net PX Supply by PowerEX
December 22, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

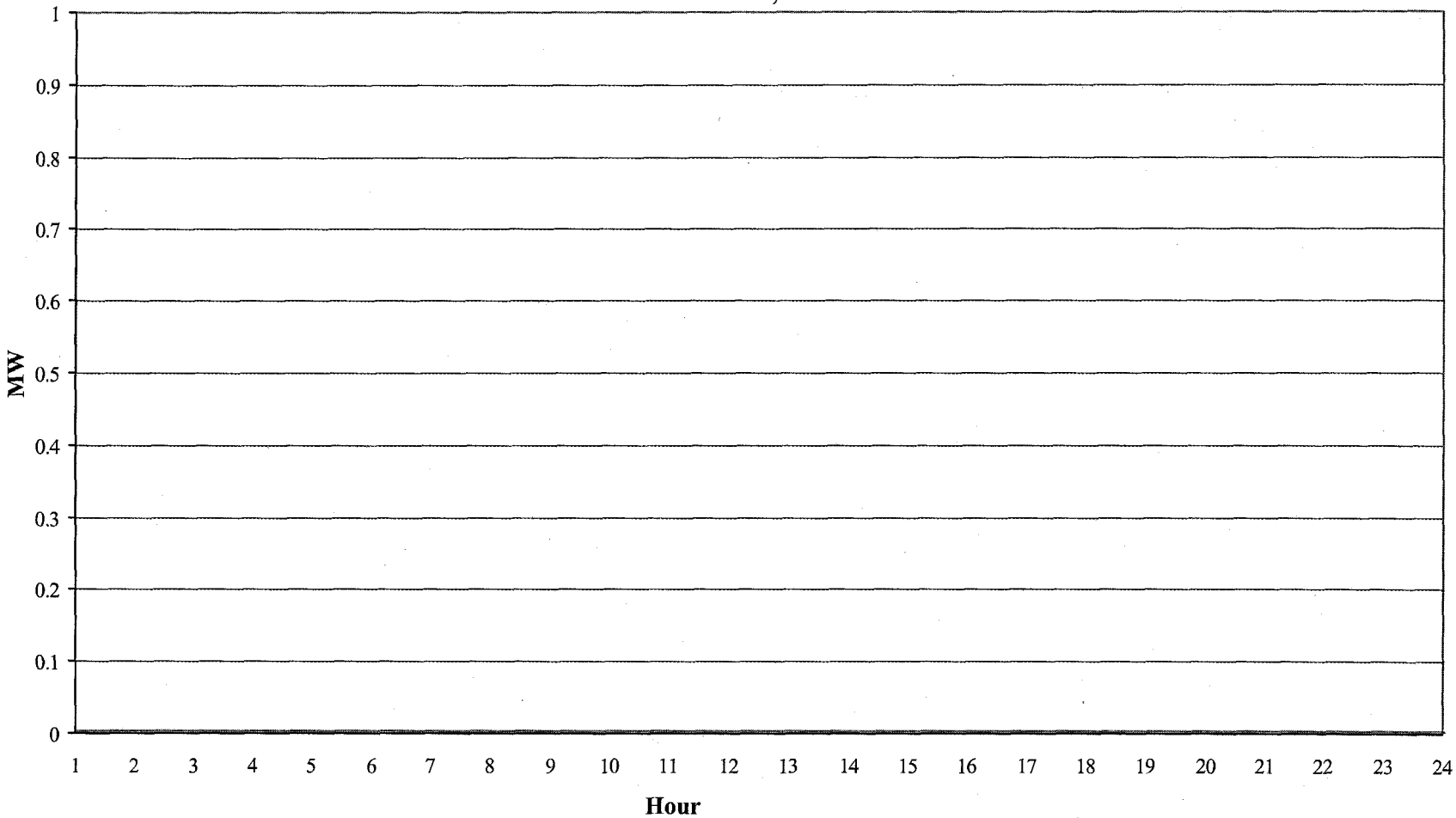
Figure D-8 (page 47 of 53)
Net PX Supply by PowerEX
December 23, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

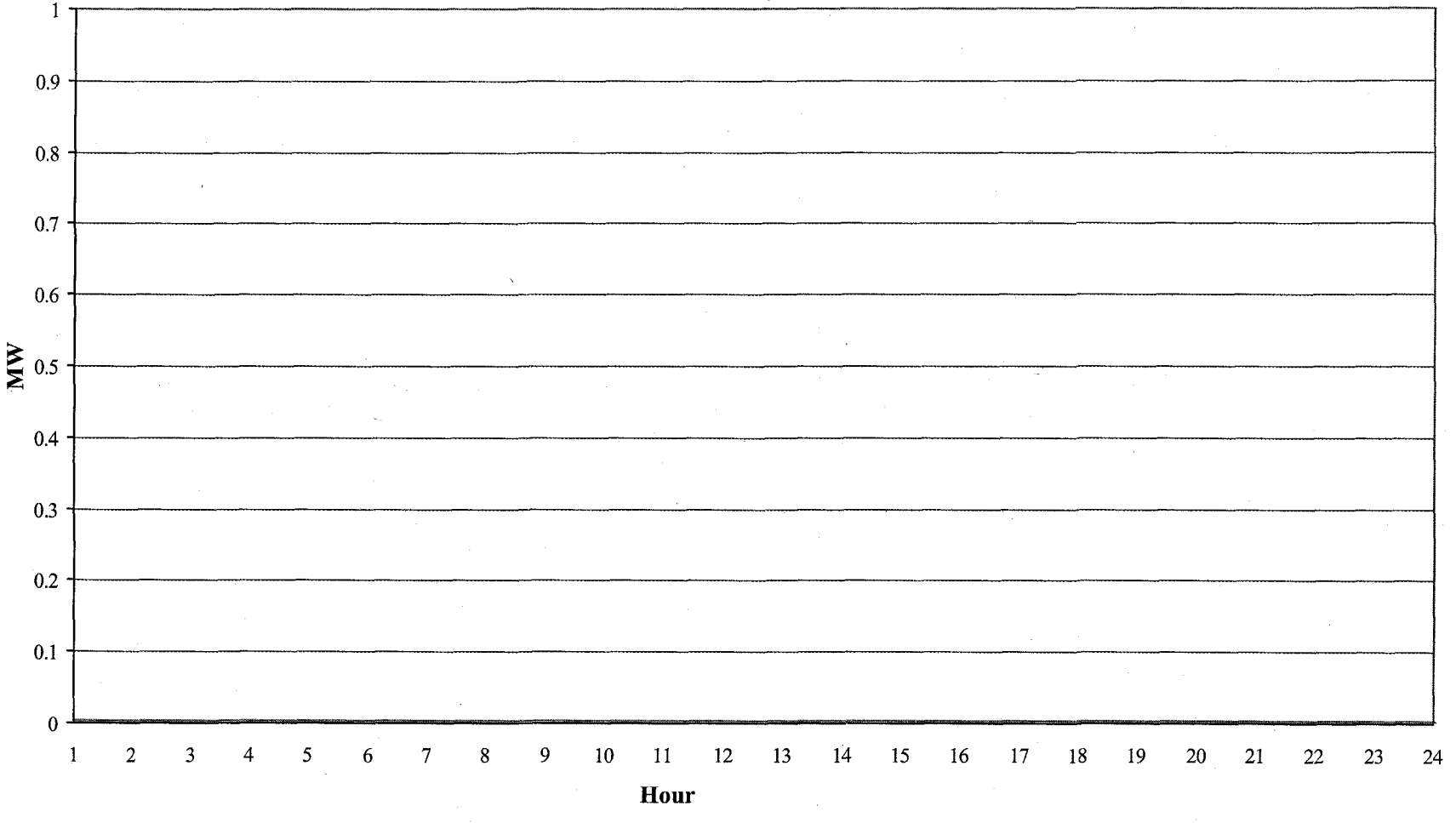
Figure D-8 (page 48 of 53)
Net PX Supply by PowerEX
December 25, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

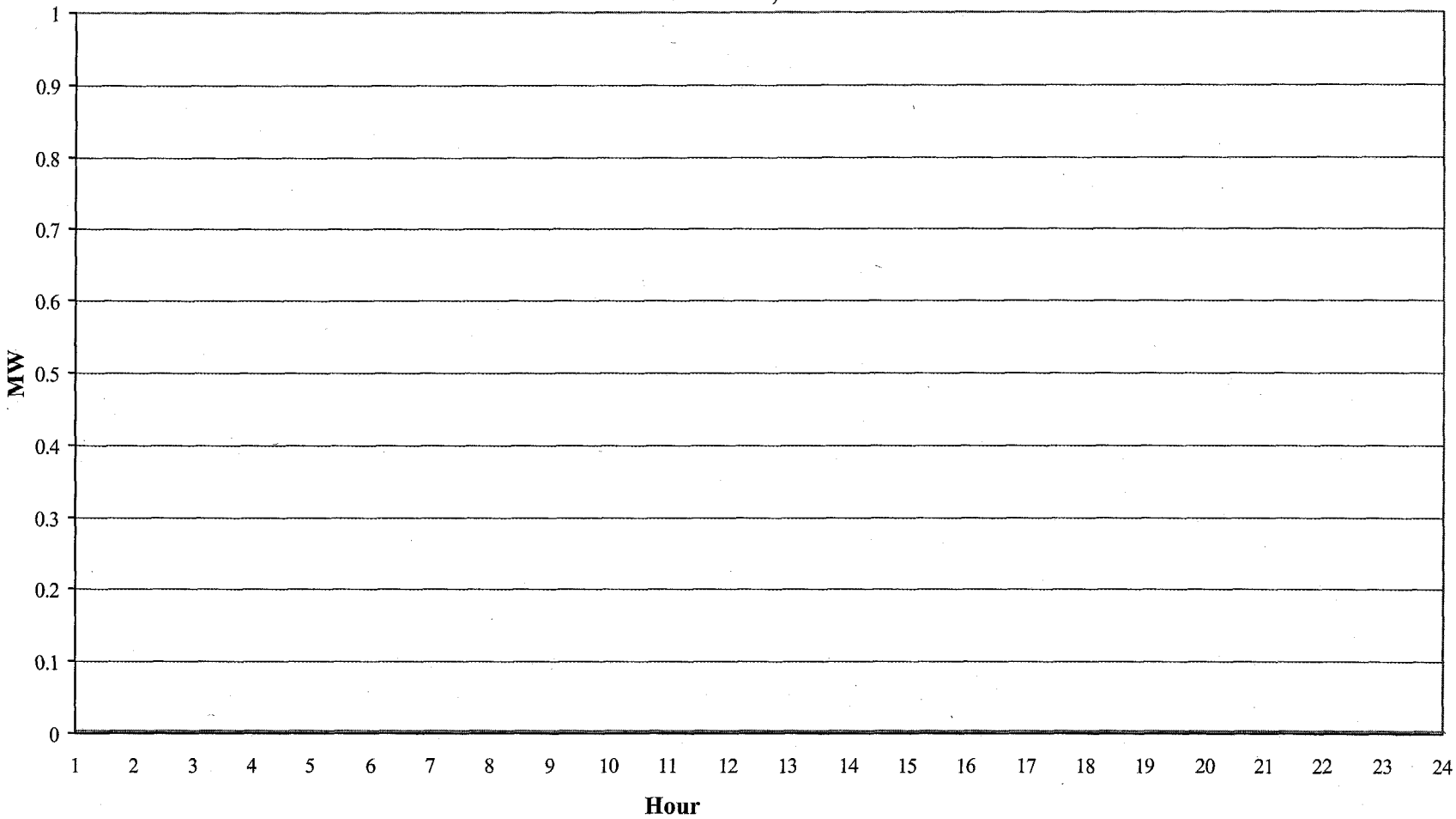
Figure D-8 (page 49 of 53)
Net PX Supply by PowerEX
December 26, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

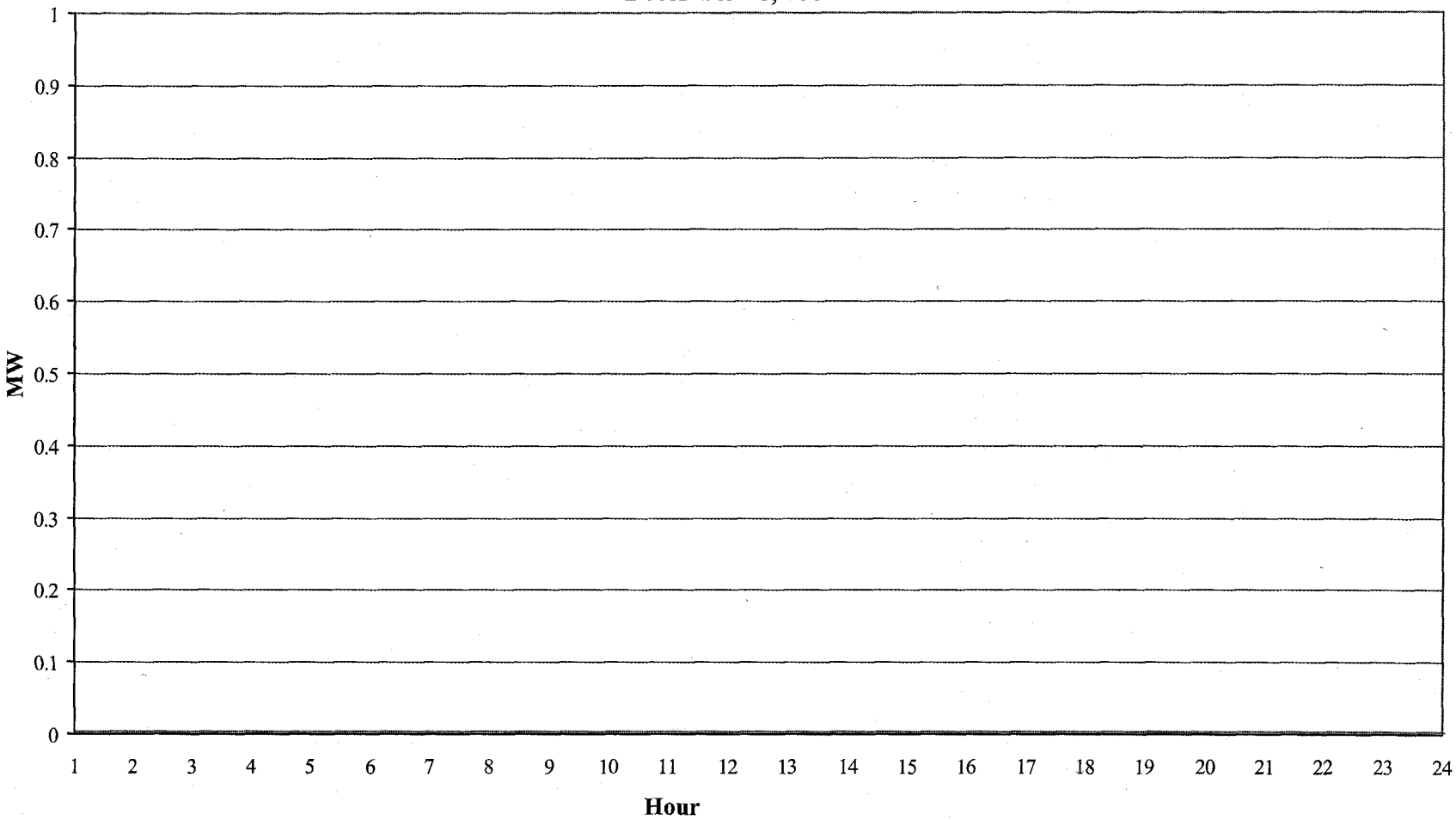
Figure D-8 (page 50 of 53)
Net PX Supply by PowerEX
December 27, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

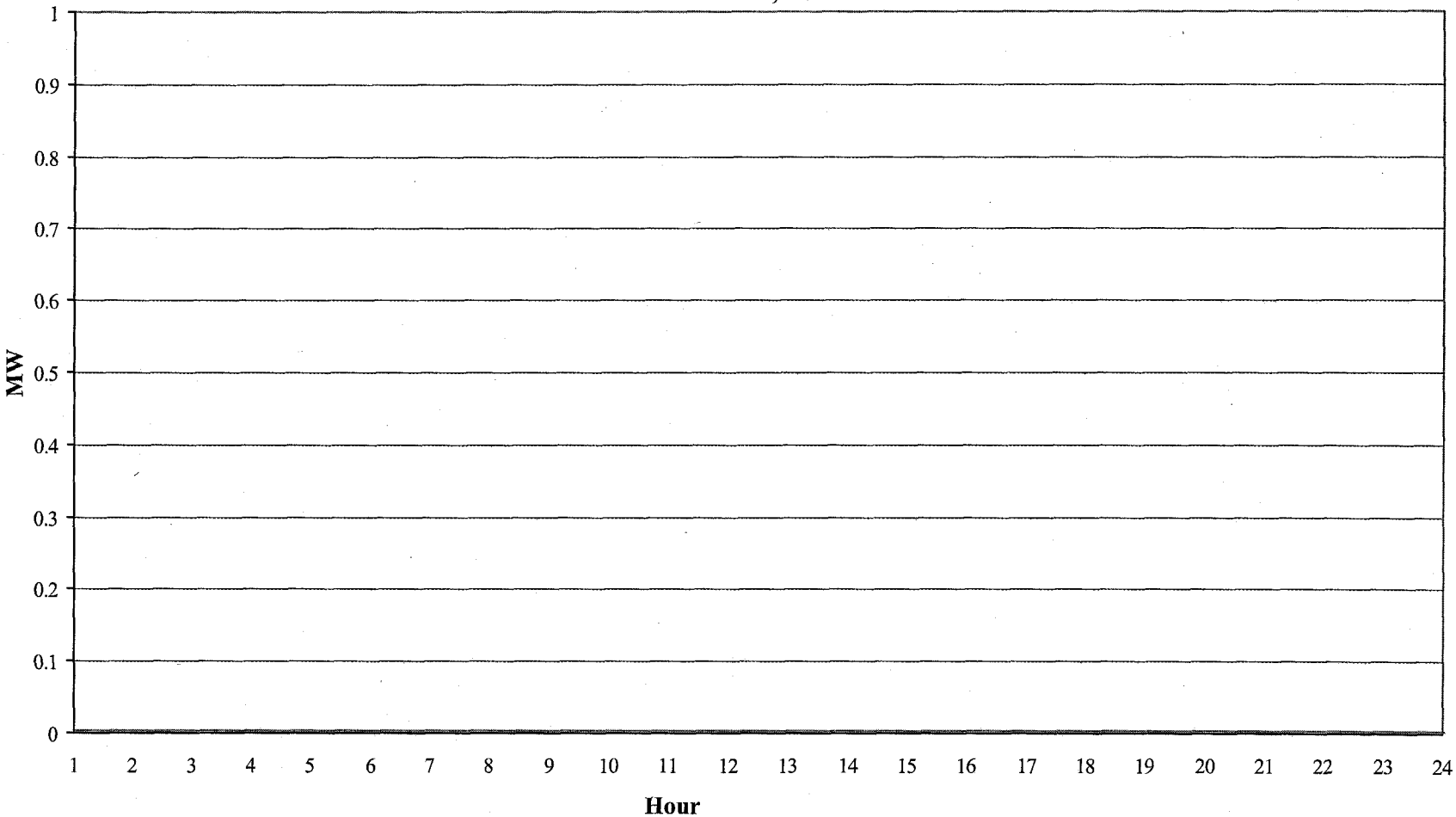
Figure D-8 (page 51 of 53)
Net PX Supply by PowerEX
December 28, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

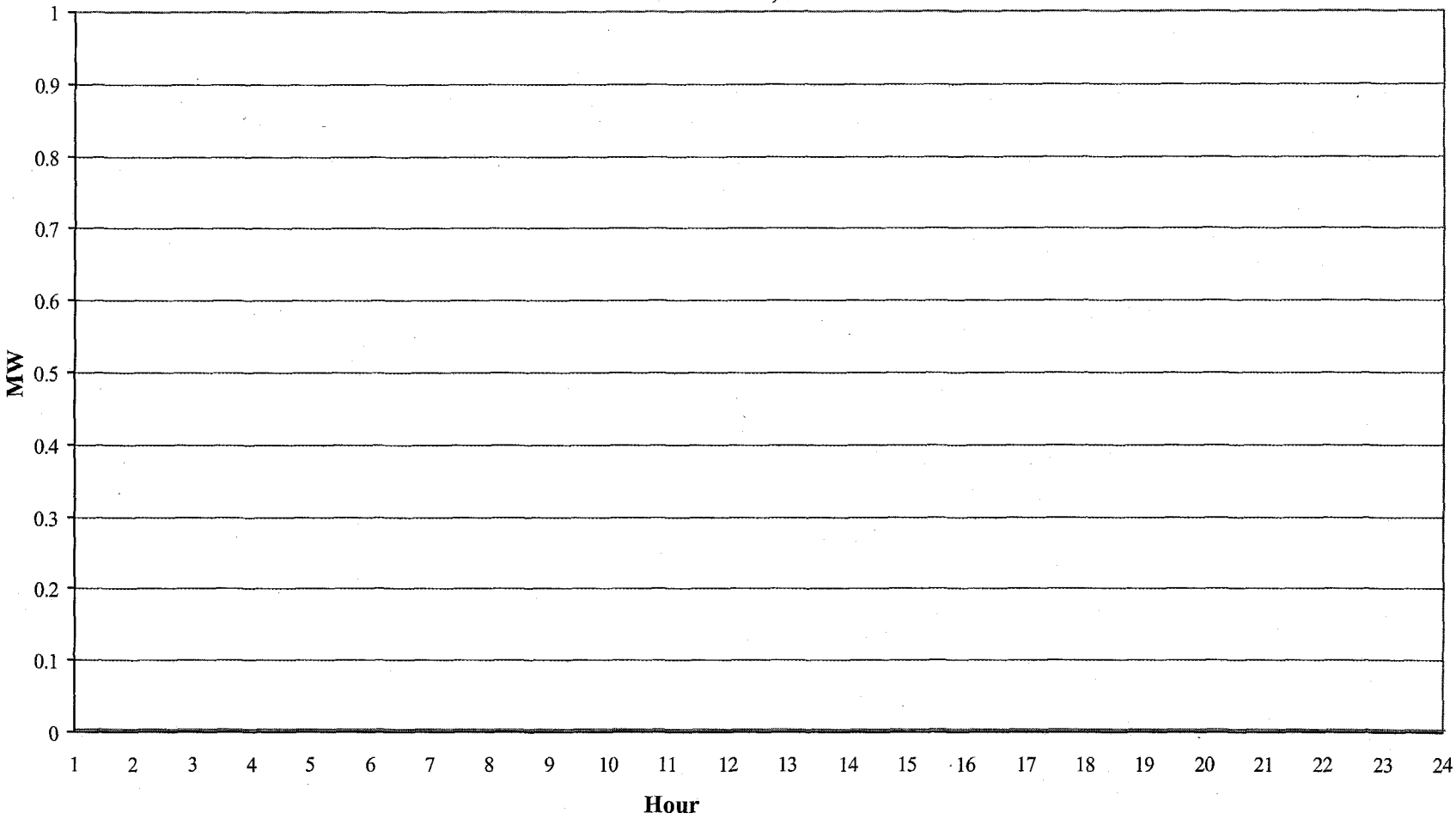
Figure D-8 (page 52 of 53)
Net PX Supply by PowerEX
December 29, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

Contains Protected Material
Not Available to Competitive Duty Personnel

Figure D-8 (page 53 of 53)
Net PX Supply by PowerEX
December 30, 2000



Source: Positive values are sales to the PX. Negative values are purchases from the PX; from CAISO InterSC Trade data.

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Not Available to Competitive Duty Personnel

Table E-1
Total Matching Export-Import Transactions that Are Potential Death Star Trades

Total Circular DA/HA Transactions of Matching Volume In The Same Hour

May 1, 2000 through June 19, 2001

Entity	*MWh*	*Hours*
Enron Power Marketing	11,810	355
Coral Power	11,211	248
Sempra Energy Trading	7,540	148
Morgan Stanley Capital Group	7,419	124
Idaho Power Company	2,689	46
Duke Energy Trading and Mktg.	1,180	40
Puget Sound Energy	1,000	40
Southern Company Energy Mktg.	855	25
San Diego Gas and Electric, Merchant	750	15
Powerex	689	26
Hafslund Energy Trading	325	11
Aquila	296	13
Williams Energy Services	150	6
Modesto Irrigation District	100	5
Portland General Electric	100	2
Transalta Energy Marketing	100	4
Southern California Edison	62	31
FP&L Energy	60	6
Calpine Energy Services	50	2
Total	**46,386**	**1,147**

Sources and Notes:

[1]: Source is California ISO Response to Data Request CAL-ISO-17.
[2]: Transactions that are potentially double-counted (that is, imports that match more than one export in an hour, and exports that match more than one import in an hour) are elimated from the totals for each entity.

Contains Protected Material
Not Available to Competitive Duty Personnel

Table E-2
Matching Export-Import Transactions that Are Potential Death Star Trades

Total Circular DA/HA Transactions of Matching Volume In The Same Hour January 1, 2000 - April 30, 2000			Total Circular DA/HA Transactions of Matching Volume In The Same Hour May 1, 2000 - October 1, 2000			Total Circular DA/HA Transactions of Matching Volume In The Same Hour October 2, 2000 - January 17, 2001			Total Circular DA/HA Transactions of Matching Volume In The Same Hour January 18, 2001 - June 19, 2001		
Entity	*MWh*	*Hours*	*Entity*	*MWh*	*Hours*	*Entity*	*MWh*	*Hours*	*Entity*	*MWh*	*Hours*
Enron Power Marketing	5,795	104	Enron Power Marketing	8,677	278	Coral Power	7,293	179	Morgan Stanley Capital Group	7,419	124
Sempra Energy Trading	2,288	57	Coral Power	3,668	64	Sempra Energy Trading	5,970	120	Idaho Power Company	1,915	20
Coral Power	2,065	39	Sempra Energy Trading	1,570	28	Enron Power Marketing	2,984	73	San Diego Gas and Electric, Merc	750	15
Modesto Irrigation District	360	18	Southern Company Energy Mktg.	805	23	Puget Sound Energy	1,000	40	Powerex	524	9
Aquila	335	7	Duke Energy Trading and Mktg.	575	23	Idaho Power Company	649	21	Coral Power	250	5
Southern California Edison	300	2	Hafslund Energy Trading	325	11	Duke Energy Trading and Mktg.	605	17	Enron Power Marketing	150	4
Williams Energy Services	150	3	Aquila	296	13	Williams Energy Services	150	6	Transalta Energy Marketing	100	4
Arizona Public Service	44	2	Idaho Power Company	125	5	Modesto Irrigation District	100	5	Southern California Edison	62	31
Powerex	25	1	Portland General Electric	100	2	Powerex	79	3	FP&L Energy	60	6
			Powerex	86	14	Southern Company Energy Mktg.	50	2	Calpine Energy Services	50	2
Total for Period	**11,363**	**233**	**Total for Period**	**16,227**	**461**	**Total for Period**	**18,880**	**466**	**Total for Period**	**11,280**	**220**
Total per Month	**2,817**	**58**	**Total per Month**	**3,161**	**90**	**Total per Month**	**5,244**	**129**	**Total per Month**	**2,212**	**43**

Sources and Notes:

[1]: Source is California ISO Response to Data Request CAL-ISO-17.

[2]: Transactions that are potentially double-counted (that is, imports that match more than one export in an hour, and exports that match more than one import in an hour) are elimated from the totals for each entity.

Table E-3
Identified Potential Death Star Trades By Enron and Mirant with Suggestive Interchange ID Codes

SC_ID	OPR DT	OPR HR	tie_point_imp	tie_point_exp	interchg_id_imp	interchg_id_exp	MKT TYPE	fin_mw_imp	fin_mw_exp
EPMI	05MAY00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_STAR	CISO_EPMI_7078	H	44.97	-45
EPMI	05MAY00	15	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_STAR	CISO_EPMI_7078	H	44.97	-45
EPMI	05MAY00	16	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_STAR	CISO_EPMI_7078	H	45	-45
EPMI	14JUN00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	18.97	-19
EPMI	14JUN00	15	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	18.97	-19
EPMI	14JUN00	18	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	19.97	-20
EPMI	14JUN00	19	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	20	-19.97
EPMI	15JUN00	12	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	20	-20
EPMI	15JUN00	13	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	19	-19
EPMI	15JUN00	14	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	19	-19
EPMI	15JUN00	15	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	19	-19
EPMI	15JUN00	16	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	19	-19
EPMI	15JUN00	17	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	19	-19
EPMI	15JUN00	18	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	19	-19
EPMI	15JUN00	19	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	19	-19
EPMI	15JUN00	20	PVERDE_5_DEVERS	MALIN_5_RNDMTN	CISO_EPMI_STAR	EPMI_CISO_DEATH	H	19	-19
EPMI	19JUL00	11	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	19JUL00	12	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.95	-10
EPMI	19JUL00	13	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	19JUL00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	10	-10
EPMI	19JUL00	19	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	10	-10
EPMI	19JUL00	20	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	10	-10
EPMI	19JUL00	21	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	10	-10
EPMI	19JUL00	22	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	20JUL00	11	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	20JUL00	12	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	10	-10
EPMI	20JUL00	13	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	10	-10
EPMI	20JUL00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	20JUL00	15	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	20JUL00	16	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	20JUL00	17	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	20JUL00	18	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	20JUL00	19	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	10	-10
EPMI	20JUL00	21	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	9.97	-10
EPMI	20JUL00	22	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_STAR	H	10	-10
EPMI	21JUL00	12	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_DEATH	CISO_EPMI_STAR	H	10	-10
EPMI	21JUL00	13	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_DEATH	CISO_EPMI_STAR	H	10	-10
EPMI	21JUL00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_DEATH	CISO_EPMI_STAR	H	10	-10
EPMI	21JUL00	15	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_DEATH	CISO_EPMI_STAR	H	10	-10
EPMI	21JUL00	16	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_DEATH	CISO_EPMI_STAR	H	10	-10
EPMI	21JUL00	17	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_DEATH	CISO_EPMI_STAR	H	10	-10
EPMI	21JUL00	18	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_DEATH	CISO_EPMI_STAR	H	10	-10
EPMI	28JUL00	11	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	9.98	-10
EPMI	28JUL00	12	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	10	-9.98
EPMI	28JUL00	13	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	10	-10
EPMI	28JUL00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	10	-10
EPMI	28JUL00	15	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	10	-10
EPMI	28JUL00	16	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	10	-10
EPMI	28JUL00	17	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	9.98	-10
EPMI	28JUL00	18	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	9.98	-10
EPMI	28JUL00	19	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	9.98	-10
EPMI	28JUL00	20	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_DEATH	EPMI_DEATH	H	9.98	-10
EPMI	02AUG00	13	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	9.98	-10
EPMI	02AUG00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	10	-9.98
EPMI	02AUG00	15	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	9.98	-10
EPMI	04AUG00	13	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO	EPMI_STAR	H	9.98	-10
EPMI	04AUG00	13	MEAD_2_WALC	SYLMAR_2_NOB	EPMI_STAR	EPMI_CISO	H	9.99	-10
EPMI	04AUG00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO	EPMI_STAR	H	10	-10
EPMI	04AUG00	14	MEAD_2_WALC	SYLMAR_2_NOB	EPMI_STAR	EPMI_CISO	H	10	-10
EPMI	04AUG00	15	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	10	-10
EPMI	04AUG00	16	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	9.98	-10
EPMI	04AUG00	17	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	9.98	-10
EPMI	04AUG00	18	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	9.98	-10
EPMI	04AUG00	19	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	10	-10
EPMI	04AUG00	20	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	9.99	-10
EPMI	21AUG00	14	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_STAR	EPMI_STAR	H	45	-44.99
EPMI	07SEP00	16	MEAD_2_WALC	MALIN_5_RNDMTN	EPMI_CISO_STAR	EPMI_CISO_STAR	H	44.99	-45
SCEM	28JUL00	13	FCORNR_5_PSUEDO	MALIN_5_RNDMTN	SCEM_LOOPY	SCEM_LOOPY	H	30	-30
SCEM	28JUL00	14	FCORNR_5_PSUEDO	MALIN_5_RNDMTN	SCEM_LOOPY	SCEM_LOOPY	H	30	-30
SCEM	28JUL00	15	FCORNR_5_PSUEDO	MALIN_5_RNDMTN	SCEM_LOOPY	SCEM_LOOPY	H	30	-30
SCEM	28JUL00	16	FCORNR_5_PSUEDO	MALIN_5_RNDMTN	SCEM_LOOPY	SCEM_LOOPY	H	30	-30
SCEM	28JUL00	17	FCORNR_5_PSUEDO	MALIN_5_RNDMTN	SCEM_LOOPY	SCEM_LOOPY	H	20	-20
SCEM	28JUL00	18	FCORNR_5_PSUEDO	MALIN_5_RNDMTN	SCEM_LOOPY	SCEM_LOOPY	H	20	-20

Source: California ISO Response to Data Request CAL-ISO-17.

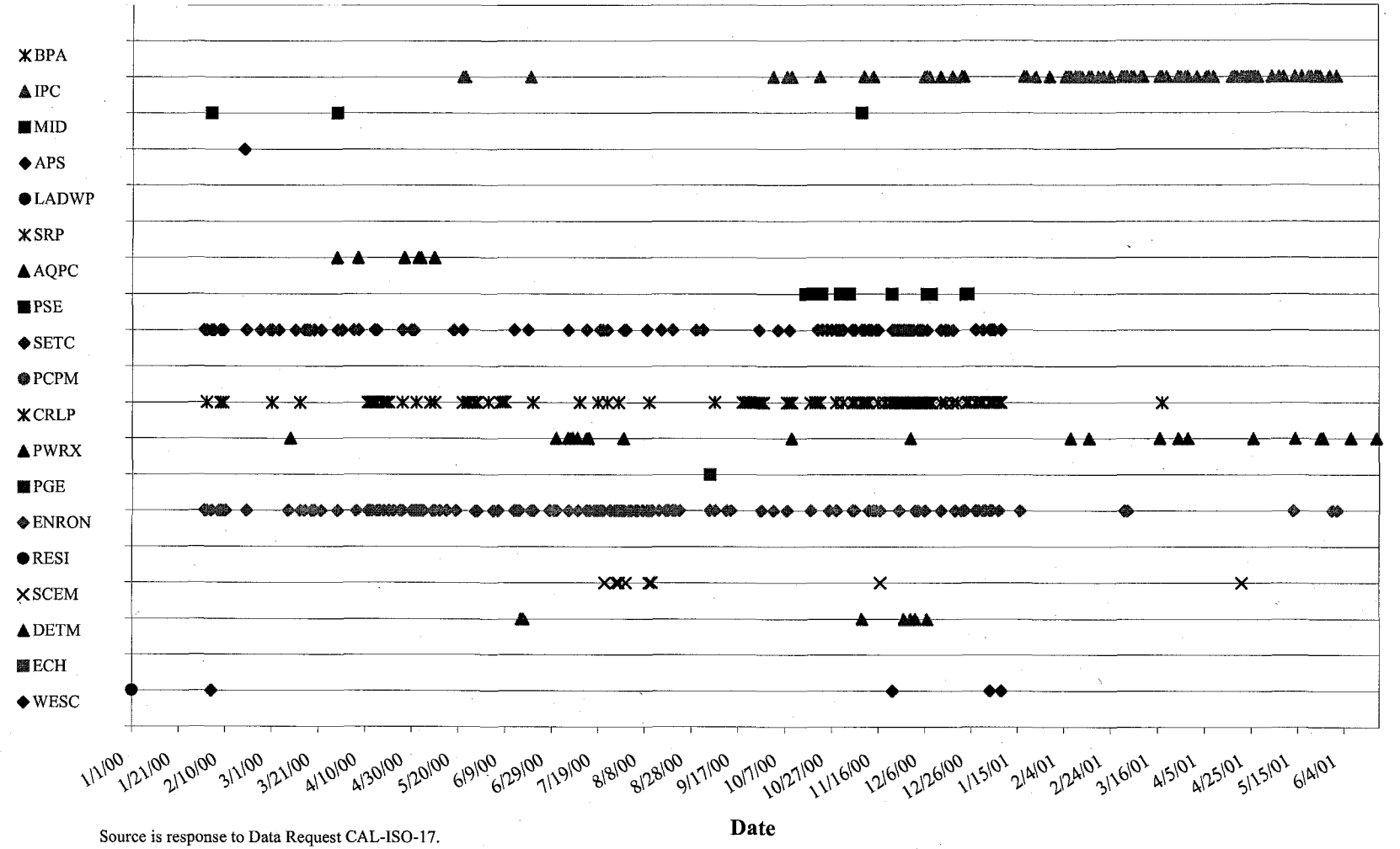
Other Interchange ID Codes Used by Enron in Identified Potential Death Star Trades

interchg_id_imp	*interchg_id_exp*
EPMI_CISO_BLUE	EPMI_CISO_GREEN
EPMI_CISO_GREEN	EPMI_CISO_BLUE
EPMI_CISO_RED	EPMI_CISO_WHITE
EPMI_CISO_WHITE	EPMI_CISO_RED
EPMI_CISO_RED	EPMI_CISO_GREEN
EPMI_CISO_BLUE	EPMI_CISO_RED
EPMI_CISO_BLUE	EPMI_CISO_YELLOW
CISO_RETRIEVER	CISO_GOLDEN
CISO_GOLDEN	CISO_RETRIEVER
EPMI_CISO_TEXAS	CISO_EPMI_FORNEY
EPMI_CISO_DANNY	CISO_EPMI_FORNEY
EPMI_CISO_FORNEY	CISO_EPMI_DANNY
EPMI_CISO_CHINOOK	CISO_EPMI_ATLANTIC
EPMI_CISO_JAMES	CISO_EPMI_DEAN
EPMI_CISO_REDVETTE	CISO_EPMI_DEAN
EPMI_CISO_VELVET	CISO_EPMI_SUEDE
EPMI_CISO_CLEAN	CISO_EPMI_CHEVY
EPMI_CISO_QUEEN	CISO_EPMI_KING
EPMI_CISO_BASS	CISO_EPMI_TROUT
EPMI_CISO_JETTA	EPMI_CISO_VW
EPMI_CISO_HUNGRY	CISO_EPMI_HIPPO
EPMI_CISO_GRAPE	CISO_EPMI_PEACH
EPMI_CISO_TIGER	EPMI_CISO_SHARK
EPMI_CISO_MOON	EPMI_CISO_STAR
EPMI_CISO_ROOT	CISO_EPMI_BEER
EPMI_CISO_BERT	CISO_EPMI_ERNIE
EPMI_CISO_BIG	EPMI_CISO_TUNA
EPMI_FORD	EPMI_DODGE
EPMI_CISO_BIG	EPMI_CISO_BIRD
EPMI_CISO_CURIOUS	CISO_EPMI_GEORGE
EPMI_CISO_BEARS	EPMI_CISO_HUSKIES
EPMI_CISO_HUSKIES	EPMI_CISO_BEARS
EPMI_CISO_HUSKERS	EPMI_CISO_NOLES
EPMI_CISO_BERT	EPMI_CISO_ERNIE
EPMI_CISO_GO	EPMI_CISO_DARE
EPMI_CISO_BLAZERS	CISO_EPMI_BLAZERS
EPMI_CISO_TRAIL	CISO_EPMI_BLAZERS
EPMI_CISO_BROWN	EPMI_CISO_CHEVY
EPMI_CISO_BLUE	CISO_EPMI_BLUE
CISO_EPMI_LINUS	CISO_EPMI_LUCY
CISO_UMBRO	CISO_REEBOK
EPMI_DODGE	EPMI_CHEVY
EPMI_CISO_CHEVY	CISO_EPMI_BROWN
EPMI_CISO_PURPLE	EPMI_CISO_BROWN
EPMI_CISO_BLUE	EPMI_CISO_BLUE
EPMI_CISO_YELLOW	EPMI_CISO_YELLOW
EPMI_CISO_GREEN	EPMI_CISO_GREEN
EPMI_CISO_RED	EPMI_CISO_RED
EPMI_CHEVY	EPMI_CHEVY
EPMI_CISO_KWAK	EPMI_CISO_KWAK
EPMI_CISO_YAMAHA	EPMI_CISO_YAMAHA
CISO_TOYOTA	CISO_TOYOTA
CISO_SCHWINN	CISO_SCHWINN
CISO_TREK	CISO_TREK
CISO_FLAT	CISO_FLAT
EPMI_TRUCK	EPMI_TRUCK
EPMI_CISO_JOSH	EPMI_CISO_JOSH
EPMI_CISO_JACK	EPMI_CISO_JACK
CISO_WH_RIVER	CISO_WH_RIVER
EPMI_CISO_JOHNNY	EPMI_CISO_JOHNNY
EPMI_CISO_DANIEL	EPMI_CISO_DANIEL
EPMI_FISH	EPMI_FISH
EPMI_CISO_HUSKIES	EPMI_CISO_HUSKIES
EPMI_CISO_GOLDEN	EPMI_CISO_GOLDEN
EPMI_TRASH	EPMI_TRASH
EPMI_CISO_HAYES	EPMI_CISO_HAYES
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EPMI_CISO_SCOUT	EPMI_CISO_SCOUT
EPMI_CISO_TAN	EPMI_CISO_TAN
EPMI_CISO_BILL	EPMI_CISO_BILL
EPMI_CISO_BERT	EPMI_CISO_BERT
EPMI_CISO_ERNIE	EPMI_CISO_ERNIE
EPMI_CISO_SHAQ	EPMI_CISO_SHAQ
EPMI_CISO_KOBE	EPMI_CISO_KOBE
EPMI_CISO_WATER	EPMI_CISO_WATER
EPMI_CISO_BEAVERS	EPMI_CISO_BEAVERS

interchg_id_imp	*interchg_id_exp*
EPMI_CISO_CRAIG	EPMI_CISO_CRAIG
EPMI_CISO_DEAN	EPMI_CISO_DEAN
EPMI_CISO_NORTH	EPMI_CISO_NORTH
EPMI_CISO_ORANGE	EPMI_CISO_ORANGE
EPMI_CISO_WHITE	EPMI_CISO_WHITE
EPMI_CISO_B	EPMI_CISO_B
EPMI_CISO_DDD	EPMI_CISO_DDD
CISO_REEBOK	CISO_REEBOK
EPMI_DODGE	EPMI_DODGE
EPMI_FORD	EPMI_FORD
EPMI_JEEP	EPMI_JEEP
EPMI_CISO_DRAKE	EPMI_CISO_DRAKE
EPMI_CISO_ROAD	EPMI_CISO_ROAD
EPMI_CISO_OAK	EPMI_CISO_OAK
EPMI_CISO_RAMS	EPMI_CISO_RAMS
EPMI_CISO_LUCKY	EPMI_CISO_LUCKY
EPMI_CISO_TANA	EPMI_CISO_TANA
EPMI_CISO_DUCKS	EPMI_CISO_DUCKS
EPMI_CISO_ONE	EPMI_CISO_ONE
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EPMI_CISO_TOBY	EPMI_CISO_TOBY
EPMI_CISO_MOUNTAIN	EPMI_CISO_MOUNTAIN
EPMI_CISO_NINJA	EPMI_CISO_NINJA
EPMI_CISO_MOON	EPMI_CISO_MOON
EPMI_CISO_ROSE	EPMI_CISO_ROSE
EPMI_CISO_CLIFF	EPMI_CISO_CLIFF
EPMI_CISO_SILVER	EPMI_CISO_SILVER
EPMI_CISO_ROCK	EPMI_CISO_ROCK
EPMI_CISO_DODGERS	EPMI_CISO_DODGERS
EPMI_CISO_BLUE1	EPMI_CISO_BLUE1
EPMI_CISO_PURPLE	EPMI_CISO_PURPLE
EPMI_CISO_AAA	EPMI_CISO_AAA
EPMI_CISO_YELLOW2	EPMI_CISO_YELLOW2
EPMI_CISO_A	EPMI_CISO_A
EPMI_CISO_BROWN	EPMI_CISO_BROWN
EPMI_CEDAR	EPMI_CEDAR
EPMI_MAXUM	EPMI_MAXUM
EPMI_RED	EPMI_RED
EPMI_BLUE	EPMI_BLUE
EPMI_COLLIE	EPMI_COLLIE
CISO_HONDA	CISO_HONDA
CISO_TIGER	CISO_TIGER
CISO_EPMI_LUCY	CISO_EPMI_LUCY
CISO_UMBRO	CISO_UMBRO
CISO_FORNDOG	CISO_FORNDOG
EPMI_SNAKE	EPMI_SNAKE
EPMI_CISO_TROJANS	EPMI_CISO_TROJANS
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EPMI_CISO_FLY	EPMI_CISO_FLY
EPMI_CISO_CAT	EPMI_CISO_CAT
EPMI_CISO_PRINCE	EPMI_CISO_PRINCE
EPMI_CISO_GO	EPMI_CISO_GO
EPMI_CISO_FOUR	EPMI_CISO_FOUR
EPMI_CISO_MONKEY	EPMI_CISO_MONKEY
EPMI_CISO_DESERT	EPMI_CISO_DESERT
EPMI_CISO_SALSA	EPMI_CISO_SALSA
EPMI_CISO_E	EPMI_CISO_E
EPMI_CISO_X	EPMI_CISO_X
EPMI_CISO_GGG	EPMI_CISO_GGG
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EPMI_CISO_III	EPMI_CISO_III
EPMI_CISO_BBB	EPMI_CISO_BBB
EPMI_CISO_WWW	EPMI_CISO_WWW
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EPMI_CISO_FFF	EPMI_CISO_FFF

Source: California ISO Response to Data Request CAL-ISO-17.

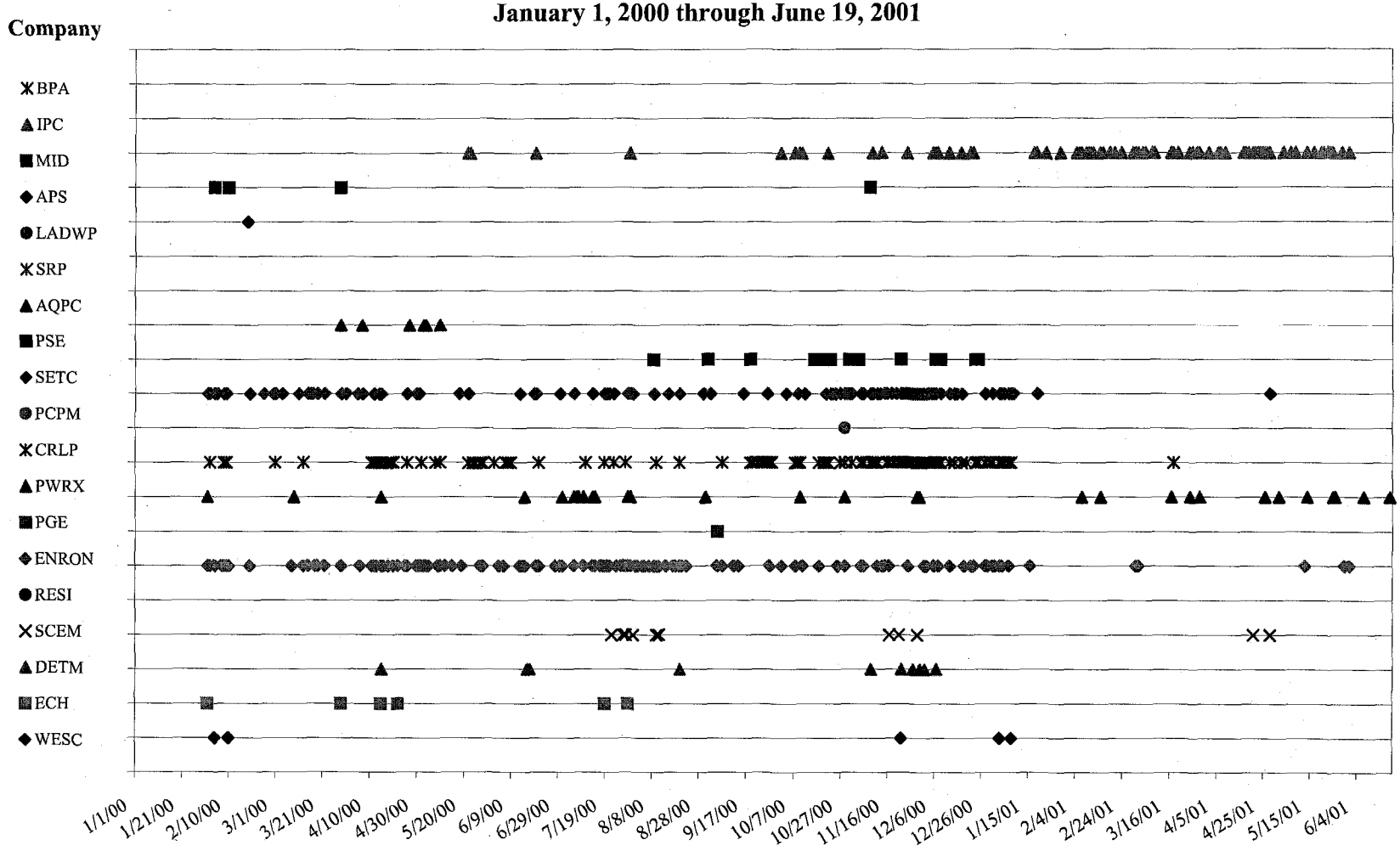
Figure E-1
Deathstar Occurrences
January 1, 2000 through June 19, 2001



Source is response to Data Request CAL-ISO-17.
Workpapers to Hildebrandt's Revised Deathstar Analysis

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Figure E-2
Deathstar and Cut Schedules Occurrences
January 1, 2000 through June 19, 2001



Source is response to data request CAL-ISO-17.
Workpapers to Hildebrandt's Revised Deathstar and Cut Schedules Analysis

Table E-4
Sample of Enron Trade Log Comments for Specific Gaming Transactions

Counterparty	*Deal Date*	*Delivery Point From*	*Delivery Point To*	*Average Price*	*Total Volume*	*Comments*
Avista Corporation - Washington Water Power Division	5/1/00	COB	John Day	1	275	wwp sleeve for Death Star deal
Avista Corporation - Washington Water Power Division	5/3/00	Malin	Portland General System	1	120	WWP buy-resale for Loop
Avista Corporation - Washington Water Power Division	5/4/00	Malin	Portland General System	1	13	WWP buy/resale to PGE, $32 to WWP and $33 to PGE...deathstar
Avista Corporation - Washington Water Power Division	5/4/00	Malin	Portland General System	1	104	RT group doing the Death Star trading strategy this buy resell gives WWP the $1 for the service.
Avista Corporation - Washington Water Power Division	5/9/00	Malin	Portland General System	1	135	Project deathstar. ISO export at Malin to WWP, sold to PGE at system.
Avista Corporation - Washington Water Power Division	5/10/00	Malin	Portland General System	1	90	Death Star buy resell with WWP, we sell to WWP and they sleeve through PGE to give back to us at PGE system.
Avista Corporation - Washington Water Power Division	5/11/00	Malin	Portland General System	1	30	Death Star, giving WWP the $1 for buying Malin and reselling to us at PGE system with the help of PGE.
California Imbalance	1/18/00	SP-15	SP-15	0	50	Glendale fatboy... linked to 281428,281429
California Imbalance	1/22/00	NP-15	NP-15	0	175	Data entered by Jeremy Morris. Fatboy with redding, linked with the deal #283891
California Imbalance	1/24/00	SP-15	SP-15	0	100	Fatboy deal with Glendale (profit sharing with $32 basis).
California Imbalance	1/25/00	NP-15	NP-15	0	150	fATBOT FOR REDDING, LINKED TO DEAL #284708
California Imbalance	3/28/00	SP-15	SP-15	0	100	Fatboy with Valley, deal #'s 313434,313435
California Imbalance	5/2/00	NP-15	NP-15	0	75	Fatboy with Redding HE 20-22, #333097
California Imbalance	5/26/00	SP-15	SP-15	0	150	EPMI real time fatboy with LV Cogen.
California Imbalance	6/13/00	Mead-230KV	Mead-230KV	0	90	deathstar
California Imbalance	6/13/00	Malin	Malin	0	100	deathstar
California Imbalance	6/30/00	NP-15	NP-15	0	100	bought for Deathstar Robinhold
California Imbalance	6/30/00	SP-15	SP-15	0	100	bought for Deathstar Robinhold

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Counterparty	*Deal Date*	*Delivery Point From*	*Delivery Point To*	*Average Price*	*Total Volume*	*Comments*
California Imbalance	7/15/00	NP-15	NP-15	0	300	Redding Fatboy, 20% for EPMI Salisbury
California Imbalance	7/17/00	NP-15	NP-15	0	110	Redding fatboy basis of $60, 80%/20% split, robinhold
California Imbalance	7/23/00	NP-15	NP-15	0	50	Redding Fatboy 30/70 split basis of 65 Robinhold
California Imbalance	7/29/00	NP-15	NP-15	0	125	50%/50% fatboy with Redding Morris/Robinhold
California Imbalance	7/30/00	NP-15	NP-15	0	155	Redding fatboy at 30%/70% Robinhold in RT
California Imbalance	8/5/00	SP-15	SP-15	0	400	RT fatboy with EPE Robinhold
California Imbalance	8/10/00	NP-15	NP-15	0	150	50% split fatboy Jesse set up RT Robinhold
California Power Exchange-Schedule Coordinator	6/18/00	PALO VERDE	PALO VERDE	65	100	Fat boy sale to calpx with EPE. les rawson
California PX Time Removal	6/19/00	PALO VERDE	PALO VERDE	21.43	36	RT cut on sale to PX, bought PX time removal to cover short to PX and sold it to EPE, since we were scheduling their sale to the PX.
City of Glendale	1/17/00	Mead-230KV	Mead-230KV	26.25	40	Intended to be Glendale Fatboy, import cut due to cong, sold bilat to SRP for $24, got the $26.25 value from 50/50 split between $24 and $28.50 basis
City of Glendale	1/24/00	Mead-230KV	Mead-230KV	32	100	Fatboy deal with Glendale (profit sharing with $32 basis).
City of Glendale	1/25/00	Mead-230KV	Mead-230KV	31	50	Data entered by Jeremy Morris. this is a fatboy with glendale.
City of Glendale	3/17/00	Sylmar	Sylmar	30	90	Fatboy with Glendale, basis of$30
City of Glendale	4/3/00	Mead 500KV Node	Mead 500KV Node	35	60	Did Fatboy with Glendale and imported at Mead.
City of Redding	2/3/00	NP-15	NP-15	0	50	FATBOY
City of Redding	3/18/00	NP-15	NP-15	33	350	Fatboy with Redding
City of Redding	6/1/00	NP-15	NP-15	75	75	This is a fat boy deal. les rawson
City of Redding	7/15/00	NP-15	NP-15	70	300	Fatboy with Redding, 20% cut for EPMI Salisbury
City of Redding	7/17/00	NP-15	NP-15	60	110	Redding fatboy basis of $60, 80%/20% split, robinhold
City of Redding	7/23/00	NP-15	NP-15	65	50	Redding Fatboy 30/70 split basis of 65 Robinhold
City of Redding	7/29/00	NP-15	NP-15	102.5	344	50%/50% fatboy with Redding Morris/Robinhold
City of Redding	7/30/00	NP-15	NP-15	70.16	155	Redding fatboy at 30%/70% Robinhold in RT
City of Redding	8/9/00	NP-15	NP-15	65	225	Purchase from Redding, fatboy 70/30(not so fat really)...with a 65 dollar basis. Bill Williams
City of Redding	8/10/00	NP-15	NP-15	0	150	50% split fatboy Jesse set up RT Robinhold
El Paso Electric Company	6/9/00	PALO VERDE	PALO VERDE	35	50	Fat boy deal.

Counterparty	*Deal Date*	*Delivery Point From*	*Delivery Point To*	*Average Price*	*Total Volume*	*Comments*
El Paso Electric Company	6/18/00	PALO VERDE	PALO VERDE	40	100	Fatboy sale to calpx dayof market. les rawson
El Paso Electric Company	6/19/00	PALO VERDE	PALO VERDE	15	3	RT CUT on schedule to PX, booked out the 1mw cut with EPE for $15.
El Paso Electric Company	6/23/00	PALO VERDE	PALO VERDE	43	13	Cut in the hour as we were sucking off the grid Robinhold
El Paso Electric Company	6/23/00	Four Corners-345KV	Four Corners-345KV	53.29	196	HE23 cut at the half due to overselling, we were sucking off the grid Robinhold
EPMI California Pool	1/24/00	Mead-230KV	SP-15	0	100	Fatboy deal with Glendale (profit sharing with $32 basis).
EPMI California Pool	1/25/00	Mead-230KV	SP-15	0	50	Data entered by Jeremy Morris. Fatboy with Glendale, linked to deal# 284795
EPMI California Pool	2/3/00	Mead-230KV	SP-15	0	120	Data entered by Jeremy Morris. Fatboy with Glendale.
EPMI California Pool	3/28/00	Mead-230KV	SP-15	0	140	Fatboy with Valley
EPMI California Pool	5/6/00	NP-15	Malin	0	90	Red Congo, see John Forney. We buy from Redding and sell to PAC in an attempt to relieve cong.
EPMI California Pool	5/9/00	Mead-230KV	Malin	0	120	Project deathstar
EPMI California Pool	5/10/00	Mead-230KV	Malin	0	90	Death Star.
EPMI California Pool	5/26/00	PALO VERDE	SP-15	0	150	EPMI real time fatboy with LV Cogen.
EPMI California Pool	7/1/00	PALO VERDE	Malin	0	40	Deathstar: import in SW and export NW.
EPMI California Pool	7/6/00	PALO VERDE	Malin	0	105	Deathstar PV/Malin/PV
EPMI California Pool	7/15/00	PALO VERDE	COB	0	70	Deathstar play Salisbury
EPMI California Pool	7/17/00	PALO VERDE	COB	0	225	Deathstar RT nonfirm export at Malin, Pac B/R, LA trans to import at PV Robinhold
EPMI California Pool	7/29/00	PALO VERDE	COB	0	100	RT Robinhold Deathsta
EPMI California Pool	8/5/00	PALO VERDE	SP-15	0	400	RT fatboy with EPE Robinhold
EPMI California Pool	8/19/00	Mead-230KV	Malin	0	45	death star
Eugene Water & Electric Board	8/19/00	Malin	Malin	205	60	50/50 fatboy split after $160 basis. Holden
Idaho Power Company, dba IDACORP Energy	6/23/00	Four Corners-345KV	Four Corners-345KV	52.9	196	HE23 cut it in the hour due to sucking off the grid Robinhold
Las Vegas Cogeneration, LP	5/26/00			47	150	EPMI real time fatboy with LV Cogen.
Los Angeles Dept. of Water & Power	1/18/00	Mead-230KV	Mead-230KV	25	13	GLENDALE FATBOY SELL OFF B/C OF CONGESTION

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Counterparty	*Deal Date*	*Delivery Point From*	*Delivery Point To*	*Average Price*	*Total Volume*	*Comments*
Los Angeles Dept. of Water & Power	7/17/00	COB	PALO VERDE	0	0	Deathstar RT nonfirm export at Malin, Pac B/R, LA trans to import at PV Robinhold zeroed this to use 292672 instead.
Nevada Power Company	5/26/00		Mead-230KV	4.1	150	EPMI real time fatboy with LV Cogen.
Northern California Power Agency	11/27/00	NP-15	NP-15	15162	1	Transmission costs due to NCPA($19mw/day) for June, July & August. ds June= 14 days @ $5,586 July= 5 days @ $1,995 August= 19 days @ $7,581
Northern California Power Agency	11/27/00	NP-15	NP-15	161054.16	1	Profit sharing revenue due to NCPA for NP to ZP transmission. ds June= $14,239.81 July= $25,022.41 August= $121,791.93
Northern California Power Agency	4/10/01		NP-15	25	10	Fee of $25 to NCPA for buy/resale across Path 15. Bill Williams 04/10/01
Northern California Power Agency	4/12/01		NP-15	40	120	b/r with NCPA across path 15-Bill Williams
Pacificorp	7/15/00	COB	COB	5	70	Deathstar play Salisbury
Pacificorp	7/17/00	COB	COB	5	225	Deathstar RT nonfirm export at Malin, Pac B/R, LA trans to import at PV Robinhold
Pacificorp	7/29/00	COB	COB	5	100	RT Robinhold Deathstar
Pacificorp	8/19/00	Malin	COB	-5	45	death star
Public Service Company Of New Mexico	6/23/00	PALO VERDE	PALO VERDE	43	13	cut from 25 at the half as we were sucking from the grid. Robinhold
Public Service Company Of New Mexico	7/20/00	Four Corners-345KV	Four Corners-345KV	0	800	This reflects parking from PNM. We have already paid for this service, so no price will appear on this ticket. jforney
Public Service Company Of New Mexico	9/5/00	Four Corners-345KV	Four Corners-345KV	0	800	Issued to reflect Parking length with PNM. Parking is prepaid, thus no cost reflected in this deal. JForney
Public Service Company Of New Mexico	9/15/00	PALO VERDE	PALO VERDE	0	1600	Parking with PNM. This has already been paid for, so no costs is reflected here. JForney

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Counterparty	*Deal Date*	*Delivery Point From*	*Delivery Point To*	*Average Price*	*Total Volume*	*Comments*
Salt River Project Agricultural Improvement and Power District	2/17/00	Mead-230KV	Mead-230KV	33	25	Data entered by Jeremy Morris. This deal due to a schedule cut. We bought 50 mw's on the half intergrated to 25.
Salt River Project Agricultural Improvement and Power District	5/26/00	Mead-230KV	PALO VERDE	1.55	150	EPMI real time fatboy with LV Cogen.
Seattle City Light	3/23/00	BC Border	BC Border	35	150	Puchased to send to Enron Canada but schedule was cut by BC Hydro for HE 13. Energy remarketed to Puget. ECC transmission was reinstated and the power was purchased by BPA. Losses from original purchase were included in price to ECC for HE13. HE14 fine
Valley Electric Association, Inc.	2/17/00	Mead-230KV	Mead-230KV	29.07	31	Fat Boy with Valley Electric at Mead230.
Valley Electric Association, Inc.	3/14/00	Mead-230KV	Mead-230KV	23.73	40	RT deal FAT BOY with Valley, per Jeff Miller it is inputed as Index Forward deal. with a $.25 offset.
Valley Electric Association, Inc.	3/15/00	Mead-230KV	Mead-230KV	14.42	50	RT deal ramping up Valley for FAT BOY profit sharing deal, inputed as index forward from Jeff Miller's instruction with a $.25 offset.
Valley Electric Association, Inc.	3/28/00	Mead-230KV	Mead-230KV	29.2	140	This is a fatboy with Valley
Valley Electric Association, Inc.	4/3/00	Mead-230KV	Mead-230KV	50.39	83	Fatboy with Valley taken in at Mead.

Source:
Excerpts from Exh. No. CA-74.

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Table F-1

Total Schedules Cut After Receiving Counterflow Payments

May 1, 2000 through June 19, 2001

Entity	*MWh*	*Hours*	*% of Total MWh*
Dynegy Power Marketing	4,823	12	21%
Morgan Stanley Capital Group	4,100	44	18%
Sempra Energy Trading	3,113	59	14%
Powerex	2,933	41	13%
San Diego Gas and Electric Company	1,331	19	6%
Enron Power Marketing	1,314	41	6%
Coral Power	1,018	35	5%
Puget Sound Energy	612	12	3%
Idaho Power Company	602	19	3%
Pacificorp	453	4	2%
American Electric Power	450	9	2%
Duke Energy Trading and Mktg.	366	19	2%
Southern California Edison	276	8	1%
Southern Company Energy Mktg.	178	7	1%
Transalta Energy Marketing	170	4	1%
Portland General Electric	127	3	1%
Sierra Pacific Power	125	5	1%
City of Glendale	76	4	0%
Pacific Gas and Electric Company	16	2	0%
Constellation Power Source	4	2	0%
Total	**22,486**	**357**	**100%**

Sources and Notes:

Sources are files Zeroratedpaths_00_02.xls and Cut_Schedules_fina_allscsl.xls submitted as part of California ISO Responses to Data Request CAL-ISO-17.

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Table F-2

Total Schedules Cut After Receiving Counterflow Payments

January 1, 2000 - April 30, 2000			May 1, 2000 - October 1, 2000			October 2, 2000 - January 17, 2001			January 18, 2001 - June 19, 2001		
Entity	*MW*	*Hours*	*Entity*	*MWh*	*Hours*	*Entity*	*MWh*	*Hours*	*Entity*	*MWh*	*Hours*
American Electric Power	2,432	18	Dynegy Power Marketing	4,823	12	San Diego Gas and Electric	1,279	17	Morgan Stanley Capital Group	4,100	44
San Diego Gas and Electric	1,650	18	Powerex	2,660	33	Sempra Energy Trading	1,076	34	Idaho Power Company	400	8
Sempra Energy Trading	698	11	Sempra Energy Trading	1,944	22	Coral Power	544	27	Powerex	119	3
Arizona Public Service	394	5	Enron Power Marketing	886	23	Enron Power Marketing	428	18	Transalta Energy Marketing	95	2
Pacificorp	275	3	Puget Sound Energy	600	11	Duke Energy Trading and Mktg.	205	7	Sempra Energy Trading	93	3
Enron Power Marketing	174	7	Coral Power	474	8	Powerex	154	5	San Diego Gas and Electric	52	2
Dynegy Power Marketing	71	4	American Electric Power	450	9	Southern Company Energy Mktg.	150	5	Southern Company Energy Mktg.	28	2
Coral Power	51	2	Pacificorp	449	3	Sierra Pacific Power	125	5			
Modesto Irrigation District	50	1	Southern California Edison	276	8	Idaho Power Company	79	2			
Public Service Company of New Mexico	50	1	Duke Energy Trading and Mktg.	161	12	City of Glendale	76	4			
Duke Energy Trading and Mktg.	34	2	Idaho Power Company	123	9	Portland General Electric	69	2			
Williams Energy Services	21	1	Portland General Electric	58	1	Transalta Energy Marketing	50	1			
Powerex	20	2	Transalta Energy Marketing	25	1	Puget Sound Energy	12	1			
PG&E Energy Services	17	1	Pacific Gas and Electric Company	16	2	Pacificorp	4	1			
			Constellation Power Source	4	2						
Total	**5,938**	**76**	**Total**	**12,949**	**156**	**Total**	**4,251**	**129**	**Total**	**5,287**	**72**
Monthly Average	**1,472**	**19**	**Monthly Average**	**2,522**	**30**	**Monthly Average**	**1,181**	**36**	**Monthly Average**	**1,037**	**14**

Sources and Notes:
Sources are files Zeroratedpaths_00_02.xls and Cut_Schedules_fina_allscsl.xls submitted as part of California ISO Responses to Data Request CAL-ISO-17.

Table F-3

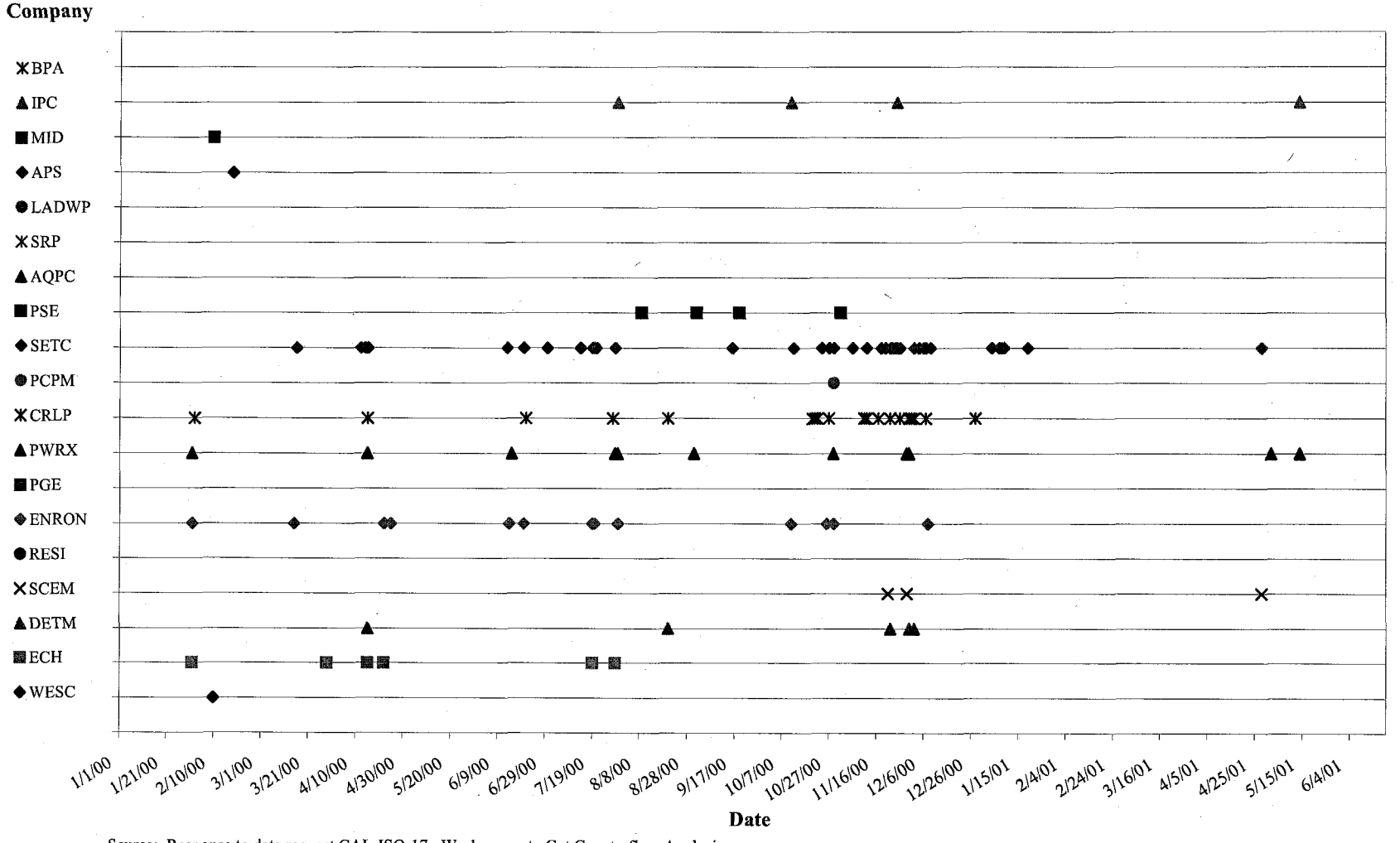
Cut Schedule Transactions with ISO Operator Log Entries

Entity	*Date*	*Hour*	*Tie-Point*	*ISO Operator Log Entry*
Coral Power	07/28/2000	14	SYLMAR_2_NOB	#605136 CRLP cut, no source
Coral Power	10/20/2000	3	SYLMAR_2_NOB	#621347 CRLP cut schedule, no transmission
Coral Power	10/20/2000	4	SYLMAR_2_NOB	#621347 CRLP cut schedule, no transmission
Coral Power	10/20/2000	5	SYLMAR_2_NOB	#621347 CRLP cut schedule, no transmission
Coral Power	11/11/2000	24	SYLMAR_2_NOB	#625419 CRLP cut, no source
Coral Power	11/26/2000	17	MEAD_2_WALC	#628800 CRLP cut schedule
Coral Power	11/30/2000	24	PVERDE_5_DEVERS	#630276 CRLP cut, no source
Coral Power	12/01/2000	12	PVERDE_5_DEVERS	#630384 CRLP cut schedules
Coral Power	12/01/2000	13	PVERDE_5_DEVERS	#630384 CRLP cut schedules
Coral Power	12/28/2000	18	MEAD_2_WALC	#638001 CRLP cut, no sources, sinks
Coral Power	12/28/2000	18	MEAD_2_WALC	#638001 CRLP cut, no sources, sinks
Coral Power	12/28/2000	18	MEAD_2_WALC	#638001 CRLP cut, no sources, sinks
Duke Energy Trading and Mktg.	08/20/2000	15	MALIN_5_RNDMTN	#609857 DETM cut, could not secure supplier
Duke Energy Trading and Mktg.	08/20/2000	16	MALIN_5_RNDMTN	#609857 DETM cut, could not secure supplier
Duke Energy Trading and Mktg.	11/30/2000	24	FCORNR_5_PSUEDO	#630236 DETM cut, no source
Enron Power Marketing	04/25/2000	12	SYLMAR_2_NOB	#578474 EPMI cut, no transmission
Enron Power Marketing	04/25/2000	12	SYLMAR_2_NOB	#578424 EPMI cut, no source; #578474 EPMI cut, no transmission (two logs)
Enron Power Marketing	04/25/2000	15	SYLMAR_2_NOB	#578474 EPMI cut, no transmission
Enron Power Marketing	04/25/2000	16	SYLMAR_2_NOB	#578474 EPMI cut, no transmission
Enron Power Marketing	07/20/2000	13	SYLMAR_2_NOB	#603658, #603671 EPMI cut schedule, no sink
Enron Power Marketing	07/20/2000	14	SYLMAR_2_NOB	#603672 EPMI cut schedule, no sink
Enron Power Marketing	07/20/2000	15	SYLMAR_2_NOB	#603676 EPMI cut schedule, no sink
Enron Power Marketing	07/20/2000	16	SYLMAR_2_NOB	#603678 EPMI cut schedule, no sink
Enron Power Marketing	10/26/2000	1	FCORNR_5_PSUEDO	#622449 No sources, sinks
Enron Power Marketing	10/26/2000	1	PVERDE_5_DEVERS	#622449 No sources, sinks
Enron Power Marketing	10/26/2000	1	PVERDE_5_DEVERS	#622449 No sources, sinks
Morgan Stanley Capital Group	04/13/2001	8	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	9	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	10	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	11	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	12	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	13	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	14	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	15	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	16	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	17	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	18	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/13/2001	19	MALIN_5_RNDMTN	#633814 APX cut schedule
Morgan Stanley Capital Group	04/14/2001	8	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	9	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	10	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	11	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	12	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	13	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	14	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	15	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	16	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	17	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	18	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	19	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	20	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	21	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Morgan Stanley Capital Group	04/14/2001	22	MALIN_5_RNDMTN	#664180 APX reduced schedule to 0
Portland General Electric	08/14/2000	4	SYLMAR_2_NOB	#608464 PGE did not run schedule
Powerex	06/15/2000	3	SUMITM_1_SPP	#597170 Transmission constraint, cut.
San Diego Gas and Electric	11/16/2000	14	MALIN_5_RNDMTN	#626587 SDGE cut schedule, no transmission
San Diego Gas and Electric	11/16/2000	15	MALIN_5_RNDMTN	#626587 SDGE cut schedule, no transmission
San Diego Gas and Electric	11/16/2000	16	MALIN_5_RNDMTN	#626587 SDGE cut schedule, no transmission
Sempra Energy Trading	04/12/2000	14	SYLMAR_2_NOB	#574644 SETC failed to obtain transmission, sink
Sempra Energy Trading	04/12/2000	15	SYLMAR_2_NOB	#574647 SETC failed to obtain transmission, sink
Sempra Energy Trading	04/14/2000	16	MEAD_2_WALC	#575258 SETC reduced to 0, no transmission
Sempra Energy Trading	04/14/2000	17	MEAD_2_WALC	#575258 SETC reduced to 0, no transmission
Sempra Energy Trading	07/20/2000	16	SYLMAR_2_NOB	#603639 SETC cut schedule
Sempra Energy Trading	07/20/2000	17	SYLMAR_2_NOB	#603695 SETC cut schedule
Sempra Energy Trading	11/06/2000	24	FCORNR_5_PSUEDO	#624522 SETC cut, no transmission in APS
Sempra Energy Trading	11/12/2000	4	SYLMAR_2_NOB	#625479 SETC could not find sufficient generation
Sempra Energy Trading	11/12/2000	5	SYLMAR_2_NOB	#625479 SETC could not find sufficient generation
Sempra Energy Trading	11/12/2000	6	SYLMAR_2_NOB	#625479 SETC could not find sufficient generation
Sempra Energy Trading	11/12/2000	7	SYLMAR_2_NOB	#625479 SETC could not find sufficient generation
Sempra Energy Trading	11/24/2000	18	PVERDE_5_DEVERS	#628423 SETC cut, no transmission
Sempra Energy Trading	01/04/2001	23	PVERDE_5_DEVERS	#639357 SETC cut, no sink
Southern Company Energy Mktg.	11/21/2000	15	MALIN_5_RNDMTN	#627951 SCEM cut schedule

Sources and Notes:
Sources are files Zeroratedpaths_00_02.xls and Cut_Schedules_fina_allscsl.xls submitted as part of California ISO Responses to Data Request CAL-ISO-17
Although APX reduced the Morgan Stanley Capital Group (MSCG) schedules, the APX would have been scheduling on behalf of MSCG. It is therefore likely that the cuts were initiated by MSCG.

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Figure F-1
Cut Schedules Occurrences
January 1, 2000 through June 19, 2001



Source: Response to data request CAL-ISO-17: Workpapers to Cut Counterflow Analysis

Table G-1
Ancillary Services Buyback Summary (Within ISO Generators - Peak Hours)

Panel A: 1/1/00 - 4/30/00

Scheduling Coordinator	*When Buyback Occurs*					*When No Buyback Occurs*			*DA AS Sales When Buyback Occurs Less HA AS Sales When No Buyback Occurs (MW)*	*Number of Hours with No AS Sales*
	Number of Hours	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*Average Buyback MW*	*Average Buyback % of DA Sales*	*Number of Hours*	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*		
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*
Dynegy Power Marketing, Inc.	711	193.9	187.6	6.3	3.3%	902	218.5	254.7	-60.8	19
California Power Exchange	109	666.9	631.2	35.6	5.3%	1,523	546.1	635.6	31.3	0
City of Pasadena	46	22.7	7.0	15.7	69.1%	975	25.0	29.6	-6.9	611
Williams Energy Services Corporation	67	253.0	181.3	71.7	28.3%	947	130.9	165.5	87.5	618
Reliant Energy Services, Inc.	44	117.1	52.9	64.2	54.8%	469	8.3	16.1	101.0	1,119
California Department of Water Resources	26	397.5	329.2	68.3	17.2%	1,351	188.1	243.5	154.0	255
Automated Power Exchange, Inc	16	19.6	3.6	16.0	81.7%	1,539	39.8	39.8	-20.3	77
Pacific Gas and Electric Company	11	43.7	42.0	1.7	4.0%	1,620	29.4	65.9	-22.2	1
Duke Energy Trading and Marketing, L.L.C.	7	40.4	21.0	19.4	48.1%	326	5.6	47.6	-7.2	1,299
Totals (Weighted by Hours) [11]	**1,037**	**236.4**	**218.1**	**18.2**	**7.7%**	**9,652**	**160.2**	**197.2**	**-25.5**	**3,999**

Panel B: 5/2/00 - 10/1/00

Scheduling Coordinator	*When Buyback Occurs*					*When No Buyback Occurs*			*DA AS Sales When Buyback Occurs Less HA AS Sales When No Buyback Occurs (MW)*	*Number of Hours with No AS Sales*
	Number of Hours	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*Average Buyback MW*	*Average Buyback % of DA Sales*	*Number of Hours*	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*		
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*
Dynegy Power Marketing, Inc.	247	252.7	235.4	17.3	6.8%	1,641.0	177.8	257.7	-5.0	176
Pacific Gas and Electric Company	214	14.9	3.2	11.7	78.7%	1,595.0	46.3	78.8	-63.9	255
California Power Exchange	79	775.4	712.8	62.6	8.1%	1,985.0	623.0	733.9	41.5	0
City of Pasadena	77	72.0	45.0	26.9	37.4%	1,811.0	48.6	66.3	5.7	176
Williams Energy Services Corporation	71	226.1	133.2	92.8	41.1%	924.0	56.8	112.9	113.2	1,069
California Department of Water Resources	47	237.1	173.8	63.3	26.7%	1,749.0	167.3	245.7	-8.6	268
Reliant Energy Services, Inc.	54	220.8	187.1	33.7	15.2%	497.0	200.1	276.8	-56.0	1,513
Duke Energy Trading and Marketing, L.L.C.	17	70.9	48.8	22.1	31.2%	600.0	62.6	122.1	-51.1	1,447
ENRON Power Marketing Inc	17	13.5	4.7	8.9	65.6%	526.0	14.2	15.2	-1.6	1,521
Northern California Power Agency	15	54.3	33.3	21.0	38.6%	1,177.0	47.8	48.2	6.1	872
Mirant	8	593.9	547.7	46.3	7.8%	601.0	111.2	407.9	186.1	1,455
Coral Power, LLC	1	10.0	0.0	10.0	100.0%	392.0	8.2	8.8	1.2	1,671
Totals (Weighted by Hours) [11]	**847**	**210.8**	**179.6**	**31.2**	**14.8%**	**13,498**	**170.8**	**235.9**	**-7.0**	**10,423**

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Table G-1
Ancillary Services Buyback Summary (Within ISO Generators - Peak Hours)

Panel C: 10/2/00 - 1/17/01

Scheduling Coordinator	*When Buyback Occurs*					*When No Buyback Occurs*			*DA AS Sales When Buyback Occurs Less HA AS Sales When No Buyback Occurs (MW)*	*Number of Hours with No AS Sales*
	Number of Hours	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*Average Buyback MW*	*Average Buyback % of DA Sales*	*Number of Hours*	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*		
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*
Dynegy Power Marketing, Inc.	136	281.5	247.8	33.7	12.0%	1,168.0	214.9	305.7	-24.2	136
Mirant	97	306.6	203.2	103.4	33.7%	615.0	106.7	187.2	119.4	728
Duke Energy Trading and Marketing, L.L.C.	65	389.9	327.2	62.7	16.1%	893.0	263.0	342.3	47.6	482
Reliant Energy Services, Inc.	48	214.5	170.3	44.1	20.6%	769.0	98.3	238.0	-23.5	623
Williams Energy Services Corporation	42	247.6	163.1	84.5	34.1%	860.0	184.7	274.3	-26.7	538
California Power Exchange	42	633.2	572.3	60.9	9.6%	1,398.0	494.9	566.2	66.9	0
California Department of Water Resources	29	271.2	118.3	152.9	56.4%	908.0	162.4	200.3	70.9	503
City of Pasadena	27	93.5	84.0	9.5	10.1%	1,376.0	49.5	66.5	27.0	37
Automated Power Exchange, Inc	16	16.0	0.0	16.0	100.0%	1,403.0	20.3	20.4	-4.4	21
ENRON Power Marketing Inc	9	15.0	0.0	15.0	100.0%	120.0	17.4	18.1	-3.1	1,311
Pacific Gas and Electric Company	3	55.4	53.5	1.9	3.4%	1,437.0	74.9	117.3	-61.9	0
Totals (Weighted by Hours) [11]	**514**	**294.9**	**232.7**	**62.3**	**21.1%**	**10,947**	**167.3**	**224.8**	**28.1**	**4,379**

Panel D: 1/18/01 - 6/19/01

Scheduling Coordinator	*When Buyback Occurs*					*When No Buyback Occurs*			*DA AS Sales When Buyback Occurs Less HA AS Sales When No Buyback Occurs (MW)*	*Number of Hours with No AS Sales*
	Number of Hours	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*Average Buyback MW*	*Average Buyback % of DA Sales*	*Number of Hours*	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*		
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*
Southern California Edison Company	219	510.7	453.6	57.1	11.2%	1,495.0	460.2	474.4	36.3	366
City of Pasadena	186	68.1	55.5	12.7	18.6%	1,879.0	48.9	54.3	13.8	15
Dynegy Power Marketing, Inc.	238	305.2	289.7	15.6	5.1%	894.0	290.9	380.7	-75.5	948
Williams Energy Services Corporation	204	139.2	103.7	35.4	25.5%	1,455.0	129.6	180.5	-41.3	421
Pacific Gas and Electric Company	96	1,431.8	1,250.0	181.7	12.7%	1,984.0	1,113.0	1,167.7	264.1	0
Reliant Energy Services, Inc.	20	292.7	238.9	53.8	18.4%	442.0	34.3	222.6	70.1	1,618
California Department of Water Resources	22	298.5	164.2	134.3	45.0%	910.0	173.6	239.2	59.4	1,148
Duke Energy Trading and Marketing, L.L.C.	9	169.2	152.6	16.7	9.8%	198.0	63.5	144.0	25.2	1,873
California Power Exchange 3	4	1,811.8	1,508.3	303.6	16.8%	364.0	1,515.3	1,530.8	281.1	1,712
Automated Power Exchange, Inc	7	16.0	0.0	16.0	100.0%	1,082.0	11.5	14.9	1.1	991
City of Anaheim	6	44.3	0.0	44.3	100.0%	281.0	42.9	44.1	0.2	1,793
Totals (Weighted by Hours) [11]	**1,011**	**380.4**	**331.9**	**48.5**	**12.7%**	**10,984**	**382.2**	**424.4**	**13.4**	**10,885**

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Table G-1
Ancillary Services Buyback Summary (Within ISO Generators - Peak Hours)

Notes and Sources:
Calculations derived from generation data produced in response to CAL-ISO 4.
Ancillary services defined as spinning, non-spinning, and replacement reserves.
[1]: Number of peak hours in period where total day-ahead ancillary service sales exceed total hour-ahead ancillary service sales for scheduling coordinator identifier.
[2]: Average day-ahead ancillary services sold for hours identified in [1].
[3]: Average hour-ahead ancillary services sold for hours identified in [1].
[4]: Calculated as [2] - [3].
[5]: Calculated as [4] / [2].
[6]: Number of peak hours in period where total day-ahead ancillary service sales are less than or equal to total hour-ahead ancillary service sales for scheduling coordinator identifier.
[7]: Average day-ahead ancillary services sold for hours identified in [6].
[8]: Average hour-ahead ancillary services sold for hours identified in [6].
[9]: Calculated as [2] - [8].
[10]: Calculated as total peak hours in period - [1] - [6].
[11]: For [2] - [5] and [9], weighted average weighted by [1]. For [7] - [8], weighted average weighted by [6].

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Table G-2
Ancillary Services Buyback Summary (Importers - Peak Hours)

Panel A: 1/1/00 - 4/30/00

Scheduling Coordinator	*When Buyback Occurs*					*When No Buyback Occurs*				
	Number of Hours	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*Average Buyback MW*	*Average Buyback % of DA Sales*	*Number of Hours*	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*DA AS Sales When Buyback Occurs Less HA AS Sales When No Buyback Occurs (MW)*	*Number of Hours with No AS Sales*
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*
ENRON Power Marketing Inc	184	63.1	27.7	35.5	56.2%	1,144	31.9	38.3	24.8	304
California Power Exchange	43	106.8	99.4	7.4	7.0%	1,439	83.3	98.4	8.4	150
Sempra Energy Trading Corporation	45	62.8	58.9	3.9	6.2%	1,523	39.0	40.7	22.1	64
City of Pasadena	11	16.6	14.3	2.3	13.9%	118	14.1	14.1	2.5	1,503
British Columbia Power Exchange	9	78.2	44.9	33.3	42.5%	355	107.1	107.1	-28.9	1,268
Automated Power Exchange, Inc	18	5.8	5.3	0.5	8.9%	242	4.8	4.8	1.0	1,372
Bonneville Power Administration	6	69.1	17.9	51.2	74.1%	301	84.2	85.8	-16.7	1,325
Arizona Public Service Company	3	24.6	24.6	0.0	0.1%	159	31.3	59.1	-34.5	1,470
Modesto Irrigation District	5	48.8	48.8	0.0	0.1%	322	24.3	30.3	18.5	1,305
Puget Sound Energy	1	75.0	74.6	0.4	0.5%	213	66.2	66.2	8.8	1,418
Totals (Weighted by Hours) [11]	**325**	**64.1**	**40.5**	**23.6**	**36.8%**	**5,816**	**53.1**	**59.7**	**17.2**	**10,179**

Panel B: 5/1/00 - 10/1/00

Scheduling Coordinator	*When Buyback Occurs*					*When No Buyback Occurs*				
	Number of Hours	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*Average Buyback MW*	*Average Buyback % of DA Sales*	*Number of Hours*	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*DA AS Sales When Buyback Occurs Less HA AS Sales When No Buyback Occurs (MW)*	*Number of Hours with No AS Sales*
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*
ENRON Power Marketing Inc	380	191.7	70.6	121.1	63.2%	1,524	47.2	59.3	132.4	160
Sempra Energy Trading Corporation	204	181.2	40.8	140.4	77.5%	1,797	54.9	70.2	111.0	63
Coral Power, LLC	183	118.4	7.0	111.4	94.1%	625	20.2	25.1	93.3	1,256
British Columbia Power Exchange	96	509.4	371.4	138.0	27.1%	1,502	318.0	435.9	73.5	466
California Power Exchange	59	113.5	77.3	36.2	31.9%	1,629	115.4	191.1	-77.6	376
Puget Sound Energy	36	181.2	125.5	55.6	30.7%	485	172.2	172.7	8.5	1,543
Modesto Irrigation District	36	39.1	24.4	14.7	37.6%	1,281	30.6	40.8	-1.8	747
Avista Energy Inc	30	153.5	122.8	30.7	20.0%	603	41.0	112.7	40.8	1,431
City of Azusa	26	5.8	0.0	5.8	100.0%	192	4.3	6.1	-0.3	1,846
Bonneville Power Administration	15	287.2	271.4	15.8	5.5%	1,553	150.2	247.7	39.4	496
City of Vernon	14	22.0	17.8	4.2	19.1%	272	18.9	21.5	0.5	1,778
Arizona Public Service Company	7	73.1	0.0	73.1	100.0%	230	38.6	143.2	-70.1	1,827
City of Glendale	5	18.4	0.0	18.4	100.0%	0.0	N/A	N/A	N/A	2,059
Totals (Weighted by Hours) [11]	**1,091**	**187.9**	**82.5**	**105.3**	**56.1%**	**11,693**	**106.4**	**156.2**	**86.2**	**14,048**

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Table G-2
Ancillary Services Buyback Summary (Importers - Peak Hours)

Panel C: 10/2/00 - 1/17/01

Scheduling Coordinator	*When Buyback Occurs*					*When No Buyback Occurs*			*DA AS Sales When Buyback Occurs Less HA AS Sales When No Buyback Occurs (MW)*	*Number of Hours with No AS Sales*
	Number of Hours	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*Average Buyback MW*	*Average Buyback % of DA Sales*	*Number of Hours*	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*		
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*
Coral Power, LLC	444	211.5	0.0	211.5	100.0%	70.0	210.2	211.6	-0.2	926
Sempra Energy Trading Corporation	155	154.8	26.2	128.6	83.1%	1,221.0	17.2	39.4	115.3	64
Avista Energy Inc	85	84.6	23.2	61.4	72.6%	716.0	55.5	99.8	-15.2	639
California Power Exchange	75	255.4	168.4	87.1	34.1%	1,305.0	240.8	328.0	-72.6	60
Modesto Irrigation District	57	29.6	3.6	25.9	87.8%	577.0	24.5	32.1	-2.6	806
City of Glendale	29	76.8	55.5	21.3	27.7%	502.0	33.0	38.9	37.9	909
ENRON Power Marketing Inc	25	39.5	30.2	9.3	23.5%	687.0	28.6	37.7	1.8	728
British Columbia Power Exchange	13	371.8	230.6	141.2	38.0%	761.0	231.0	434.4	-62.6	666
City of Azusa	8	2.5	0.0	2.5	100.0%	45.0	1.8	3.0	-0.5	1,387
City of Vernon	3	18.7	17.0	1.6	8.7%	383.0	15.2	16.9	1.8	1,054
Portland General Electric Company	1	25.0	0.0	25.0	100.0%	11.0	9.1	39.8	-14.8	1,428
Totals (Weighted by Hours) [11]	**895**	**172.1**	**27.1**	**145.0**	**84.2%**	**6,278**	**99.0**	**153.6**	**12.6**	**8,667**

Panel D: 1/18/01 - 6/19/01

Scheduling Coordinator	*When Buyback Occurs*					*When No Buyback Occurs*			*DA AS Sales When Buyback Occurs Less HA AS Sales When No Buyback Occurs (MW)*	*Number of Hours with No AS Sales*
	Number of Hours	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*	*Average Buyback MW*	*Average Buyback % of DA Sales*	*Number of Hours*	*Average Day-Ahead AS Sales (MW)*	*Average Hour-Ahead AS Sales (MW)*		
	[1]	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*	*[8]*	*[9]*	*[10]*
Modesto Irrigation District	1,779	46.6	0.0	46.6	100.0%	0.0	N/A	N/A	N/A	301
Avista Energy Inc	534	108.6	0.5	108.1	99.5%	18.0	48.6	48.6	60.0	1,528
Sempra Energy Trading Corporation	565	140.2	2.3	137.8	98.3%	141.0	33.3	37.2	103.0	1,374
Coral Power, LLC	154	204.4	0.0	204.4	100.0%	0.0	N/A	N/A	N/A	1,926
City of Azusa	102	10.3	0.0	10.3	100.0%	0.0	N/A	N/A	N/A	1,978
Calpine Energy Services	24	41.7	0.0	41.7	100.0%	0.0	N/A	N/A	N/A	2,056
Totals (Weighted by Hours) [11]	**3,158**	**80.3**	**0.5**	**79.8**	**99.4%**	**159**	**35.0**	**38.5**	**82.1**	**9,163**

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Table G-2
Ancillary Services Buyback Summary (Importers - Peak Hours)

Notes and Sources:
Calculations derived from imports data produced in response to CAL-ISO 4.
Ancillary services defined as spinning, non-spinning, and replacement reserves.
[1]: Number of peak hours in period where total day-ahead ancillary service sales exceed total hour-ahead ancillary service sales for scheduling coordinator identifier.
[2]: Average day-ahead ancillary services sold for hours identified in [1].
[3]: Average hour-ahead ancillary services sold for hours identified in [1].
[4]: Calculated as [2] - [3].
[5]: Calculated as [4] / [2].
[6]: Number of peak hours in period where total day-ahead ancillary service sales are less than or equal to total hour-ahead ancillary service sales for scheduling coordinator identifier.
[7]: Average day-ahead ancillary services sold for hours identified in [6].
[8]: Average hour-ahead ancillary services sold for hours identified in [6].
[9]: Calculated as [2] - [8].
[10]: Calculated as total peak hours in period - [1] - [6].
[11]: For [2] - [5] and [9], weighted average weighted by [1]. For [7] - [8], weighted average weighted by [6].

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Table G-3
Ancillary Service Buyback for the Most Active Suppliers (Peak Hours)

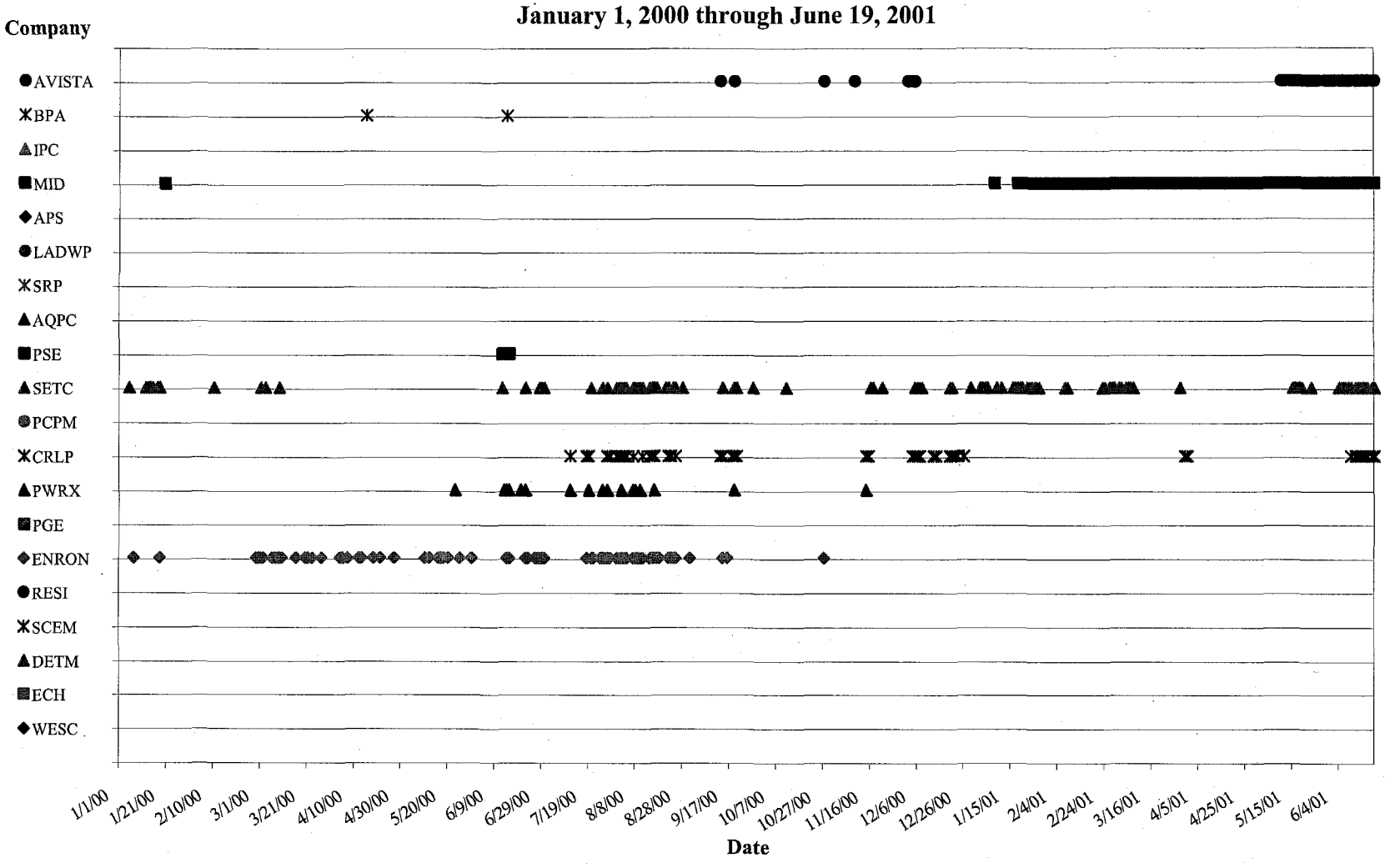
	1/1/00 - 4/30/00 1,632 hrs	5/1/00 - 10/1/00 2,064 hrs	10/2/00 - 1/17/01 1,440 hrs	1/18/01 - 6/19/01 2,080 hrs
Enron				
Number of Hours When Buyback Occurs	184 hrs	380 hrs	25 hrs	na
Average Hourly Buyback	35.5 MW	121.1 MW	9.3 MW	na
Average Hourly Day-Ahead Sales When Buyback Occurs	63.1 MW	191.7 MW	39.5 MW	na
Average Hourly Buyback as Percentage of Average Day-Ahead Sales	56.2%	63.2%	23.5%	na
Number of Hours When No Buyback Occurs	1,144 hrs	1,524 hrs	687 hrs	na
Average Hourly Ultimate Sales (HA) When No Buyback Occurs	38.3 MW	59.3 MW	37.7 MW	na
DA Sales during Buyback Hours as a Percentage of Ultimate Sales during No Buyback Hours	164.6%	323.5%	104.8%	na
Amount by which Day-Ahead Sales During Buyback Hours Exceed Ultimate Sales During No Buyback Hours	24.8 MW	132.4 MW	1.8 MW	na
Buyback hours as percentage of total ancillary service hours	13.9%	20.0%	5.5%	na
Sempra				
Number of Hours When Buyback Occurs	45 hrs	204 hrs	155 hrs	565 hrs
Average Hourly Buyback	3.9 MW	140.4 MW	128.6 MW	137.8 MW
Average Hourly Day-Ahead Sales When Buyback Occurs	62.8 MW	181.2 MW	154.8 MW	140.2 MW
Average Hourly Buyback as Percentage of Average Day-Ahead Sales	6.2%	77.5%	83.1%	98.3%
Number of Hours When No Buyback Occurs	1,523 hrs	1,797 hrs	1,221 hrs	141 hrs
Average Hourly Ultimate Sales (HA) When No Buyback Occurs	40.7 MW	70.2 MW	39.4 MW	37.2 MW
DA Sales during Buyback Hours as a Percentage of Ultimate Sales during No Buyback Hours	154.3%	258.1%	392.4%	377.3%
Amount by which Day-Ahead Sales During Buyback Hours Exceed Ultimate Sales During No Buyback Hours	22.1 MW	111.0 MW	115.3 MW	103. MW
Buyback hours as percentage of total ancillary service hours	2.9%	10.2%	11.3%	80.0%
Coral				
Number of Hours When Buyback Occurs	na	183 hrs	444 hrs	154 hrs
Average Hourly Buyback	na	111.4 MW	211.5 MW	204.4 MW
Average Hourly Day-Ahead Sales When Buyback Occurs	na	118.4 MW	211.5 MW	204.4 MW
Average Hourly Buyback as Percentage of Average Day-Ahead Sales	na	94.1%	100.0%	100.0%
Number of Hours When No Buyback Occurs	na	625 hrs	70 hrs	0 hrs
Average Hourly Ultimate Sales (HA) When No Buyback Occurs	na	25.1 MW	211.6 MW	na
DA Sales during Buyback Hours as a Percentage of Ultimate Sales during No Buyback Hours	na	471.6%	99.9%	na
Amount by which Day-Ahead Sales During Buyback Hours Exceed Ultimate Sales During No Buyback Hours	na	93.3 MW	-.2 MW	na
Buyback hours as percentage of total ancillary service hours	na	22.6%	86.4%	100.0%
PowerEx				
Number of Hours When Buyback Occurs	9 hrs	96 hrs	13 hrs	na
Average Hourly Buyback	33.3 MW	138. MW	141.2 MW	na
Average Hourly Day-Ahead Sales When Buyback Occurs	78.2 MW	509.4 MW	371.8 MW	na
Average Hourly Buyback as Percentage of Average Day-Ahead Sales	42.5%	27.1%	38.0%	na
Number of Hours When No Buyback Occurs	355 hrs	1,502 hrs	761 hrs	na
Average Hourly Ultimate Sales (HA) When No Buyback Occurs	107.1 MW	435.9 MW	434.4 MW	na
DA Sales during Buyback Hours as a Percentage of Ultimate Sales during No Buyback Hours	73.1%	116.9%	85.6%	na
Amount by which Day-Ahead Sales During Buyback Hours Exceed Ultimate Sales During No Buyback Hours	-28.9 MW	73.5 MW	-62.6 MW	na
Buyback hours as percentage of total ancillary service hours	2.5%	6.0%	1.7%	na

Table G-3
Ancillary Service Buyback for the Most Active Suppliers (Peak Hours)

	1/1/00 - 4/30/00 1,632 hrs	5/1/00 - 10/1/00 2,064 hrs	10/2/00 - 1/17/01 1,440 hrs	1/18/01 - 6/19/01 2,080 hrs
Modesto Irrigation District				
Number of Hours When Buyback Occurs	5 hrs	36 hrs	57 hrs	1,779 hrs
Average Hourly Buyback	0.0 MW	14.7 MW	25.9 MW	46.6 MW
Average Hourly Day-Ahead Sales When Buyback Occurs	48.8 MW	39.1 MW	29.6 MW	46.6 MW
Average Hourly Buyback as Percentage of Average Day-Ahead Sales	0.1%	37.6%	87.8%	100.0%
Number of Hours When No Buyback Occurs	322 hrs	1,281 hrs	577 hrs	0 hrs
Average Hourly Ultimate Sales (HA) When No Buyback Occurs	30.3 MW	40.8 MW	32.1 MW	na
DA Sales during Buyback Hours as a Percentage of Ultimate Sales during No Buyback Hours	161.2%	95.6%	92.0%	na
Amount by which Day-Ahead Sales During Buyback Hours Exceed Ultimate Sales During No Buyback Hours	18.5 MW	-1.8 MW	-2.6 MW	na
Buyback hours as percentage of total ancillary service hours	1.5%	2.7%	9.0%	100.0%
Avista				
Number of Hours When Buyback Occurs	na	30 hrs	85 hrs	534 hrs
Average Hourly Buyback	na	30.7 MW	61.4 MW	108.1 MW
Average Hourly Day-Ahead Sales When Buyback Occurs	na	153.5 MW	84.6 MW	108.6 MW
Average Hourly Buyback as Percentage of Average Day-Ahead Sales	na	20.0%	72.6%	99.5%
Number of Hours When No Buyback Occurs	na	603 hrs	716 hrs	18 hrs
Average Hourly Ultimate Sales (HA) When No Buyback Occurs	na	112.7 MW	99.8 MW	48.6 MW
DA Sales during Buyback Hours as a Percentage of Ultimate Sales during No Buyback Hours	na	136.2%	84.8%	223.3%
Amount by which Day-Ahead Sales During Buyback Hours Exceed Ultimate Sales During No Buyback Hours	na	40.8 MW	-15.2 MW	60. MW
Buyback hours as percentage of total ancillary service hours	na	4.7%	10.6%	96.7%
Azusa				
Number of Hours When Buyback Occurs	na	26 hrs	8 hrs	102 hrs
Average Hourly Buyback	na	5.8 MW	2.5 MW	10.3 MW
Average Hourly Day-Ahead Sales When Buyback Occurs	na	5.8 MW	2.5 MW	10.3 MW
Average Hourly Buyback as Percentage of Average Day-Ahead Sales	na	100.0%	100.0%	100.0%
Number of Hours When No Buyback Occurs	na	192 hrs	45 hrs	0 hrs
Average Hourly Ultimate Sales (HA) When No Buyback Occurs	na	6.1 MW	3.0 MW	na
DA Sales during Buyback Hours as a Percentage of Ultimate Sales during No Buyback Hours	na	95.8%	84.0%	na
Amount by which Day-Ahead Sales During Buyback Hours Exceed Ultimate Sales During No Buyback Hours	na	-0.3 MW	-0.5 MW	na
Buyback hours as percentage of total ancillary service hours	na	11.9%	15.1%	100.0%

Notes and Sources:
Based on results from Table G-2.

Figure G-1
Get Shorty Occurrences
January 1, 2000 through June 19, 2001



Source is generation data produced in response to Data Request CAL-ISO-4.

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Table H-1
Ancillary Services Double Selling by ISO Internal Generation
(includes Suppliers who Double Sold at least 10% of Ancillary Services Awarded)
January 2000 - September 2000

Month Supplier	AS Double Sold (MW) [1]	Total AS (MW) [2]	% of AS Double Sold [3]	Double Selling Hours [4]	Hours when AS Sold [5]	% of Hours Double Sold [6]
January 2000						
Southern Company Energy Marketing, L.P.	147	286	52%	7	1,620	0%
February 2000						
Southern Company Energy Marketing, L.P.	504	4,333	12%	35	1,449	2%
March 2000						
Duke Energy Trading and Marketing, L.L.C.	2,368	7,750	31%	32	100	32%
April 2000						
Southern Company Energy Marketing, L.P.	401	3,086	13%	10	1,056	1%
Sub-Total for January 2000 through April 2000	3,421	15,454	22%	84	4,225	2%
May 2000						
Duke Energy Trading and Marketing, L.L.C.	518	5,100	10%	26	140	19%
Southern Company Energy Marketing, L.P.	1,322	5,246	25%	31	95	33%
June 2000						
Duke Energy Trading and Marketing, L.L.C.	2,549	22,003	12%	188	543	35%
Reliant Energy Services, Inc.	6,458	50,464	13%	205	590	35%
Southern California Edison Company	369	2,914	13%	32	119	27%
Southern Company Energy Marketing, L.P.	10,292	29,909	34%	261	489	53%
July 2000						
Duke Energy Trading and Marketing, L.L.C.	1,139	7,568	15%	141	322	44%
Southern Company Energy Marketing, L.P.	10,948	46,225	24%	245	692	35%
August 2000						
Dynegy/Electric Clearinghouse	23,763	164,599	14%	1,845	4,930	37%
Reliant Energy Services, Inc.	4,904	41,453	12%	191	699	27%
Southern Company Energy Marketing, L.P.	26,652	113,832	23%	682	1,515	45%
September 2000						
Dynegy/Electric Clearinghouse	4,054	33,169	12%	375	1,145	33%
San Diego Gas and Electric Company	461	1,757	26%	34	48	71%
Southern Company Energy Marketing, L.P.	3,294	29,997	11%	160	518	31%
Sub-Total for May 2000 through September 2000	96,723	554,236	17%	4,416	11,845	37%

Notes & Sources:

[1]: Total Ancillary Services double sold amount from unit hours in which aggregate of spin, non-spin & replacement reserves hour-ahead final schedules exceeded available capacity and unit was not awarded regulation by CAISO; from Response to Data Request CAL-ISO-4 and ISO data provided by AG.

[2]: Aggregate of spin, non-spin and replacement reserves hour-ahead final schedules; from Response to Data Request CAL-ISO-4.

[3]: [1] / [2]

[4]: Unit hours in which aggregate of spin, non-spin & replacement reserves hour-ahead final schedules exceeded available capacity and unit was not awarded regulation by CAISO; from Response to Data Request CAL-ISO-4.

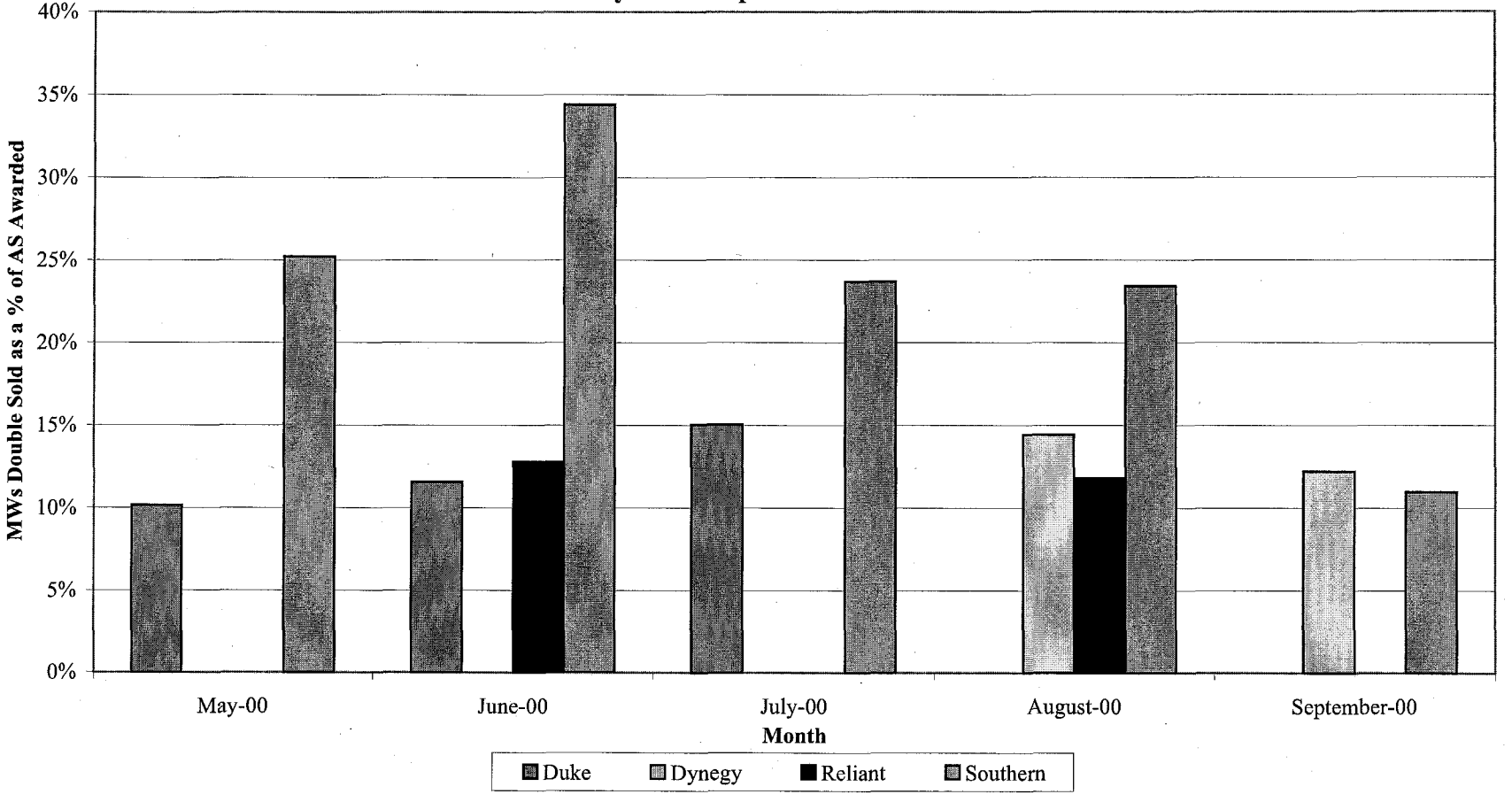
[5]: Unit hours in which spin, no-spin or replacement reserves services sold; from Response to Data Request CAL-ISO-4.

[6]: [4] / [5]

[7]: Available capacity is taken as maximum generating capacity less hour-ahead final schedule, supplemental energy supply, uninstructed deviations & schedule change.

[8]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure H-1
Ancillary Services Double Selling by ISO-Internal Generators
(includes Suppliers who Double Sold at least 10% of Ancillary Services Awarded)
May 2000 - September 2000



Notes & Sources: Ancillary Services double sold amount applies to unit hours in which aggregate of spin, non-spin & replacement reserves hour-ahead final schedules exceeded available capacity and unit was not awarded regulation by CAISO. Available capacity is taken as maximum generating capacity less hour-ahead final schedule, supplemental energy supply, uninstructed deviations & schedule change; all data taken from Response to Data Request CAL-ISO-4.

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Table I-1
Scheduling of False Load
Average Metered and Scheduled Load (MW) during On-Peak Hours
by Period for the Most Active Schedule Coordinators

	January 1, 2000 - April 30, 2000				
Schedule Coordinator	*Average Metered Load* [1]	*Average Scheduled Load* [2]	*Difference* [3]	*Number of Hours with False Load* [4]	*Percent of Hours with False Load* [5]
Southern Company Energy Marketing, L.P.	0	94	94	549	44.56%
ENRON Power Marketing, Inc.	538	724	187	874	53.55%
PG&E Energy Services Corporation	465	616	150	786	48.16%
California Polar Power Brokers, L.L.C.	1	124	124	1134	69.49%
NewEnergy Inc.	700	803	103	443	37.93%
Sempra Energy Trading Corporation	35	136	101	1052	64.46%
Idaho Power Company	11	26	15	564	34.56%
Salt River Project	461	535	75	546	33.46%

	May 1, 2000 - October 1, 2000				
Schedule Coordinator	*Average Metered Load* [1]	*Average Scheduled Load* [2]	*Difference* [3]	*Number of Hours with False Load* [4]	*Percent of Hours with False Load* [5]
Southern Company Energy Marketing, L.P.	0	217	217	1216	59.84%
City of Anaheim	147	439	292	660	31.98%
City of Pasadena	8	184	176	438	21.22%
City of Riverside	272	347	74	585	28.34%
ENRON Power Marketing, Inc.	919	1,330	411	1898	91.96%
British Columbia Power Exchange Corporation	255	613	358	1255	60.80%
Hafslund Energy Trading L.L.C.	0	223	223	674	43.43%
Sempra Energy Trading Corporation	46	231	184	1473	71.37%
California Polar Power Brokers, L.L.C.	0	162	162	426	20.64%
PG&E Energy Trading Power, L.P.	0	155	155	1131	65.45%
Coral Power, L.L.C.	33	124	91	647	31.35%

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Table I-1
Scheduling of False Load
Average Metered and Scheduled Load (MW) during On-Peak Hours
by Period for the Most Active Schedule Coordinators

	October 2, 2000 - January 17, 2001				
Schedule Coordinator	*Average Metered Load* [1]	*Average Scheduled Load* [2]	*Difference* [3]	*Number of Hours with False Load* [4]	*Percent of Hours with False Load* [5]
Southern Company Energy Marketing, L.P.	0	242	242	716	59.67%
Duke Energy Trading and Marketing, L.L.C.	0	227	227	9	100.00%
Dynegy/Electric Clearinghouse	48	141	93	472	32.78%
City of Anaheim	1	352	351	1222	84.86%
City of Riverside	24	233	209	450	31.25%
City of Pasadena	0	151	151	1216	84.44%
British Columbia Power Exchange Corporation	212	720	508	736	51.11%
ENRON Power Marketing, Inc.	948	1,368	420	1077	74.79%
Sempra Energy Trading Corporation	0	262	262	746	51.81%
Hafslund Energy Trading L.L.C.	0	232	232	418	32.66%
PG&E Energy Trading Power, L.P.	0	230	230	710	49.31%
Puget Sound Energy	0	150	150	32	100.00%
Coral Power, L.L.C.	16	71	55	658	45.69%
Salt River Project	539	613	75	379	26.32%
Northern California Power Agency	36	103	68	356	24.72%

	January 18, 2001 - June 19, 2001				
Schedule Coordinator	*Average Metered Load* [1]	*Average Scheduled Load* [2]	*Difference* [3]	*Number of Hours with False Load* [4]	*Percent of Hours with False Load* [5]
City of Anaheim	13	341	328	1116	53.65%
City of Pasadena	0	150	150	1072	51.54%
El Paso Power Services Company	0	100	100	1	50.00%

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Table I-1
Scheduling of False Load
Average Metered and Scheduled Load (MW) during On-Peak Hours
by Period for the Most Active Schedule Coordinators

Notes:

[1] Average hourly MW of metered load during hours in which SC scheduled false load. Source: Response to CAL-ISO-28.
[2] Average hourly MW of scheduled load during hours in which SC scheduled false load. Source: Response to CAL-ISO-4.
[3] [2] - [1]
[4] Number of hours false load was scheduled.
[5] [4] as a proportion of hours in which either scheduled or metered load were greater than zero.

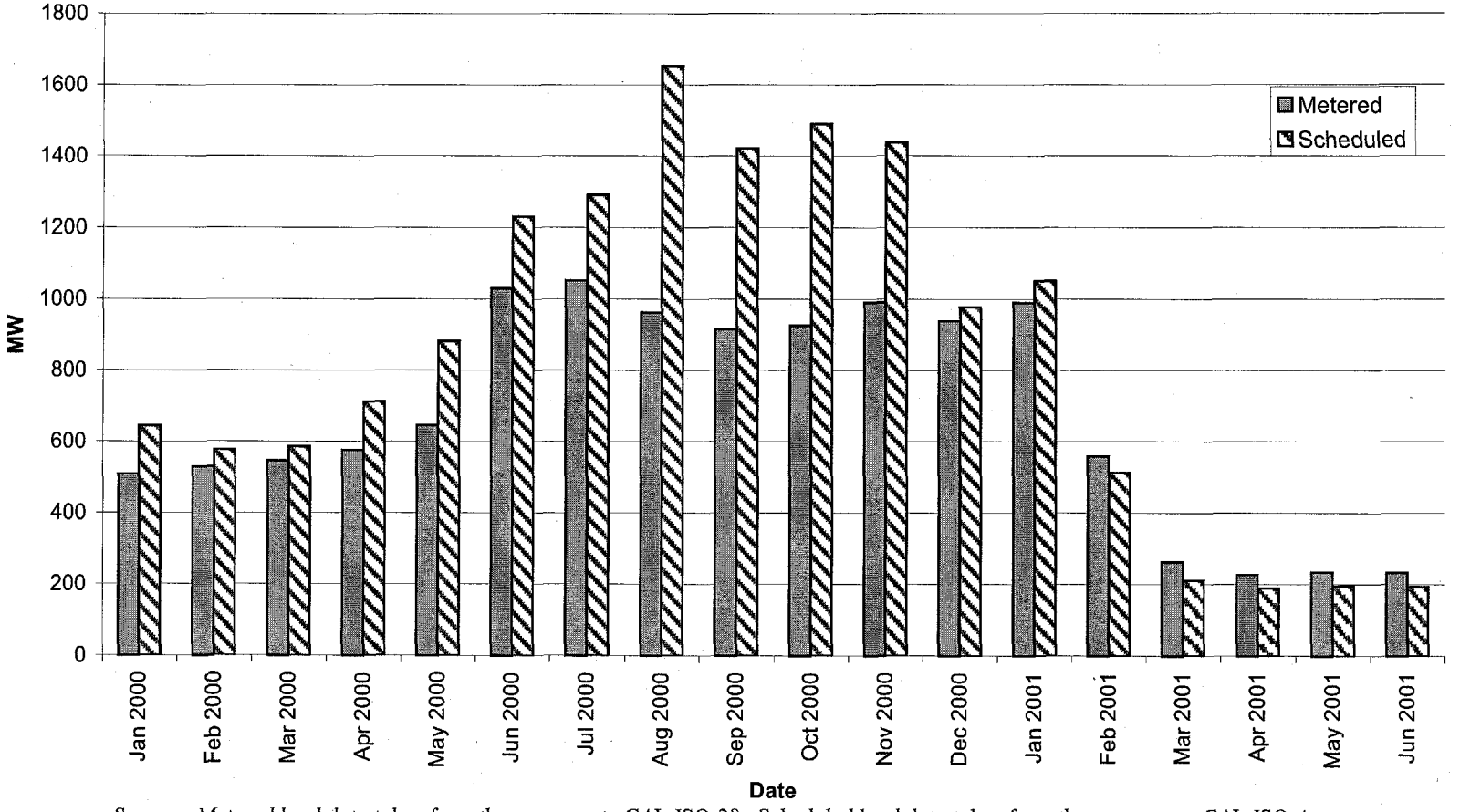
A scheduling coordinator was considered to have scheduled false load in an hour if scheduled load exceeded metered load by at least 50 MW or if scheduled load was at least twice metered load and scheduled load was greater than 10 MW.

Scheduling coordinators listed above scheduled false load in at least 20% of the on-peak hours during which they had either postive scheduled or metered load.

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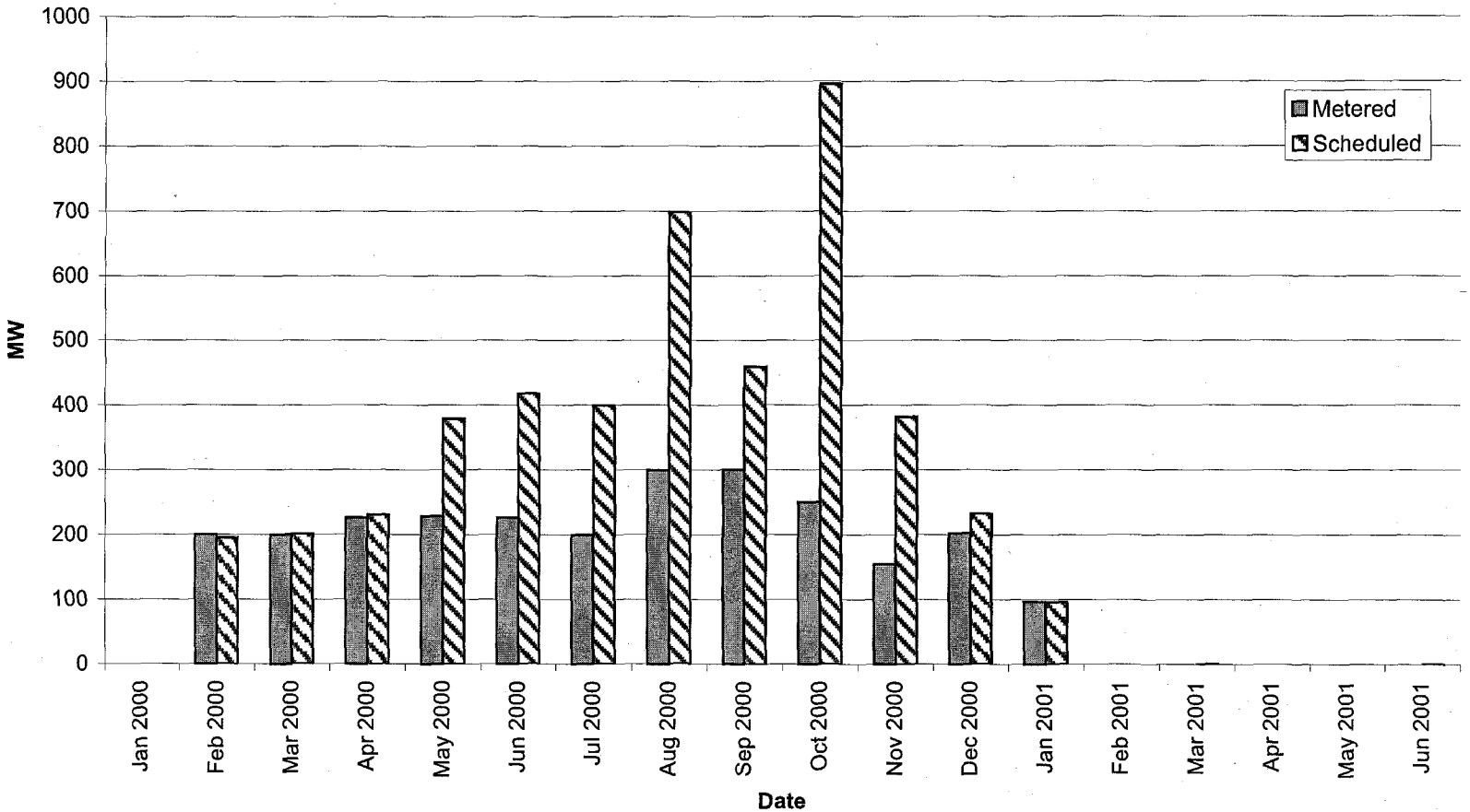
Figure I-1
Average On-Peak Scheduled and Metered Load by Month
ENRON Power Marketing, Inc.



Source: Metered load data taken from the response to CAL-ISO-28. Scheduled load data taken from the response to CAL-ISO-4. Scheduled load is hour ahead final scheduled load.

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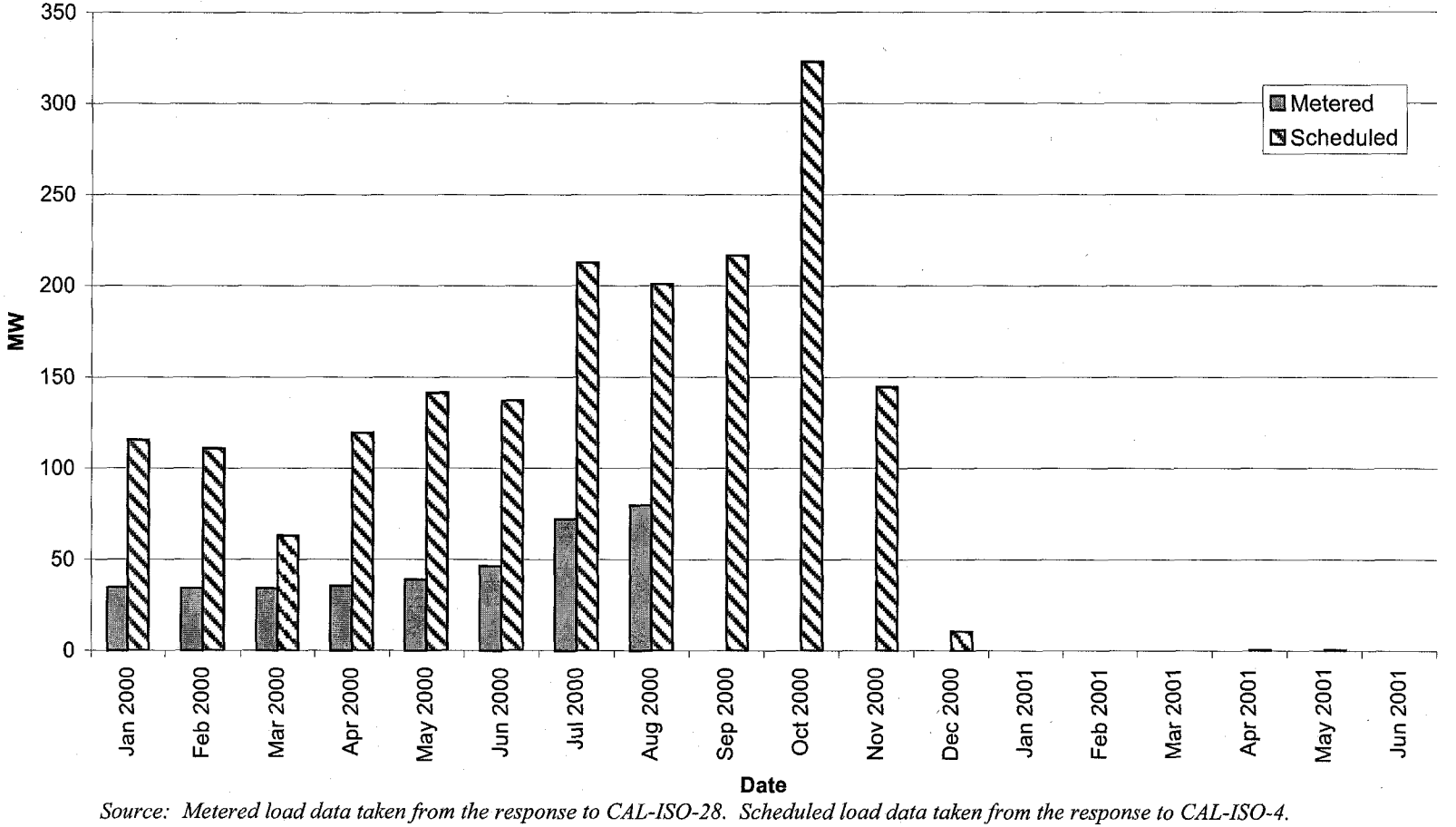
Figure I-2
Average On-Peak Scheduled and Metered Load by Month
British Columbia Power Exchange Corporation



Source: Metered load data taken from the response to CAL-ISO-28. Scheduled load data taken from the response to CAL-ISO-4. Scheduled load is hour ahead final scheduled load.

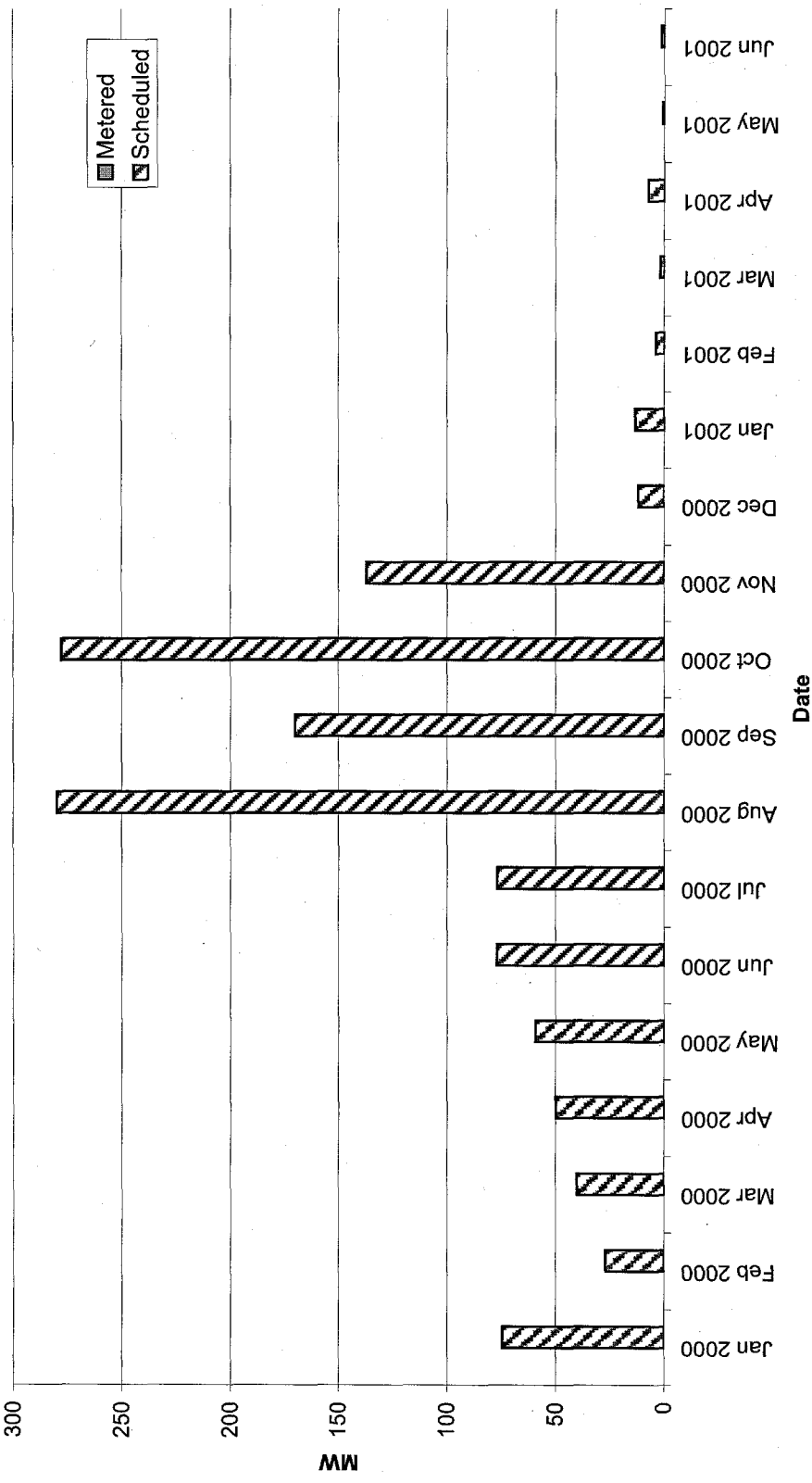
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Figure I-3
Average On-Peak Scheduled and Metered Load by Month
Sempra Energy Trading Corporation



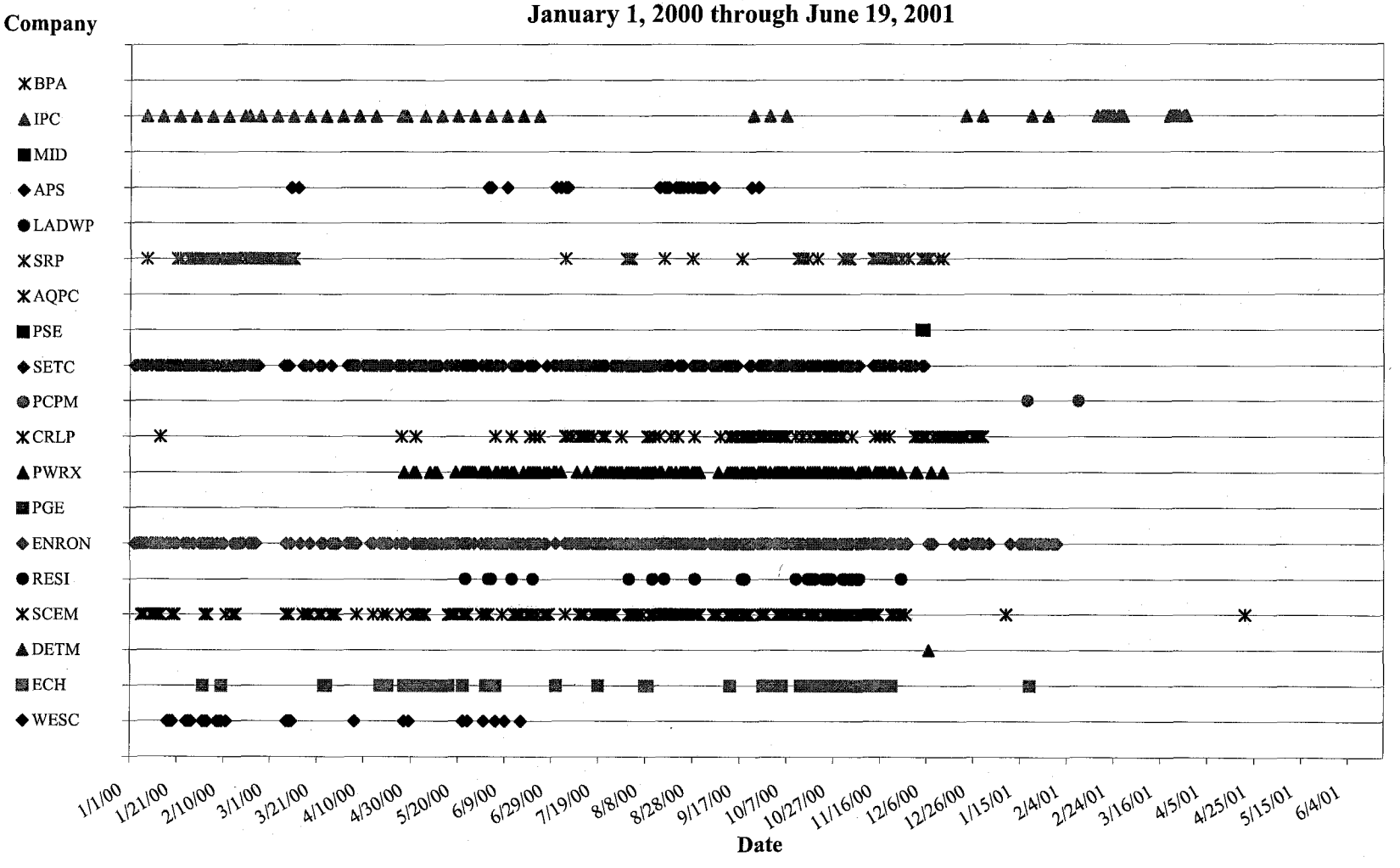
Source: Metered load data taken from the response to CAL-ISO-28. Scheduled load data taken from the response to CAL-ISO-4. Scheduled load is hour ahead final scheduled load.

Figure I-4
Average On-Peak Scheduled and Metered Load by Month
Southern Company Energy Marketing, L.P.



Source: Metered load data taken from the response to CAL-ISO-28. Scheduled load data taken from the response to CAL-ISO-4. Scheduled load is hour ahead final scheduled load.

Figure I-5
Fat Boy Occurrences
January 1, 2000 through June 19, 2001



Source is California ISO response to Data Requests CAL-ISO-28 and CAL-ISO-4.

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Table J-1
Summary of Suppliers with Significant Uninstructed Deviations (Jan. 2000 - Jun. 2001)

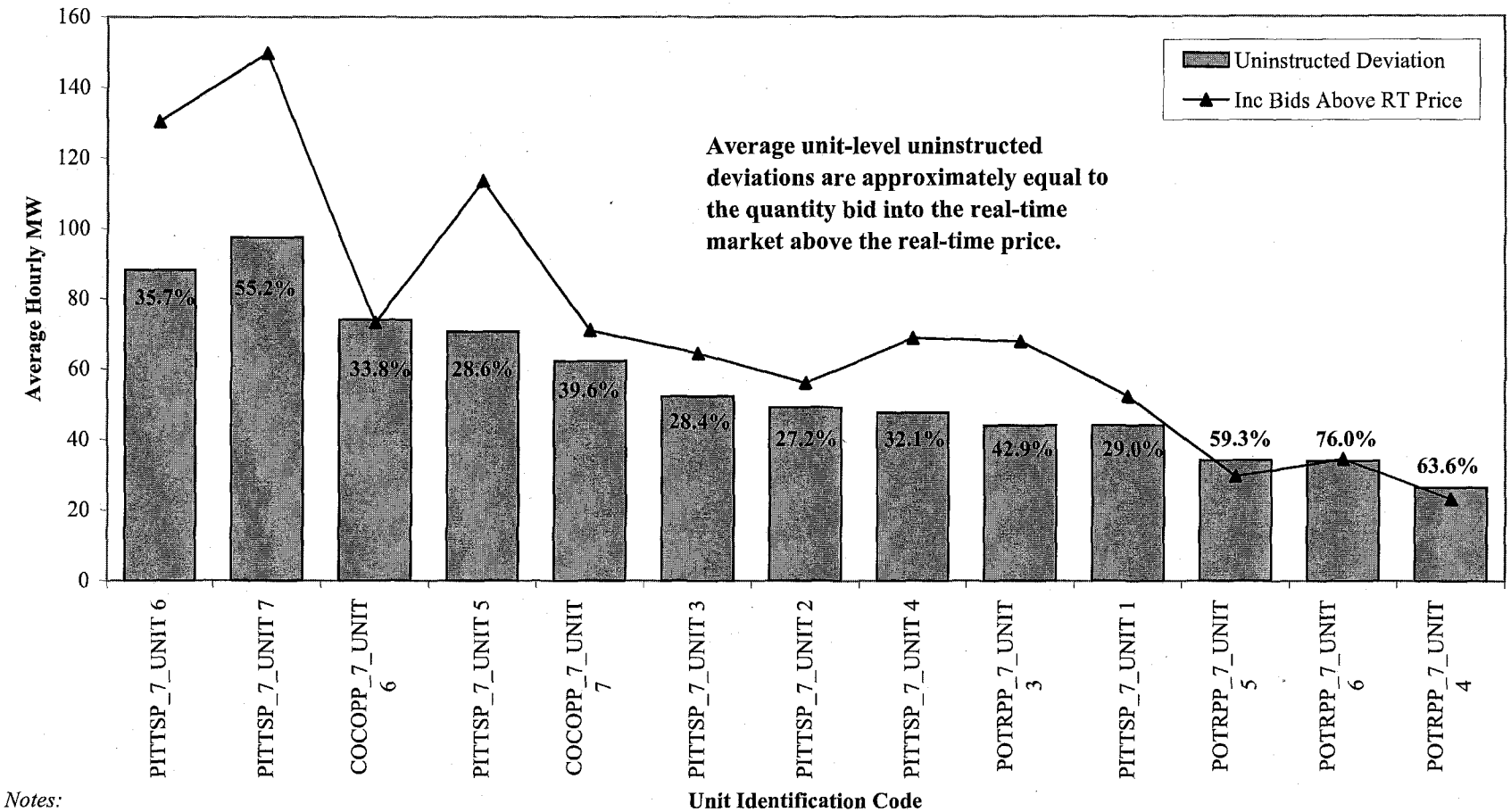
Month Supplier	*Portfolio Uninstructed Generation* [1]	*Portfolio Metered Generation* [2]	*Uninstructed as Percentage of Metered Generation* [3]	*Unit Hours When Uninstructed Generation Exceeds Minimum of 10 MW or 10% ofCapacity* [4]	*Threshold Unit Hours as Percentage of Active Unit Hours* [5]	*Average Hourly Uninstructed Generation During Threshold Hours* [6]	*Average Hourly Metered Generation During Threshold Hours* [7]	*Uninstructed as Percentage of Metered Generation During Threshold Hours* [8]
May 2000								
Southern Company Energy Marketing, L.P.	139,967	600,992	23.3%	1,402	33.4%	280	607	46.2%
June 2000								
Dynegy/Electric Clearinghouse	39,286	496,462	7.9%	1,700	21.6%	87	205	42.5%
Southern Company Energy Marketing, L.P.	102,406	873,843	11.7%	2,192	36.0%	235	624	37.6%
July 2000								
Southern Company Energy Marketing, L.P.	119,283	910,978	13.1%	2,346	36.4%	236	714	33.0%
August 2000								
Dynegy/Electric Clearinghouse	72,231	979,710	7.4%	3,115	27.8%	141	385	36.5%
Reliant Energy Services, Inc.	163,139	2,151,340	7.6%	4,048	44.6%	295	1,580	18.7%
Southern Company Energy Marketing, L.P.	207,194	1,355,190	15.3%	3,985	51.0%	319	1,145	27.9%
Total for May 2000 through September 2000	**843,506**	**7,368,514**	**11.4%**		**35.6%**	**240**	**873**	**27.5%**
November 2000								
Southern Company Energy Marketing, L.P.	94,378	1,196,153	7.9%	2,105	44.2%	170	890	19.0%
December 2000								
Dynegy/Electric Clearinghouse	77,024	548,133	14.1%	2,145	21.5%	204	329	62.2%
Total for October 2000 through December 2000	**171,402**	**1,744,286**	**9.8%**		**28.9%**	**187**	**607**	**30.8%**
February 2001								
Reliant Energy Services, Inc.	71,538	1,015,117	7.0%	1,508	27.3%	183	508	36.0%
April 2001								
San Diego Gas and Electric Company	4,358	22,030	19.8%	2,062	31.3%	6	14	42.2%
Total for January 2001 through June 2001	**75,895**	**1,037,146**	**7.3%**		**29.5%**	**81**	**223**	**36.3%**

Notes and Sources:
Calculations derived from data produced in CAL-ISO 4, CAL-ISO 7 and ISO Data provided by the CA Attorney General.
Uninstructed generation calculated as metered generation x GMMa - scheduled energy x GMMf - BEEP stack energy - schedule change - Out of Stack energy.
If a unit supplies day-ahead or hour-ahead regulation up or regulation down or is identified as a QF or Cogen, uninstructed is set to 0.
[1]: Total uninstructed generation (positive and negative) by supplier.
[2]: Total metered generation by supplier.
[3]: = [1] / [2].
[4]: Count of unit hours where uninstructed generation >= Min{10 MW, 10% x Capacity.}
[5]: [4] / all hours where metered generation or scheduled spinning, non-spinning, or replacement reserves exceeds zero.
[6]: Average hourly uninstructed generation for hours identified in [4].
[7]: Average hourly metered generation for hours identified in [4].
[8]: = [6] / [7].
Suppliers listed above have (1) average portfolio-wide uninstructed deviations in excess of 7% of metered generation (column [3]); and (2) average unit-level uninstructed generation that exceeded the smaller of 10 MW and one-tenth of unit capacity in excess of 20% of unit-hours (column[5]).

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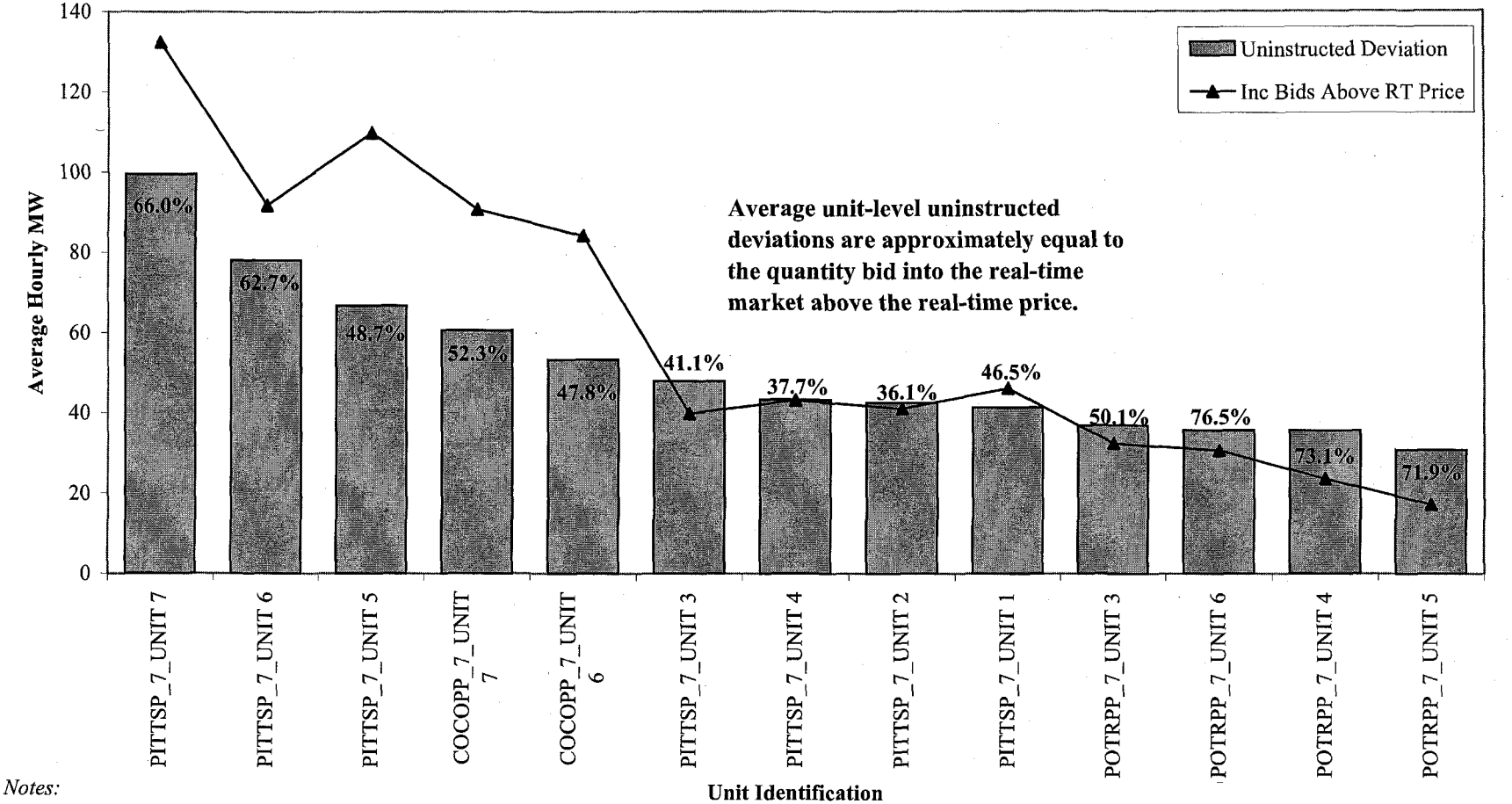
Figure J-1
Southern Company Unit-Level Uninstructed Deviations
July 2000



Notes:

Percentages represent hours of significantly positive uninstructed generation as a percentage of the hours when the unit was active.
Averages calculated over hours where uninstructed generation exceeded the smaller of 10 MW or one-tenth of unit capacity.
Hours during which a unit was awarded regulation up or down are excluded from the analysis

Figure J-2
Southern Company Unit-Level Uninstructed Deviations
August 2000



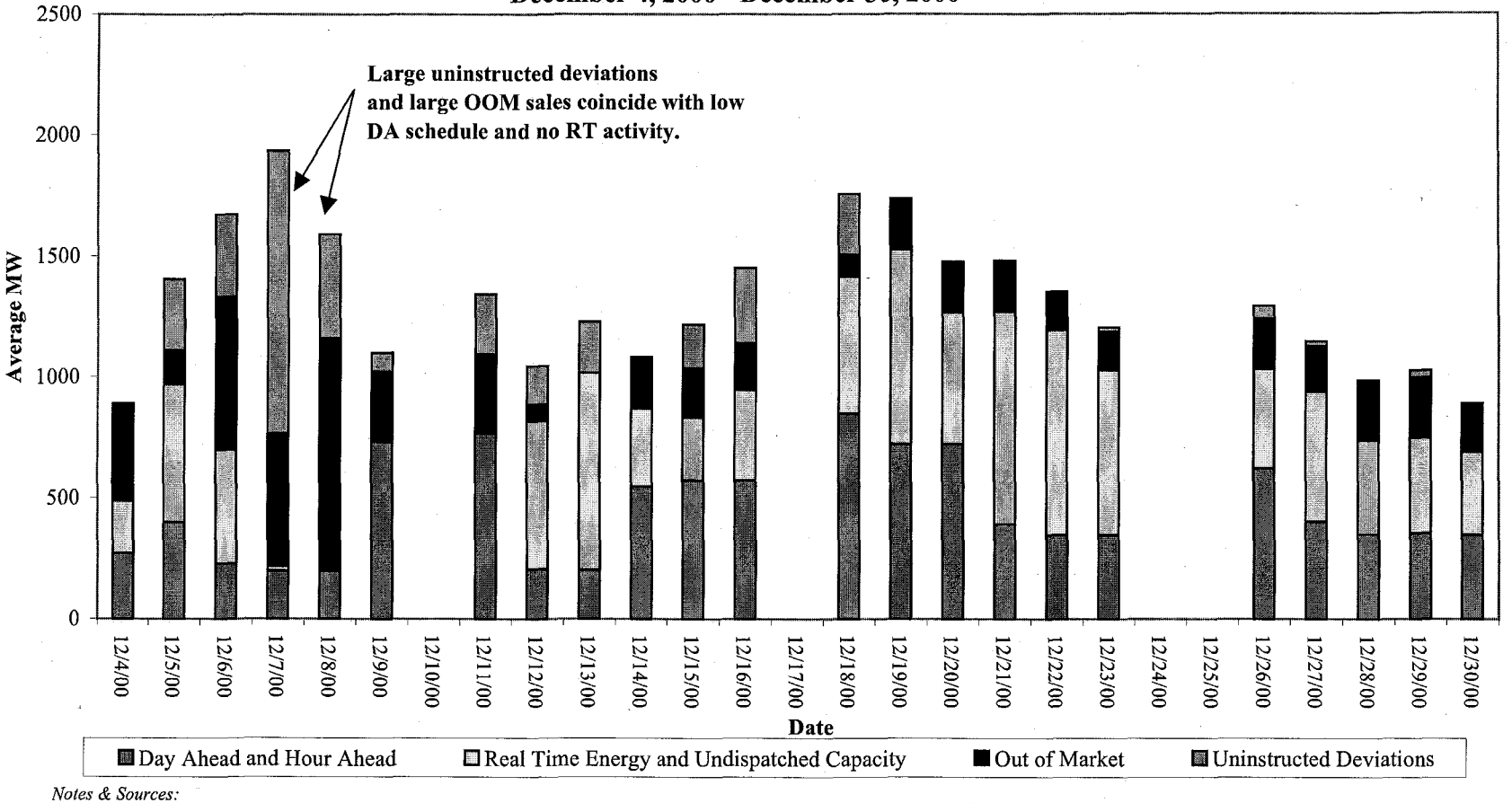
Notes:

Percentages represent hours of significantly positive uninstructed generation as a percentage of the hours when the unit was active.
Averages calculated over hours where uninstructed generation exceeded the smaller of 10 MW or one-tenth of unit capacity.
Hours during which a unit was awarded regulation up or down are excluded from the analysis

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Figure J-3
Average Megawatts Sold in California Markets (On-Peak)
Dynegy/Electric Clearinghouse
December 4, 2000 - December 30, 2000



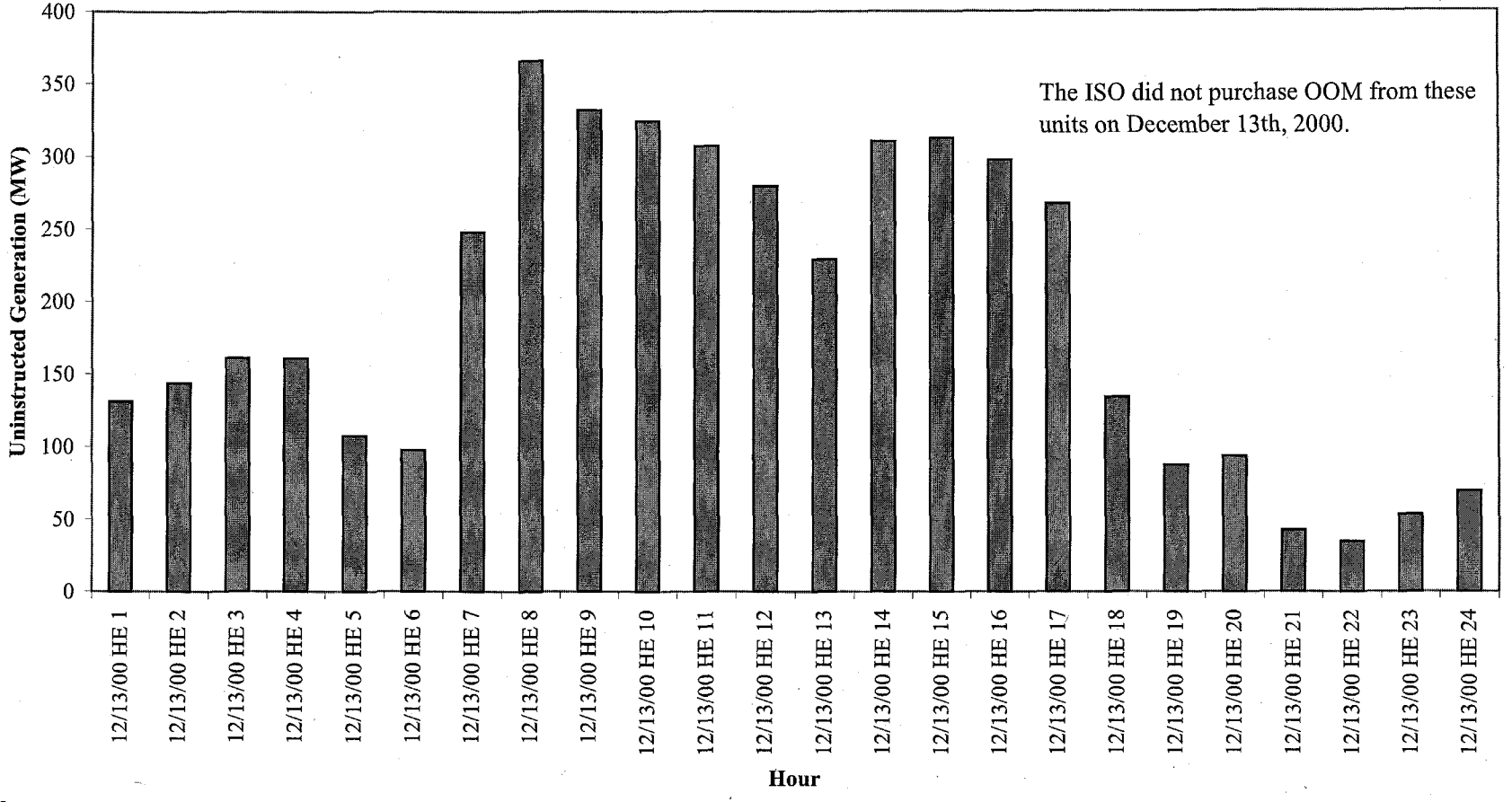
Notes & Sources:

[1]: Day-ahead, Hour-ahead, Real Time & Undispatched AS are output from generating units within California only; from Response to Data Request CAL-ISO-4 and ISO data provided by CA Attorney General.

[2]: OOM supply is output from generating units within California only; from Response to Data Request CAL-ISO-7.

[3]: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

Figure J-4
Dynegy Uninstructed Generation for December 13, 2000
Aggregate Hourly Data for Units Encina 1-3 and El Segundo 1-2



Note:
Uninstructed generation calculated as
$M_GEN \times GMM_A$ - $HA_MW \times GMM_F$ - SCH_CHG - BP_NS - BP_SP - BP_RP - BP_SE - Out of Stack Energy.

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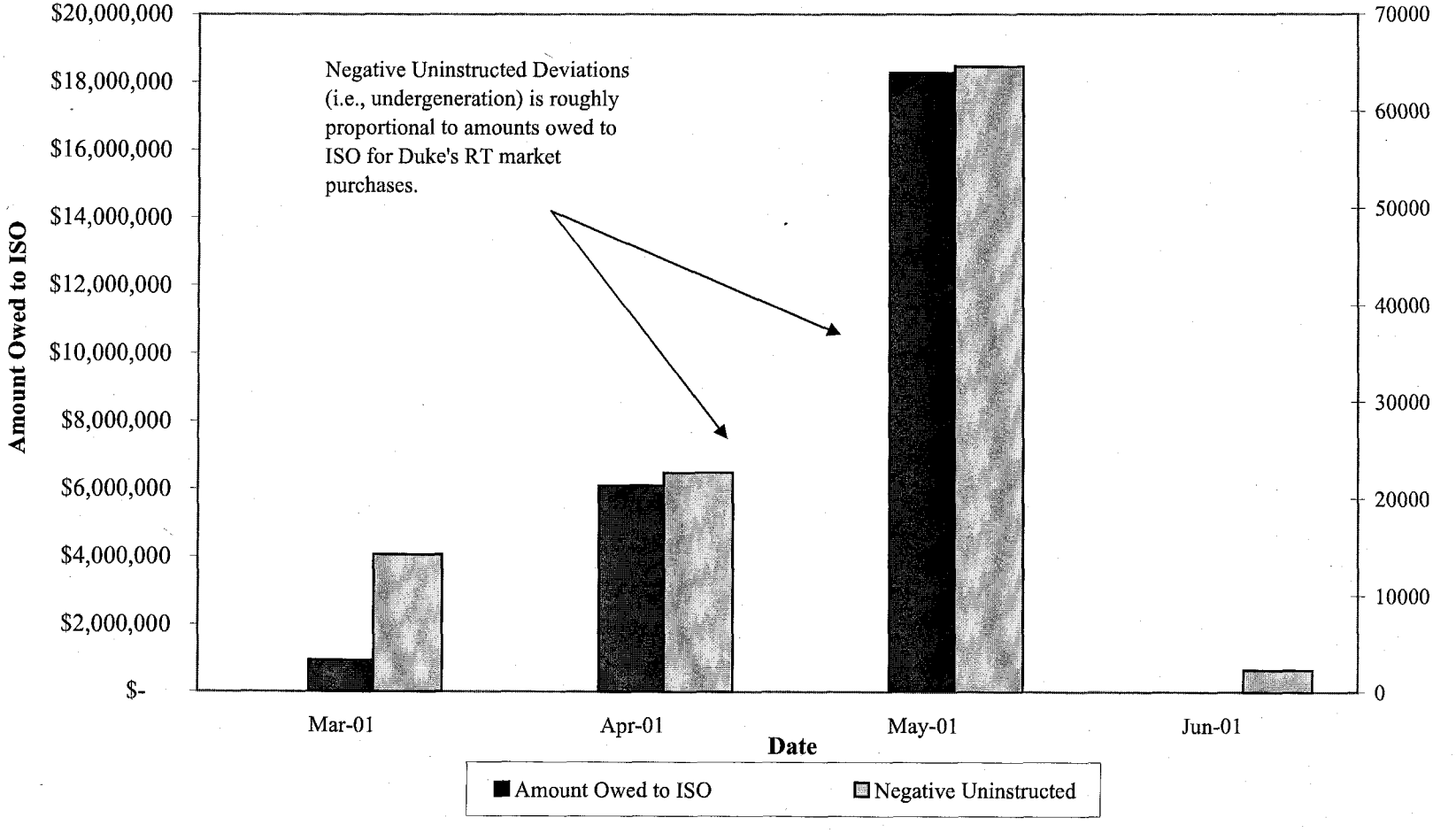
Table J-2
Amounts Owed to the ISO (Jan 2001 - Jun 2001)

	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01
Duke Energy and Trading	-	-	950,374	6,105,737	18,276,340	-
British Columbia Power Exchange	2,008,732	8,247,625	6,747,362	3,772,410	2,359,114	1,071,215
Idaho Power Company	1,844,912	2,141,699	11,043,347	4,353,864	2,501,228	613,769
City of Pasadena	-	-	-	3,386,384	-	-

Source: CAISO Certification Data.

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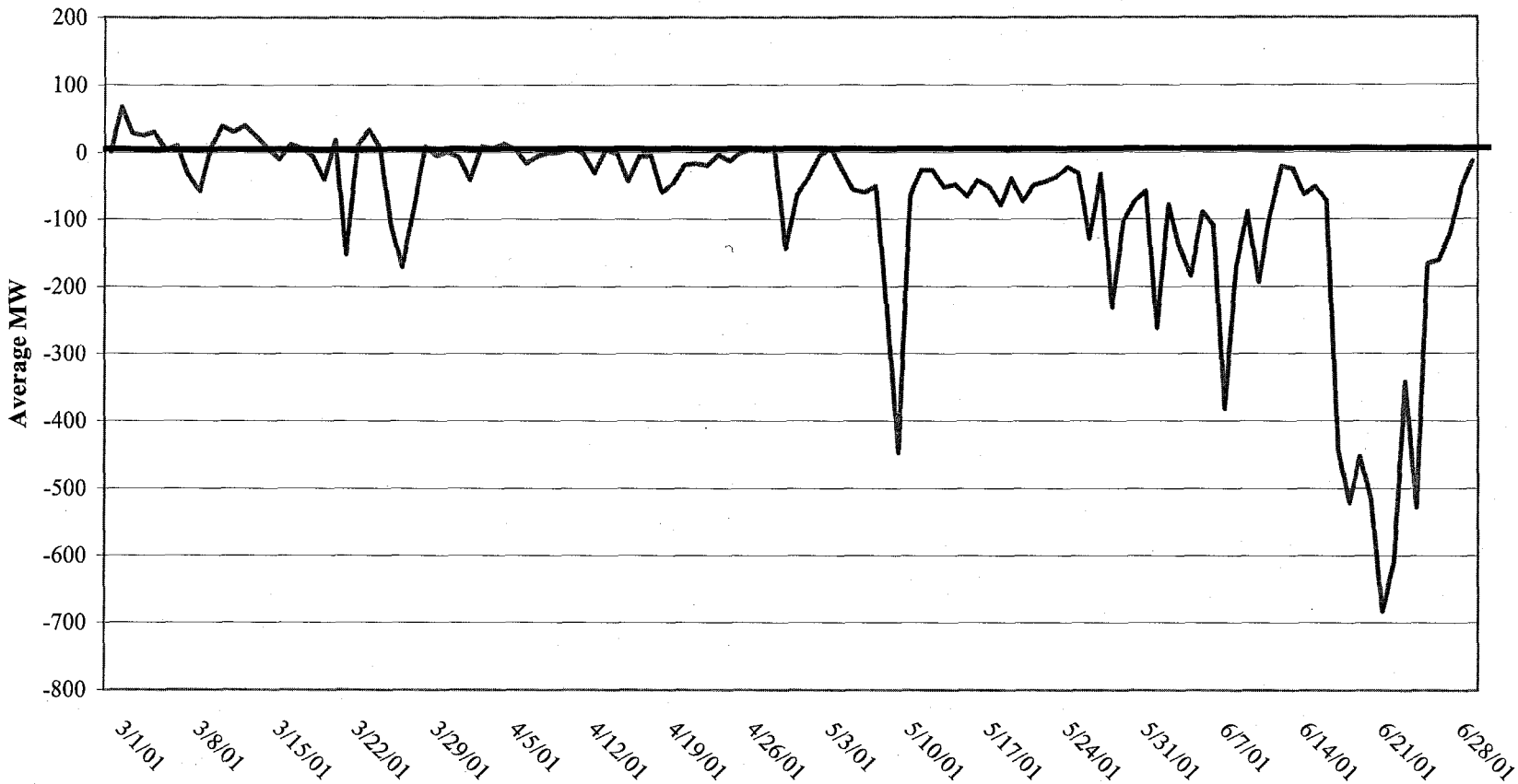
Figure J-5
Potential "Self Help"
by Duke Energy Trading and Marketing
March 2001 - June 2001



Notes & Sources: Amounts Owed from CAISO Certfication Data; Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

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Figure J-6
Uninstructed Deviations (All Hours)
by Southern Company Energy Marketing, L.P.
March 2001 - June 2001



Source: Uninstructed Deviations calculated by *The Brattle Group* (see work papers).

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Table K-1
Comparison Between Prices Reported by CAISO and Prices Reported by Reliant

			Q2, 2000	Q3, 2000
Max Price reported by Reliant for daily sales to ISO	[1]	See note	$290.63	$261.89
Hourly Prices Reported by ISO				
No. of Hours in which hourly price obtained exceeds Reliant's reported price	[2]	See note	102	133
Max hourly price obtained by Reliant ($/MWh)	[3]	See note	750	500
Daily-Average of Prices Reported by ISO				
No. of Days in which daily average price obtained exceeds Reliant's reported price	[4]	See note	15	15
Date of Max daily average price obtained by Reliant	[5]	See note	14-Jun-00	31-Jul-00
Max daily average price obtained by Reliant ($/MWh)	[6]	See note	679	464

[1]: Reliant's Second Quarter 2000 and Third Quarter 2000 Transaction Reports submitted to FERC. Reported prices refer to SoCal delivery point.
[2]-[6]: Sources are files CAL_ISO_1_Engy_00Q2.csv and CAL_ISO_1_Engy_00Q3.csv submitted as part of California ISO Responses to Data Request CAL-ISO-1. Prices are for delivery to SP15. Only includes hours during which Reliant sold energy to the ISO.
[4]-[6]: Daily-averaged prices are weighted by volume of Reliant sales to the ISO.