UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant,	)	**Docket Nos. EL00-95-000**
	)	**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 California Independent System Operator and the California Power Exchange	)	**EL00-98-000**
	)	**EL00-98-042**
	)	**EL00-98-063**

PREPARED TESTIMONY OF DR. GARY A. STERN ON BEHALF OF THE CALIFORNIA PARTIES

Index of Relevant Material Template

Submitter (Party Name)	California Parties
Index Exh. No.	CA-3
Privileged Info (Yes/No)	Yes
Document Title	Prepared Testimony of Dr. Gary A. Stern on Behalf of the California Parties
Document Author	Dr. Gary A. Stern
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	Sellers withheld from the market. Seller withholding and other market manipulation, not buyer underscheduling, led to forced reliance on the Real-Time Market. Prices in the ISO and PX Spot Markets from October 2, 2000 to June 20, 2001 were unjust and unreasonable. Prices before October 2, 2000 were not consistent with Sellers' market-based rate tariffs and those of the ISO and PX.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001; c) after 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95 and EL00-98 (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	It was a huge reduction in the amount of energy that the sellers, as a group, made available to the PX markets that forced buyers to resort to the ISO real-time market to satisfy their load requirements. Far from experiencing buyer underschedulings, the PX markets, beginning in the summer of 2000, reflected deliberate "under offering" by sellers. The result was far higher prices for California customers than would have been the case had sellers not practiced physical and economic withholding, and engaged in a plethora of manipulative games. This withholding can not be attributed to "market fundamentals." Virtually all sellers withheld power from the PX Day-Ahead market during peak conditions as compared to non-peak conditions, and the

	evidence contradicts the contention that NOx permits or hydro conditions were causing supply shortfalls. By contrast, even if the buyers had been willing and able to pay the maximum price for every megawatt sold in the PX Day-Ahead market, the effect on supply in that market would have been minimal. Thus, the underscheduling problem was the result of seller market manipulation and nothing buyers could have done would have eliminated it. The California Parties current estimation of the magnitude of additional relief to which they are entitled, over and above the approximate $1.8 billion addressed in Judge Birchman's proposed findings, is almost $5.8 billion. The total relief would be over $7.5 billion.
Party/Parties performing any alleged manipulation	All Sellers

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

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**PREPARED TESTIMONY OF
DR. GARY A. STERN
ON BEHALF OF THE CALIFORNIA PARTIES**

INTRODUCTION

Q. Please state your name, employer, and business address.

A. My name is Gary A. Stern. I am employed by Southern California Edison Company ("SCE"). My business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. In what capacity are you employed by SCE?

A. Since 1997, I have been the Director of Market Monitoring and Analysis in SCE's Regulatory Policy and Affairs Department. I am responsible for monitoring the electricity markets to help assure their efficient operation.

Q. Please describe your education and professional qualifications.

A. I received a Bachelor of Arts degree in Mathematics and Economics in 1979 from the University of California at San Diego. I received a Master of Arts degree in Economics in 1981 and a Doctorate in Economics in 1984, both from the University of California at San Diego.

From 1981 to 1984, I worked as an econometrician on the research staff of Quantitative Economic Research, Inc.

I joined SCE in 1984 as a Market Analyst. My responsibilities included estimating the effects of various load management programs. In 1985, I began working in Generation Planning where I analyzed demand and supply options. In 1986, I assumed responsibility for production simulation modeling, reliability modeling, economy energy modeling, and various other resource planning activities. In 1995, I transferred to the Treasurer's Department. In February of 1997, I transferred to Regulatory Policies and Affairs and assumed my present position.

Q. How is your testimony organized?

A. In the first part of my testimony, dealing with underscheduling, I discuss the sellers' allegations that buyers caused many of the dislocations in the California markets by deliberately underscheduling in the PX markets. I show that in fact it was a huge reduction in the amount of energy that the sellers, as a group, made available to the PX markets that forced buyers to resort to the ISO real-time market to satisfy their load requirements. Far from experiencing buyer underscheduling, the PX markets, beginning in the summer of 2000, reflected deliberate "underoffering" by sellers. The result was far higher prices for California customers than would have been the case had sellers not practiced physical and economic withholding. By contrast, even if the buyers had been willing and able to pay the maximum price for every megawatt sold in the PX day-ahead market, the effect on supply in that market would have been minimal. Thus, the underscheduling problem was the result of seller market manipulating and nothing buyers could have done would have eliminated it.

In the second part of my testimony, I discuss the California Parties' estimation of the magnitude of additional relief to which they are entitled. We currently estimate the total amount of such additional relief (above the approximate $1.8 billion addressed in Judge Birchman's Proposed Findings) at almost $5.8 billion. The total relief would be over $7.5 billion.

THE UNDERSCHEDULING ISSUE

I. Introduction to Underscheduling Testimony

Q. What is load underscheduling?

A. Underscheduling is the pejorative term describing the situation in which less than 100% of a load-serving entity's demand has been met in the day-ahead or hour-ahead PX markets, thus requiring some of the entity's demand to be met through the ISO's real-time market.

II. Sellers' Position on Load Underscheduling

Q. What position have sellers taken in the public arena with regard to underscheduling?

A. In their public statements concerning the California electricity markets in 2000-2001, sellers of power have attempted to deflect attention from their own actions by accusing buyers of load underscheduling. It has been the sellers' contention that buyers artificially depressed prices through this practice, and that, to the extent their own behavior is found to have inflated prices, it was merely a responsive strategy they were forced to undertake to offset the deleterious effects of this buyer strategy.

Sellers first accused buyers – particularly Pacific Gas and Electric Company, Southern California Electric Company and San Diego Gas & Electric Company ("IOUs") – of underscheduling in the summer of 1998, when the ISO first complained that the magnitude of its real-time market was larger than it had anticipated, and larger than it wanted that market to be for the purposes of reliable system operations. The ISO initially assumed, and the sellers argued, that the excessive magnitude of the real-time market was due to strategic behavior by buyers, and that this behavior must be stopped. However, numerous evaluations of the market contradicted this theory, and efforts to modify market behavior, under the false presumption that buyers were to blame, backfired, resulting in ever growing real-time volumes.

Nevertheless, the sellers' refrain blaming load underscheduling only grew louder. Eventually, during the 2000-2001 electricity crisis, as will be described below, sellers' strategies to manipulate the market were cloaked in the guise of efforts to help the ISO "keep the lights on" while, allegedly, the buyers of power continued to underschedule.

The facts below demonstrate conclusively that the growth of real-time volumes in the ISO was not due to IOU buying strategies, but was the direct result of a wide variety of withholding strategies by sellers to increase prices in both the PX's markets, and the ISO's markets.

Q. What kind of evidence do you have that sellers' behavior, including withholding power from the PX day-ahead market, contributed to allegations of "underscheduling"?

A. I have found substantial evidence that sellers withheld power from the PX day-ahead market. This includes an examination of supply bidding behavior in the PX that is presented later in my testimony, as well as a discussion of the impact of various market manipulation strategies employed during the 2000-2001 period. One particularly clear example of such strategies, only recently made public, relates to Reliant's behavior in June of 2000. Reliant, whose physical and economic withholding behavior has already been proven to FERC through the transcripts released along with FERC's January 31, 2003 Stipulation with Reliant, has been the most egregious in its disinformation campaign. The trader transcripts provide clear evidence of Reliant's pre-meditated plan to manipulate not just the markets, but also those who would review their behavior in the markets. For example, the Reliant transcripts of June 20, 2000, describe a plan to blame Reliant's withholding of power on (1) a shortfall of emissions credits, and (2) a supposed need to maintain its reserve margins:

> Reliant Trader 2: "Buy dailies and then shut down all the plants…"

Followed immediately by:

> Reliant Trader 2: "And then that way we going to put out that we are short NOx, we're short capacity factor."[1]

The first statement clearly show Reliant's plan to shut down plants. This is followed by Reliant's plan to claim ("put out" refers to a plan to make statements to the market or in public forums) a shortage of NOx credits necessary to operate the plant (credits which can be purchased in the market, and thus only provide an economic signal, not an output restriction), and Reliant's plan to claim that it had concerns over its ability to meet daily obligations based on plant performance ("short capacity factor").

These internal discussions were followed by statements from John Stout of Reliant to the House Committee on Energy and Commerce on September 11, 2000 in which, in addition to claiming that Reliant had "a lot of units that are constrained in how much they operate due to air emission constraints" and arguing that Reliant would have taken too great a financial risk if it had sold too much of its power in the day-ahead market ("short capacity factor" as stated by the Trader quote above), he also misrepresented buyers' behavior and motives:

> To make matters worse, California buyers keep waiting to the last minute, the real time market, after the rest of the western market has locked up all the moderately priced power, to make their last 10,000 to 15,000 megawatts of purchases. As a result, they are left with the tail end of the supply curve. They know what prices to expect, and yet the market rules and their bidding strategies consistently put them last in line. It's true that sellers can sometimes name their price in such a situation, but only because imprudent buying practices give them that ability.[2]

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[1] Exh. No. CA-52 at 25.

[2] Exh. No. CA-228 at 2.

In other words, Mr. Stout repeated what he had been telling the ISO, that the problems in the market were the result of imprudent buyer underscheduling of load. Of course, Mr. Stout did not mention to Congress Reliant's withholding behavior.

After having spent the better part of a year blaming the utilities for not buying in the day-ahead market as prices rose, and instead purchasing to meet some of their load in the ISO's real time market, on April 12, 2001, Mr. Stout accused the buyers of causing prices to rise by paying *too much* in the day-ahead market. He testified at joint hearings before the House Committee on Government Reform and the Subcommittee on Energy Natural Resources and Regulatory Policy, as follows:

> So why did the market clear at $750 a megawatthour? . . .
> Because the buyers raised their bid prices.[3]

He added:

> And let me close by explaining why this takes place . . . . Because this is a competitive auction, but the competition, because you had a shortage of supply, was existing between buyers, not as much between suppliers.[4]

In a similar presentation Reliant made to the ISO Board at which I was present, Mr. Stout claimed, in the same 180-degree turn from the original underscheduling complaints, that the buyers were trying to raise prices in the market through this buying behavior. It is interesting to note that in the last phrase of the quote above, Mr. Stout is acknowledging the absence of competition among sellers – the touchstone of market power.

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[3] *Id.* at 4.

[4] *Id.* at 5.

Despite the lack of credibility that these accusations of underscheduling and demand bidding should have had, considering the market circumstances, this campaign was successful at diverting the full attention of those investigating the market from the manipulative behavior of the sellers to the bidding practices of the buyers. It is important that the facts surrounding demand bidding and underscheduling be presented so that the new attempts at this misdirection strategy are seen for what they are.

III. Supply Bidding Into The PX Day-Ahead Market

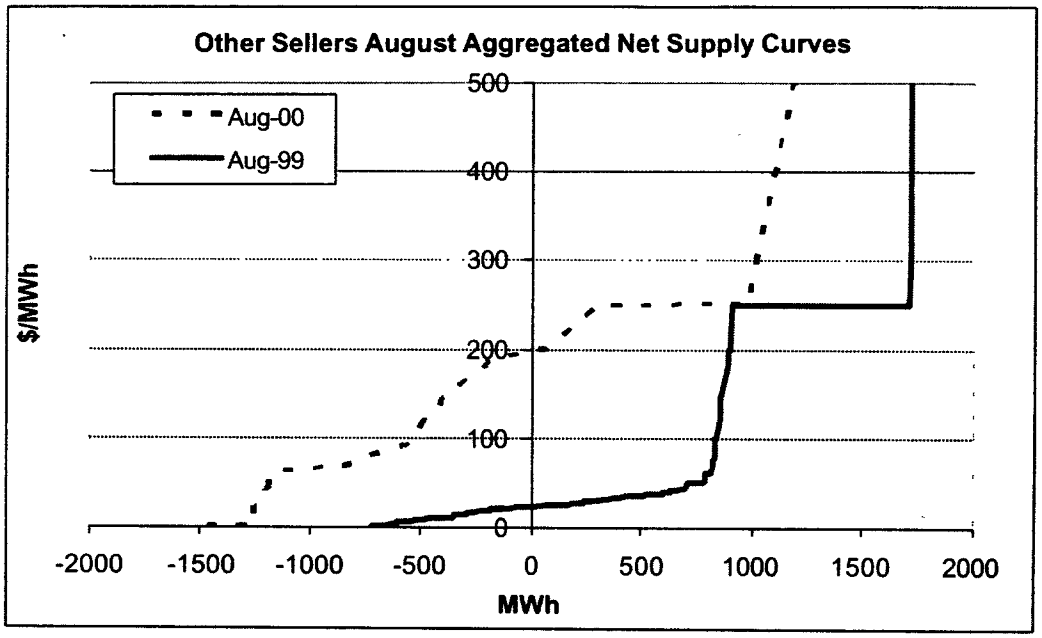
Q. Can you describe sellers' bidding behavior?

A. Despite many statements by sellers claiming that load underscheduling in the PX day-ahead market contributed to the energy crisis, and that their own strategies were merely creative attempts to help the ISO in response to load underscheduling, the facts will show that supply withdrawal from the day-ahead market was the real cause of underscheduling. In an effort to systematically evaluate the supply bidding behavior of sellers into the PX day-ahead market, I performed a supplier specific analysis of bidding.

Q. What methodology did you use?

A. I aggregated PX day-ahead bid curves for a specific hour over the weekdays in each month from May 1999 through September 1999 and also between May 2000 and September 2000. For each entity examined I first established a net supply curve by subtracting its bids to buy power from its bids to sell power. I then averaged each of the net supply curves for each entity for hour ending 16 for each of the weekdays for the month. I then examined the data using a monthly comparison of aggregate net supply curves between 1999 and 2000. I chose a subset of the sellers to examine that included

Duke, Dynegy, Enron, MIECO, Mirant, Powerex, Reliant, and Williams. I separated the IOU buyers and municipal buyers from the remaining group, and constructed an aggregated "Other Sellers" category to capture the remaining selling entities. For example, shown below is the aggregate supply curve comparison for the "Other Sellers" for August of 1999 and 2000.



Q. What do you conclude from this?

A. As is evident from this example, the aggregate set of Other Sellers offered for sale, on average, significantly less power to the PX day-ahead market in 2000 compared to 1999. This approximate loss of 700-1,000 MW of supply from these sellers is an example of the loss of access to resources that resulted in the IOU PX buyers being forced to acquire power in the ISO real-time market. As my further analysis of this supply bidding data discussed below demonstrates, there was a systematic withdrawal of supply from the PX day-ahead market adding up to thousands of MW. This behavior can be attributed to most of the selling entities examined, with some exceptions.

The supply offers to the PX day-ahead market determine the amount of capacity that is available for buyers to acquire on a day-ahead basis. If the sellers don't offer enough power for purchase (physical withholding), the buyers will be forced to meet some of their load in the ISO's real-time market. If the sellers offer some of their power, but at excessive prices (economic withholding), then buyers effectively have to choose between either meeting their demand in the day-ahead market at unreasonable prices, or taking their chances for some portion of their load in the ISO's real-time market. As the net supply curve data clearly shows, both physical and economic withholding in the PX day-ahead market was the standard for sellers (again, with noted exceptions).

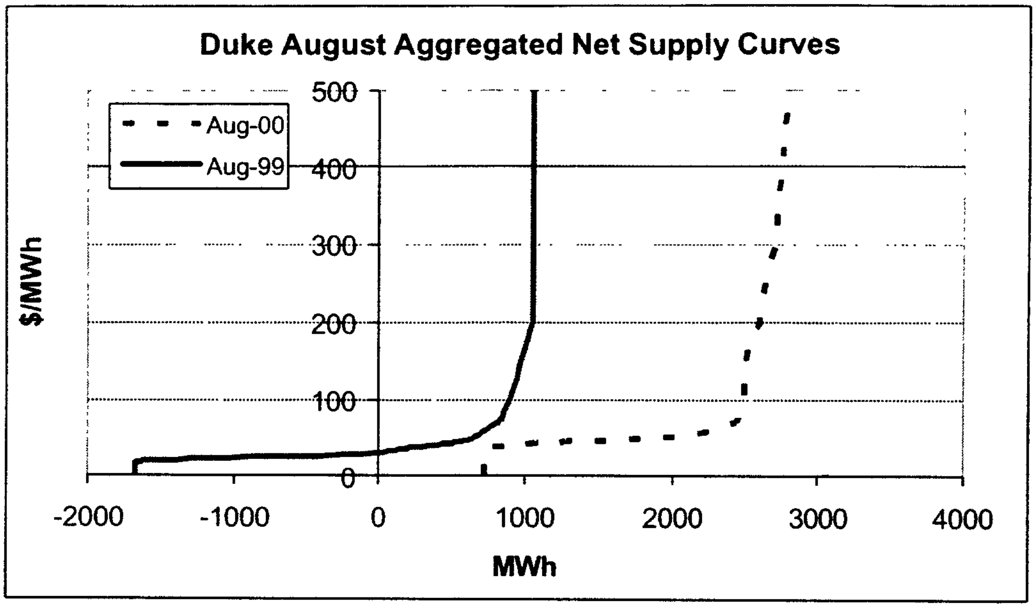
Each seller's supply bidding behavior is summarized below.

A. Duke

Q. What did you find in your analysis of Duke's bidding behavior?

A. Duke was a large seller into the PX Block Forward market (BFM) and typically made low-priced bids (consistent with marginal operating cost) into the PX day-ahead market with volumes corresponding to its BFM volumes. The PX BFM did not even exist until July of 1999, so these sales were predominantly in 2000. Perhaps Duke had bilateral sales outside the PX in 1999, I do not know. I do know that Duke sold significantly more power into the PX day-ahead market during the May to September period in 2000 than in 1999. However, despite Duke's increases in sales, the sellers overall offered, net of their own purchasing, considerably less power in 2000 than in 1999, as can be seen in the monthly summary graph below in the discussion of all sellers.

Duke's increased offering of power into the PX day-ahead market in the period from May to September of 2000 generally coincides with Duke's BFM sales. The price at which Duke offered power into the PX day-ahead market, for a large portion of the power offered, seems consistent with the explanation that Duke has advanced, namely that its behavior was largely governed by its forward commitments, including its BFM sales. For bilateral forward sales, Duke had the incentive to generate from its plants if the market price for power were above its incremental production cost. During low-market-priced periods, its profits could be increased by shutting down its plants and buying out of the PX day-ahead market to fulfill its obligations when its production costs exceeded the market price. This is consistent with its 1999 bidding pattern. When Duke's forward commitments were through the BFM, then its incentive would be to bid a corresponding volume of power into the PX to hedge its price position, at its marginal cost of production. If the clearing price exceeded its cost of production, then it would be producing from its plants, and it would have locked in its BFM price for those PX deliveries. By bidding marginal cost of production, at such times as the market clearing price were below Duke's bid, Duke would not have its schedule awarded, and its BFM position would be met through PX purchases from others, per the BFM settlement rules, so that its profits from BFM sales could actually be increased by Duke's avoidance of production costs. Again, Duke's 2000 bidding pattern appears to track its statements regarding its forward position, and its incentives, for that portion of its portfolio under forward contract. The Duke aggregated net supply curve for August is shown below.



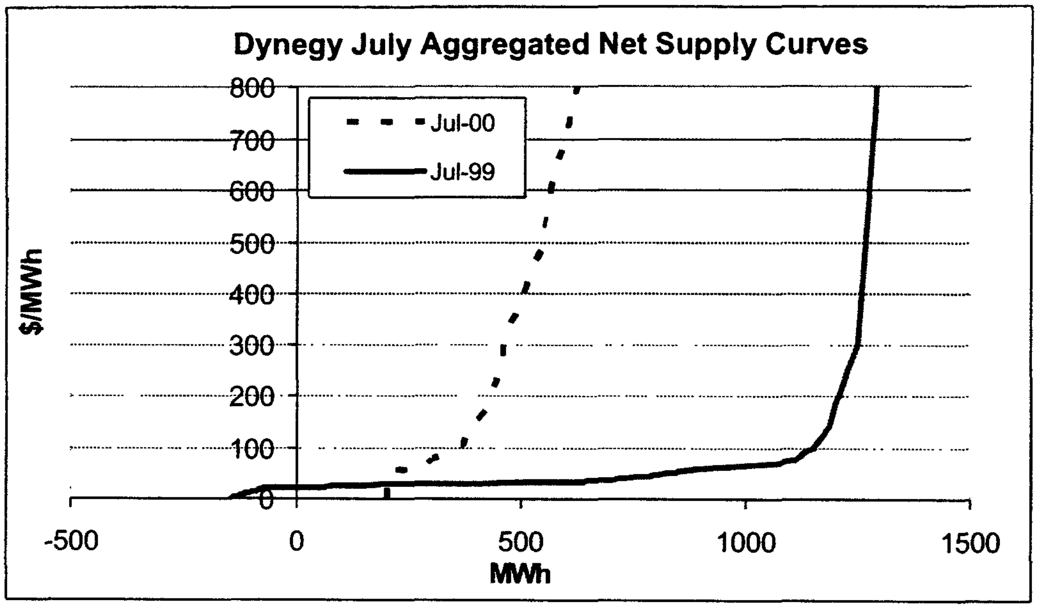
The pattern of Duke's increased offering to the PX did not vary much among months, though the magnitude of Duke's increased offers peaked in June and July 2000 at about 2,000 MW of increased power for sale in the PX day-ahead market.

It is worth noting that Duke's strategy for that part of its portfolio not hedged in the BFM appears to differ from the aforementioned marginal-cost-based approach. For large levels of output, for example, 2,500 MW for August of 2000, Duke may have been long in the spot market. Duke's bids above this level of output follow the hockey stick pattern as they rise from bids around $60 for output around 2,500 MW to bids between $150 and $500 for output between 2,600 and 2,700 MW.

A. Dynegy

Q. What did you find in your analysis of Dynegy's bidding behavior?

A. Compared to Duke, Dynegy's PX net supply offering pattern was more typical of sellers in the PX market. In 1999 Dynegy offered a substantial portion, as much as 1,000 MW of its portfolio, into the PX market on a day-ahead basis. In 2000, Dynegy substantially reduced its offers into the PX day-ahead market. Consider the July net supply curve from Dynegy, below.

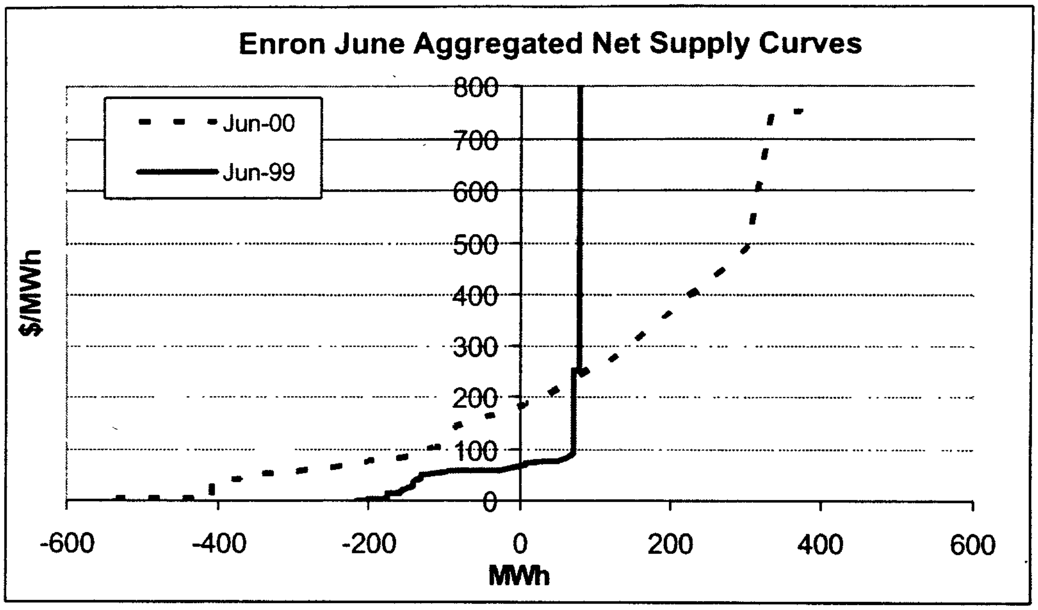


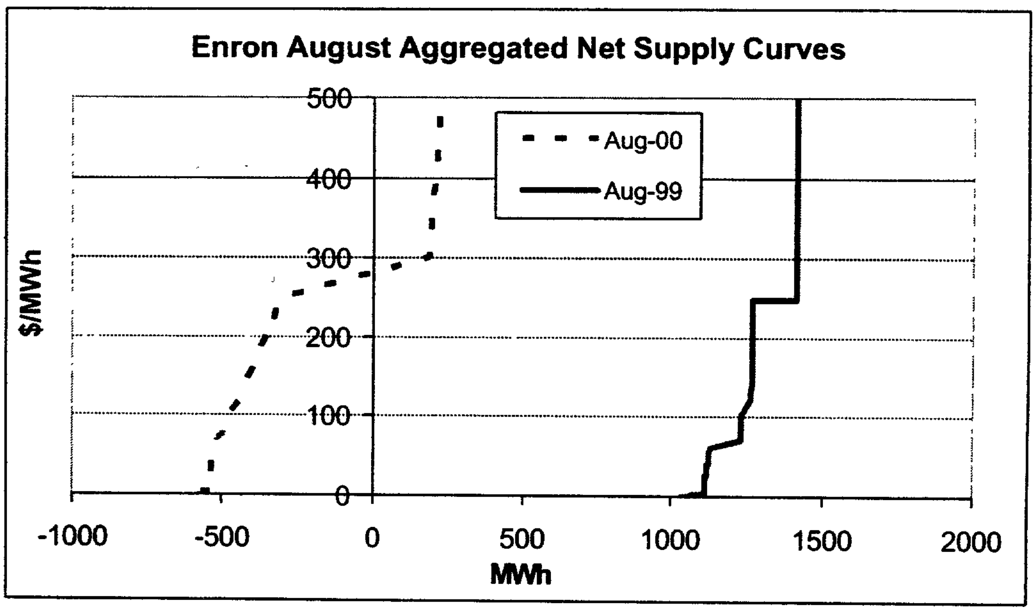
Dynegy offers declined from about 1,200 MW in July of 1999 to less than 500 MW in July of 2000. An examination of Dynegy's behavior in the ISO's real-time market may reveal information regarding some of the reasons for Dynegy's withdrawal of power from the PX market. Regardless of Dynegy's reason for withdrawal, the absence of their power exacerbated the buyers' inability to acquire sufficient day-ahead power through the PX to meet their forecasted demands.

B. Enron

Q. What did you find in your analysis of Enron's bidding behavior?

A. Enron did not own significant generation with which it could participate in the energy markets. It did acquire a portfolio of power through purchases contracts with others, however. In August and September of 1999, Enron offered significant amounts of power for sale into the PX market. Those levels exceeded 1,000 MW. From May through July, Enron offered much less power into the PX in 1999, and in fact, at low prices; it was more interested in buying than selling in the PX day-ahead market, based on its net supply bids (negative at low prices, indicating net buy offers). In 2000, Enron was consistently more interested in buying from the PX than selling into it, unless very high prices were reached. The result is that comparing 1999 to 2000 for Enron, we see that during the May through July period, Enron offered more into the PX market in 2000 than 1999 at high prices, though they sought to purchase more from the PX in 2000 at low prices. By August and September of 2000, Enron simply offered to buy modest levels of power (a few hundred MW) at prices below $250/MWh, and offered to sell at prices exceeding that level. This was in sharp contract to the offers to sell in excess of 1,000 MW during August and September of 1999. June and August graphs illustrate these patterns below.



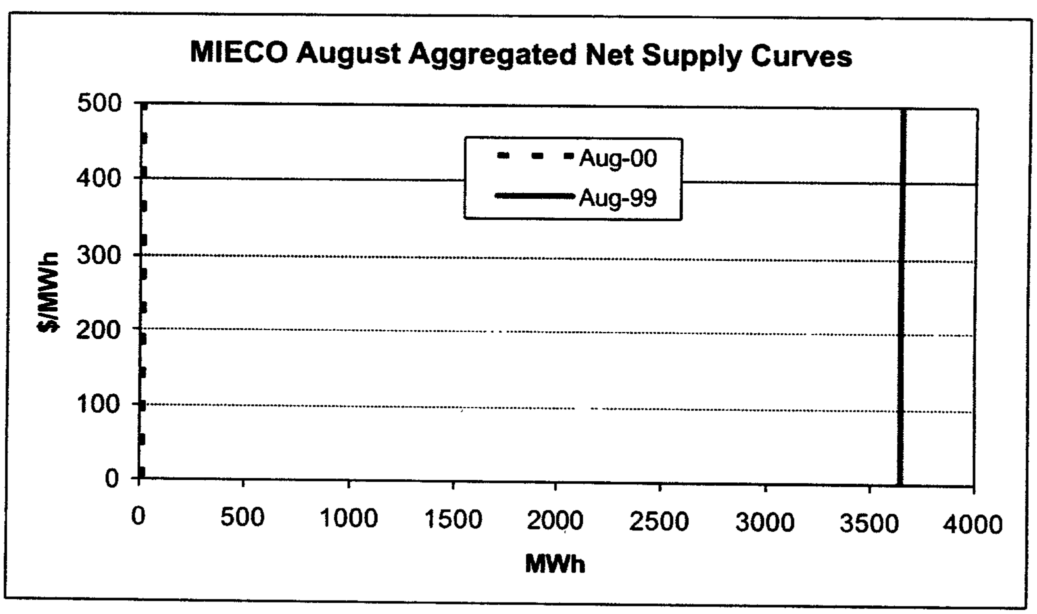


C. MIECO

Q. What did you find in your analysis of MIECO's bidding behavior?

A. MIECO is an energy trader that does not own physical assets but has acquired positions in the market through forward purchases, and, at least in 1999, used the PX day-ahead market as an avenue for selling its acquired power. Comparison of the August 1999 and 2000 supply bid curves for MIECO reveals a stark difference in position. MIECO bid its power essentially as a price taker, so the shape of the supply curve reveals no evidence of unusual bidding behavior. The magnitude of the power that MIECO sold through the PX in 1999 was remarkable. The average amount of power offered by MIECO during August of 1999 was about 3,700 MW. The maximum amount offered by MIECO was 4,250 MW. Similar levels of power were offered for sale in July of 1999. These levels of power sales are roughly sufficient to meet the needs of San Diego, the sixth most populous city in the country. Although this occurred in July and August of 1999, the fact that an entity was able to acquire such a position without any attention from FERC or the market monitors suggests serious flaws existed in the monitoring system, and perhaps the market based rate authority rules.

The graph below shows MIECO's offers for August of 1999 and 2000.

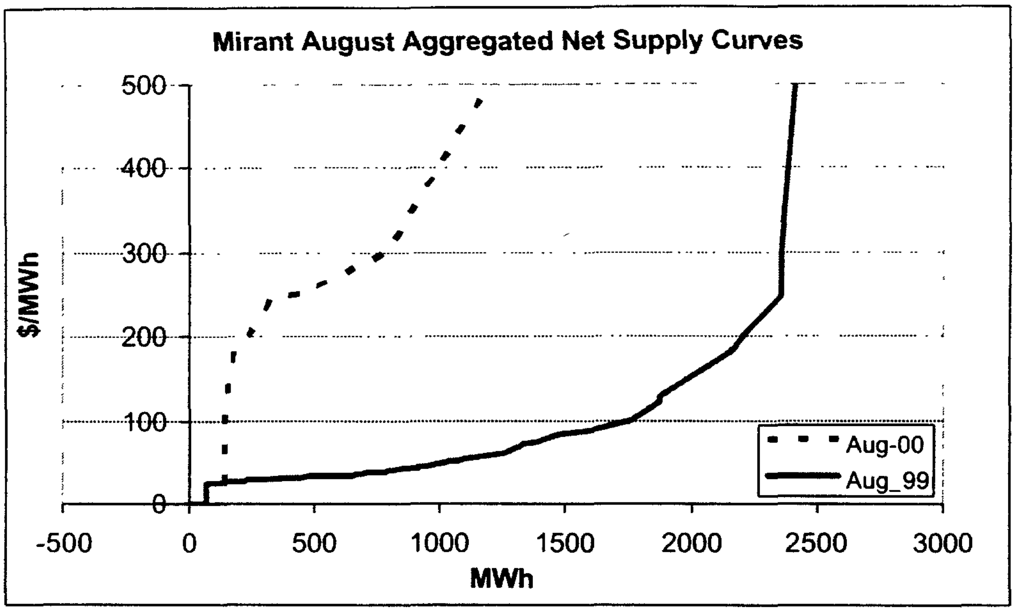


MIECO, for all intents and purposes, did not offer power to the PX in 2000. The loss of available power to buyers in the PX from the departure of MIECO was tremendous: while MIECO provided roughly enough power to serve all of SDG&E's load in 1999, they were out of the market in 2000. No new party stepped into the role vacated by MIECO, with the result that there was simply much less power offered in to the PX day-ahead market in 2000 for IOU buyers to acquire to meet their needs. Withdrawals like this explain why underscheduling occurred: power not offered could not be bought.

D. Mirant

Q. What did you find in your analysis of Mirant's bidding behavior?

A. Mirant is another seller that for most of the months examined showed a somewhat typical pattern of bidding behavior. It offered substantial levels of power into the PX day-ahead market in 1999, reaching averages approaching 2,500 MW in August, as can be seen in the graph below.



Those substantial offerings in 1999 mostly disappeared in 2000, with less than 300 MW offered at prices below $250/MWh on average. The loss of roughly 2,000 MW from Mirant in August, along with similar patterns of reduced offerings by other sellers more than makes up for the additional power offered by Duke. With sellers such as Mirant offering so much less power for sale into the PX day-ahead market, buyers could not successfully acquire sufficient power to meet their forecast demand day-ahead, and were forced to use the ISO's real time market.

It should be noted that Mirant's pattern of offering substantially less in 2000 did not begin until June of 2000. During May of 2000 Mirant offered close to 800 MW more on average than it had in 1999. Unfortunately for buyers, by June Mirant had reversed that pattern.

E. **Powerex**

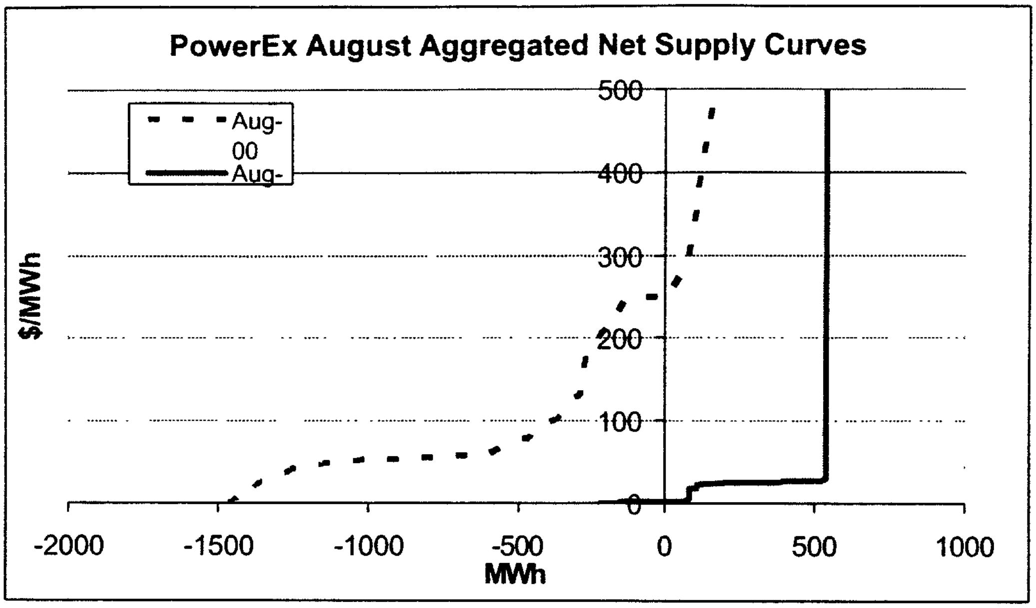
Q. What did you find in your analysis of Powerex's bidding behavior?

A. The withholding of power by an individual entity from the PX market could be the result of one of several causes. For some, such as Powerex whose sources of power include hydro from its parent, BC Hydro, it is possible that reduced availability of power can explain reduced offers to the PX day-ahead market. However, the increased level of sales into the ISO real-time market through "over-scheduling" games such as Fat Boy, belie this explanation in Powerex's case.

Powerex changed from being a seller of day-ahead power in 1999 to a buyer of day-ahead power by August of 2000. In light of Dr. Berry's testimony, it seems likely that Powerex was acquiring power from the PX for resale into the ISO real-time market, a market into which it also submitted "price support" buy bids. Powerex's speculative strategy between the PX day-ahead market and the ISO's real time market, accompanied with some price manipulation bids into the ISO's real-time market to increase the chances of profit, formed a repeated pattern of market abuse. One element of collateral damage from this market abuse was reduced accessibility of power to buyers in the PX day-ahead market. Powerex recognized that its efforts to drive up prices in the real-time market would draw other supply to real time in an internal e-mail.[5]

Powerex's August net supply curves for 1999 and 2000 are shown in the graph below.

[5] *See* Exh. No. CA-176 at 296.



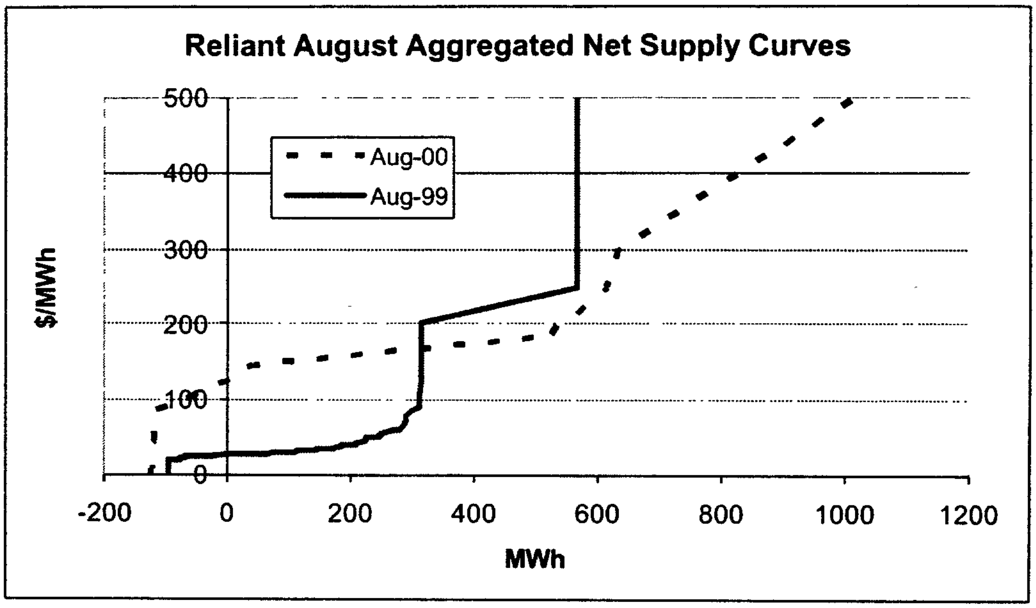
Prior to August of 2000, Powerex was offering to sell a fair amount of power (500-700 MW) into the PX day-ahead market, though by July these offers were only available at three digit prices. There was still a substantial difference between 1999 and 2000 patterns for Powerex in terms of the volume offered for sale/purchase. But by August of 2000, there were essentially no offers to sell into the PX day-ahead market by Powerex at all, below the ISO cap.

F. Reliant

Q. What did you find in your analysis of Reliant's bidding behavior?

A. Unlike some of the other participants, Reliant's PX offering pattern was not particularly constant over time. In May of 2000 Reliant offered substantially the same amount of power into the PX as in May of 1999, at levels reaching about 500 MW, most of which appears to be at its marginal costs. However, in June of 1999 Reliant increased its level of offers into the PX substantially compared to May 1999, with magnitudes exceeding

800 MW. By contrast, in 2000, Reliant's reduced its offers by about 100 MW between May and June. For July, Reliant's net supply curve did not differ substantially between 1999 and 2000. In August and September 2000, we see Reliant offering substantially less into the PX day-ahead market at low prices than it did in 1999, but offering more at high prices. The August graph below exemplifies this pattern.



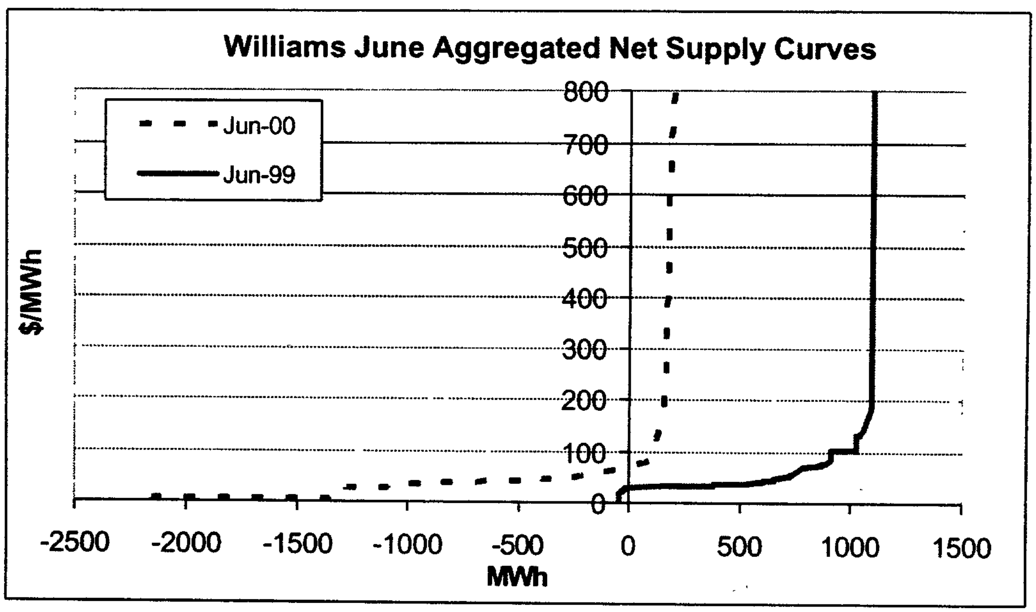
Although Reliant's supply curve shows a willingness to sell more power in 2000 than it offered in 1999 in the PX day-ahead market, those increased offers occur at very high prices, including several hundred MW offered at prices that were higher than the ISO's $250 price cap put in place on August 8, 2000. If buyers purchased at these excessive prices they would have been paying well above what they would have paid for energy in the ISO's market. Such buying behavior would have been nonsensical for IOUs to undertake. High-priced sell offers such as these allowed Reliant to complain about buying behavior in the PX, alleging that because there were times when their supra-ISO cap offers were not accepted by IOU buyers, those buyers must be underscheduling their load. We now know that Reliant was withholding power from the PX to increase PX spot and thus forward prices, it was bidding to buy power from the PX day-ahead market to attempt to raise prices, and it was misrepresenting its behavior to the ISO, the FERC and Congress. Later I will examine what the financial and operational impacts would have been of falling for this Reliant trap, in an individual hour I studied with regards to SCE in particular, and for the whole summer for all the IOUs. As I will show, if IOUs had agreed to pay exorbitant prices based on this, in the PX, the underscheduling problem would have persisted but prices would have skyrocketed even further.

As Dr. Carolyn Berry examines in her testimony, Reliant has been shown to having intentionally having withheld power from the PX in a "market power play" to increase market prices. The Reliant Settlement with FERC covers Reliant's supply withholding on June 21-22, 2000. In fact, Reliant also submitted demand bids on this date, an action they had not previously taken during the relevant period under examination. This demand bidding action was another tool used by Reliant to increase PX day-ahead prices, consistent with their stated purpose of raising forward prices. It should be noted that Reliant also used this demand bidding strategy on July 19 and 20, 2000. On those dates, Reliant submitted price taker bids to buy power during the on-peak period, in the amounts of 400 MWs on July 19, and 922 MW on July, 20. This behavior is captured in my analysis through the examination of net supply curves.

G. Williams

Q. What did you find in your analysis of Williams' bidding behavior?

A. Williams followed a pattern of offering substantially more power into the PX day-ahead market in May and somewhat less in June and July. In all summer months, if Williams was offering power at all, it offered substantially less in 2000 than it had in 1999. By August 2000, as had been the case in 1999, Williams became a net buyer in the PX day-ahead market based on its aggregate net supply curve. By September 2000, the more typical pattern of reduced offers in 2000 returned. The graph below shows June, the month in which Williams' offers to sell into the PX day-ahead market dropped most significantly.

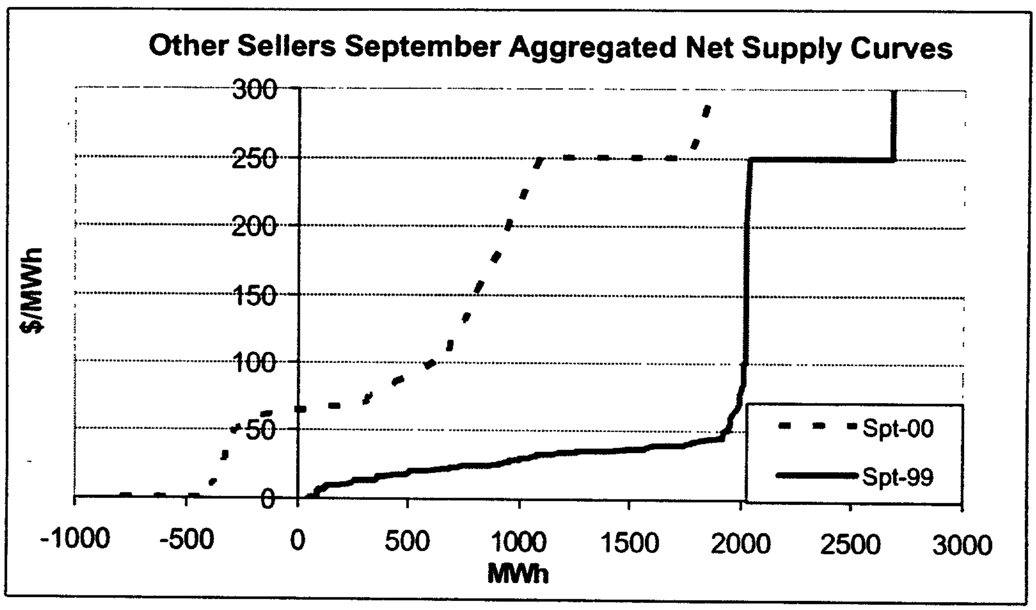


H. Other Sellers

Q. What did you find in your analysis of the "Other Sellers" bidding behavior?

A. The "Other Sellers" category captures the aggregate net supply bid of the remaining PX participants, excluding the three California IOUs. An examination of the Other Sellers' supply bids comparing corresponding months in 1999 and 2000 shows a reduction in the amount of power offered to the PX. The amount varies some by price level but is on the order of 1,000 MW. There are a number of plausible explanations for the reduction in power offered. Regardless of the reason for the reduction, the fact that less power was offered to the PX day-ahead market unequivocally means that there was less power available for buyers to purchase day-ahead from the PX.

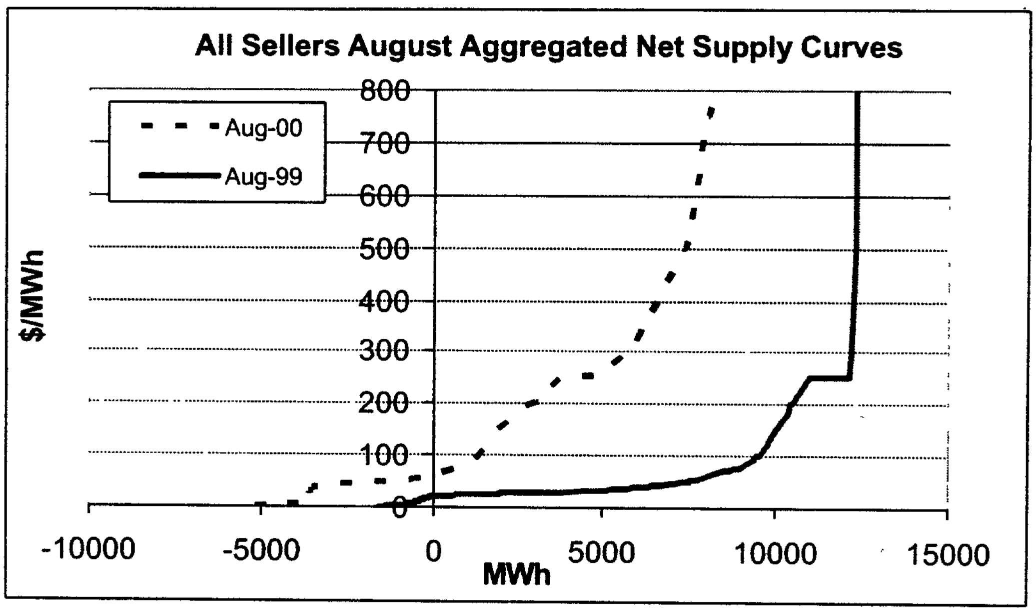
The Other Sellers category demonstrates the typical pattern of reduced 2000 offers into the PX day-ahead market as shown in the September graph below.



I. All Sellers

Q. What did you find in your analysis overall of sellers' bidding behavior?

A. Aggregating all of the individual sellers listed above, plus the Other Sellers category, the graphs below show in total the offering behavior of all sellers into the PX day-ahead market. During May 2000, there was still no appreciable difference in the quantity of power offered into the PX day-ahead market compared to the corresponding month in 1999. By June, a gap of approximately 2,000 MW emerged, with less power being offered in 2000 than 1999. In July, that gap grew to about 6,000 MW. In August the gap grew again, reaching about an 8,000 MW reduction in supply offered to the PX day-ahead market. The August graph is shown below.



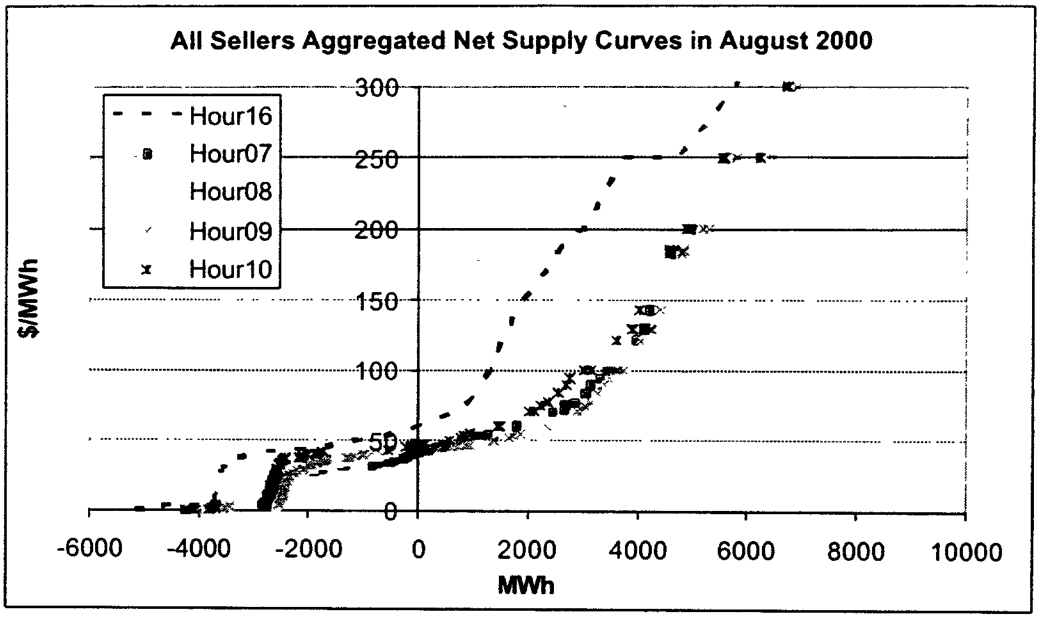
In September 2000, the gap still approached 6,000 MW. In summary, there was such a substantial reduction in the quantity of power offered by sellers into the PX day-ahead market, beginning in June of 2000, that the IOU buyers in the PX day-ahead market lost the ability to procure sufficient power to meet their forecast demand. To the extent large real time market volumes developed, that underscheduling cannot be attributed to load, since load simply could not buy what was not offered in the PX day-ahead market. Later I will examine scenarios demonstrating that changes in supply bid prices, for the same quantities that were offered, could have helped ameliorate the underscheduling problems. I will also show that changes in demand bidding could not have substantially reduced the level of underscheduling that occurred, for reasons that should now be obvious from the sellers' net supply curves. Changes in demand bidding behavior could have added billions in costs to the California consumers without any additional reliability benefit, which would have resulted in billions of additional profits for sellers. This may also explain why sellers lobbied so vociferously for actions to prevent buyers from considering price in their PX day-ahead bidding at all.

J. Sellers' Withdrawal of Supply During Peak Hours

Q. Did sellers behave differently during peak hours compared to other hours?

A. As I have shown, sellers withdrew tremendous amounts of supply from their PX day-ahead market offers in 2000 as compared with 1999. This withdrawal was the proximate cause for the inability of buyers to acquire sufficient supply to meet their load in advance of the ISO real-time market. In order to determine whether this withdrawal was related to availability of supply, I asked the following two questions of the data: (1) was more supply made available during the peak afternoon hours, consistent with limitations on power availability for either run hours or hydro conditions; and (2) was less power made available in September, consistent with potential environmental constraints or water supply. If these conditions were true, we could conclude that some of the supply withdrawal from the PX may have been due to fundamental conditions.

The graph below looks at the net supply offered in August, for all sellers, during the morning hours ending 7, 8, 9, and 10 and during the afternoon peak hour ending 16.



This graph clearly shows that about 2,000 fewer MW were offered to the PX day-ahead market in the afternoon – during peak conditions – than were made available during the morning hours. This withdrawal of afternoon power cannot be explained by forward or bilateral contracting, as standard contracts encompass hours 7-22. This pattern is consistent with intentional withholding of supply during tight conditions – a clear exercise of market power by sellers. The fact that less power was offered during the high load afternoon period, when prices were also consistently higher than the early morning hours, is a clear indication of intentional withholding from the PX day-ahead market. Examination of the ISO's May-June, 2000 Report on Energy Market Issues and Performance, dated August 10, 2000, shows that the underscheduling observed by the

ISO is highly correlated with this change in supply offering between morning and afternoon hours. In that report the ISO states on page 25:

> Recent PX market prices and volumes – as well as sample aggregate supply and demand curves released by the PX – indicate that despite recent "shifts" in aggregate demand (reflecting an increased willingness-to-pay in the forward markets), the ability of buyers to increase purchases in the PX Day Ahead markets is severely limited by the nearly vertical slope of the PX supply curve around the 30,000 MW level.[6]

This is just one additional strong piece of evidence demonstrating that it was supply withdrawal that caused underscheduling, a conclusion that the ISO report supports.

I anticipate that sellers will point to actions and statements by ISO management to stop buyers from underscheduling.[7] Such actions and statements were not even consistent with the ISO's own contemporaneous assessment of underscheduling, as evidenced by the ISO May-June report, let alone consistent with the facts.

Q. Did sellers behave differently over time, based on fundamentals in the market?

A. The graph below illustrates the net supply offered to the PX day-ahead market during the afternoon (hour 16) during the months of August and September.

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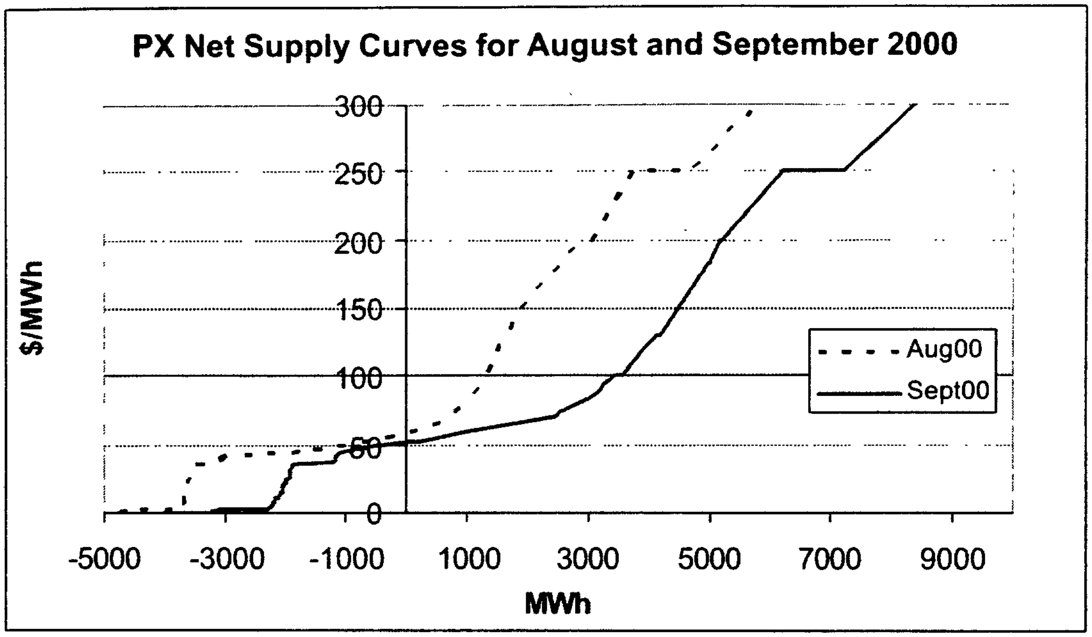
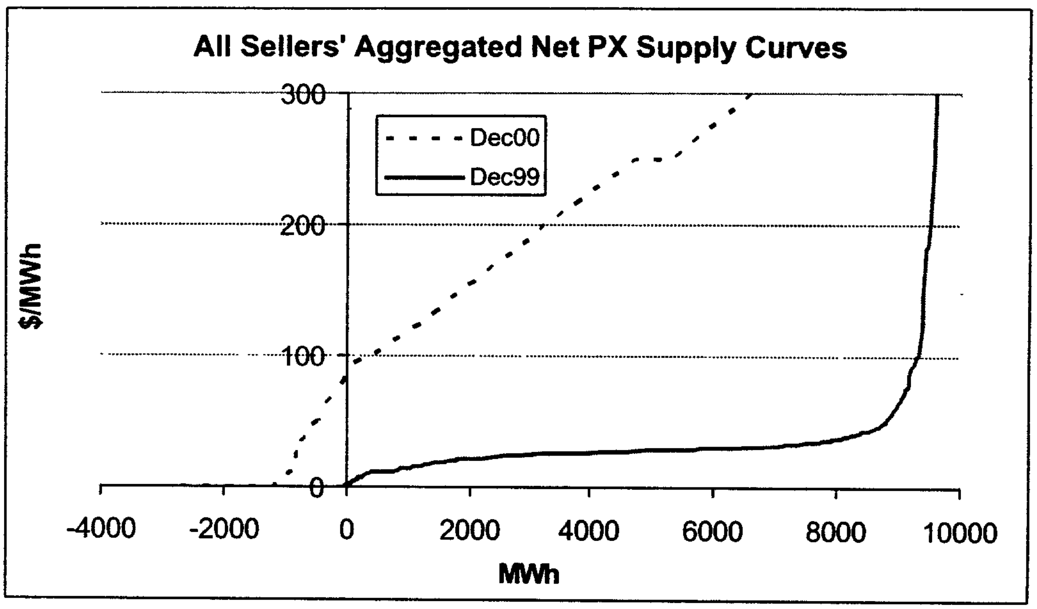
[6] Exh. No. CA-231 at 2.

[7] *See* Exh. No. CA-241 (memorandum from Terry Winter, President and CEO of the ISO, to the ISO Board of Governors (August 25, 2000)).



As this graph demonstrates, as much as 3,000 MW more power was made available in September than in August. Again, this directly contradicts the contention that NOx permits or hydro conditions were causing supply shortfalls, as these conditions would lead to fewer hours of available supply in September compared to August. The data show the converse to be true and are consistent with the systematic withholding of power by sellers, clear evidence of the exercise of market power.

I analyzed May through September 2000 in detail to focus on the period before the refund effective date established by the Commission, in order to understand seller behavior in that period. The trends that I have described for the summer of 2000 likewise appear later in 2000, though the numbers in the summer and winter period are difficult to compare because of differences in the total demand level in both periods. Also, there was some transitioning in behavior. For example, as I described above, by the end of the summer Powerex had moved from offering a small amount of supply to the day-ahead market at high prices, to a net buyer. By December 2000, this behavior was firmly entrenched, and Powerex was withdrawing at times 1,000 MWh or more each hour from the market – driving up the day-ahead prices and making it even less feasible for the IOUs to satisfy their needs in the PX Day-ahead market. Of course, the power did eventually show up for the IOUs, but in the real-time market or in high-priced OOM purchases. The graph of hour 16 during December 1999 and 2000 below demonstrates the continued withdrawal of power from the PX by suppliers.



At prices in the $100-$200 range there were 6,000 to 9,000 MW withdrawn from the supply offers. High natural gas prices during 2000 explain the low-price end of this result, but even at prices as high as $300, above the marginal cost of production, there remained an average gap of 3,000 MW. These gaps must be considered in light of the lower loads during the winter period.

The data previously discussed identify which sellers were withholding from the PX day-ahead market. These data eliminate the possibility that fundamentals can explain the withdrawal of power from the PX day-ahead market. What we have left is the inevitable conclusion that sellers intentionally withheld power to drive up prices in the market. One entity, Reliant, has already clearly admitted to such practices as reflected on the tape transcripts made public by FERC as part of the January 31, 2003 Stipulated Agreement. Supply withholding made the purchase of adequate power by demand-serving IOUs impossible. Underscheduling was caused by suppliers, not by buyers.

IV. The Myth of Load Underscheduling

Q. Can you explain how underscheduling occurs?

A. As I show in this testimony, so-called underscheduling is due to a combination of factors, including the supply withholding behavior just described, and including the now notorious practices of generators and marketers of power described in the internal memos from Enron Corporation and many other places, and used by many participants as described in Dr. Fox-Penner's testimony. In order to gain a better understanding of underscheduling, one must understand the basic operation of the PX and ISO markets.[8]

A. A Brief Description of the Operation of the PX and ISO Markets

Q. Plaese describe the basic operations of the PX and ISO markets.

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[8] Due to the collapse of the wholesale electricity market caused by California's energy crisis, the PX ceased operating its market on February 1, 2001. This section of the testimony will describe the operation of the PX and ISO markets, the actual bidding behavior of the IOUs, and the views of the independent monitoring organizations on underscheduling.

A. The PX operated a day-ahead market in which bids were submitted by 7:00 a.m. on Day One for the 24-hour delivery period from midnight to midnight on Day Two. Bids for buying the quantity one desired at a specified price were submitted in price pairs. At one extreme, the bidder defined a desired quantity for purchase at the PX's maximum price of $2,500/MWh. At the other extreme, the bidder stated a quantity to be purchased at a minimum price. Since there were other opportunities to purchase power after the PX day-ahead market closed, the system was designed so that the demand bids, in conjunction with supply offers, established a market clearing price and quantity for each hour. After all parties' supply and demand bids were submitted in the PX, an Unconstrained Market Clearing Price (UMCP) was established by finding the price-quantity pair that occurs at the crossing of the supply and demand curves.

It might not be feasible, however, to deliver the desired quantity at this market clearing point, because the limitations of the transmission system had yet to be considered. After the UMCP was established and a set of winning bids for buyers and sellers had been determined, the feasibility of delivering the bid quantities was checked by considering the location of the winning demand and supply bids, and determining the flow of power over the transmission system that would be necessary to accomplish this outcome. To the extent some transmission paths were inadequate to meet this schedule, the ISO ran a congestion management auction to resolve the infeasible schedule. All the bidding entities provided the prices at which they were willing to modify, up or down, their bids and offers, in case congestion occurred. These bids were known as adjustment bids. The ISO, by changing schedules based on these bids, and feeding the results back to the PX, enabled the PX to publish its final prices based on feasible schedules. The prices were known as the ZMCPs or zonal market clearing prices, as each separate transmission zone would have a separate market-clearing price. Transmission congestion would cause a utility that procured power in the congested zone to receive a lower final energy allocation from the PX at a higher price than it would have in the PX's original day-ahead UMCP market. Thus, utilities in transmission-congested zones got less and paid more.

To the extent a buyer was unable to procure its forecasted demand from the PX day-ahead market, the PX ran an hour-ahead market.[9] There were at least four reasons why a buyer might wish to purchase additional power (or alternatively, sell excess power) in the hour-ahead market. First, its forecast of demand might have changed based on more current information. Second, it might not have been able to purchase its full day-ahead forecast based on the prices in the day-ahead market. Third, congestion may have made the delivery of the power it intended to purchase in the day-ahead market infeasible, resulting in a schedule cut. Fourth, a supply resource scheduled to provide power in the day-ahead market may have become incapable of meeting its schedule (*e.g.*, a forced outage of a generating unit), requiring an additional purchase from the market to make up the schedule shortfall. For each of these four cases the converse was possible, resulting in the need to sell excess power after the PX day-ahead market.

[9] At times this market was run for blocks of hours rather than individual hours, and was known as the "day-of market."

To the extent a buyer was unable to effectively purchase its needs by the time the hour-ahead market has passed, its remaining imbalance would be met by the ISO's real-time market. Some costs in addition to energy are allocated to purchases in the real-time market, making the use of this market particularly risky for a buyer. In addition, as described in Dr. Fox-Penner's testimony, the ISO's real-time market has prices that are established ex post, so there exists no demand elasticity in this market. As such, the ISO real-time market is particularly vulnerable to market power abuse. This provides sellers with a strong incentive to see that load must be served in this ISO real-time market.

Q. What did the independent market monitors conclude regarding underscheduling?

A. The independent market monitors concluded that withholding of supplies by generators and marketers was the primary cause of the California utilities' inability to purchase power at reasonable prices in the PX, and that buying both day-ahead and real-time was a major way for the utilities to protect themselves from even higher prices. The Market Monitoring Committee (MMC) of the PX reported to the Commission that:

> [D]uring the hours when end-use demand exceeds offered supply in the PX market . . . the supply side has substantial market power. . . . [B]ecause of the shortfall of supply, buyers (principally IOUs) are forced to buy in the real-time market. This has given rise to a controversy about so-called "load underscheduling" in the PX market; the claim is made that load servers are shifting their demand to the real-time market. . . .[I]t would be more accurate to say that supply had been "underoffered" in such hours. No matter what price buyers offered in the PX market, they could not have met all their needs; not enough supply was offered. Increasing their demand bid prices would serve

> only to increase the PX market-clearing price, with negligible effect on quantity.[10]

When the issue of underscheduling first arose during the summer of 1998, the PX and ISO's independent monitoring units investigated the practices, with access to the bidding behavior of buyers and sellers in both the PX and ISO markets. As a result of this investigation, the heads of those units prepared a joint memorandum and sent it to the CEOs of the PX and ISO. As the memorandum clearly states, as early as 1998, high prices observed in the day-ahead market were more the result of the withholding practices of sellers (underoffering of supply) than of underbidding of demand.[11]

Later, the practices of sellers became more extreme, as can be seen from a PX study contrasting seller and buyer behavior between 1999 and 2000. The PX management shared this analysis with the Electricity Oversight Board (EOB) in June 2000. The chart below, taken from that study, reflects the supply bids offered in the PX day-ahead market during on-peak hour 16 on August 25, 1999, June 15, 2000, and June 27, 2000.[12] The three thin lines represent the aggregate demand bids of buyers on these dates, starting with the August 1999 hour, then the June 15 and June 27 hours, reading from left to right. The thicker lines (labeled with dates) show the supply bids offered for those hours. The graphs depict the fact that although demand was willing to

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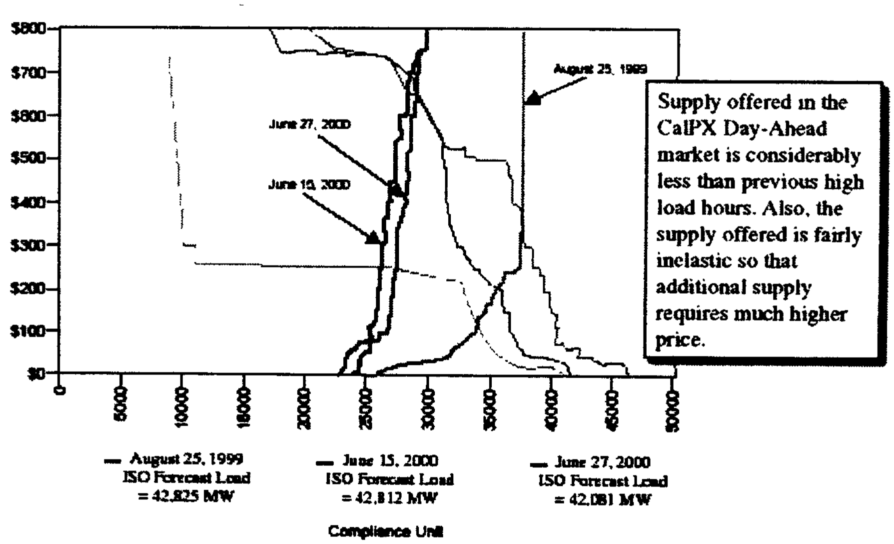
[10] *Second Report on Market Issues in the California Power Exchange Energy Markets* at 47, filed in Docket Nos. ER98-2843-006, *et al.* (March 10, 1999), Exh. No. CA-148 at 6.

[11] *See* Exh. No. CA-107 at 1.

[12] *See* Exh No. CA-248 at 2.

buy more, and at higher prices in 2000 (the two demand curves from 2000 are to the right and above the 1999 demand curve), there was as much as 10,000 MW less supply offered (the two supply curves from 2000 are 10,000 MW to the left of the 1999 supply curve). This demonstrates beyond any doubt that the cause of increased real time volumes was the lack of supply offered in advance of real time, and not the bidding behavior of buyers. Note, unlike the previous analysis I performed on supplier behavior, which included net supply curves, this chart represents just the gross aggregate supply and demand bid curves. To the extent sellers were also submitting demand bids, such as Reliant did on June 21-22 and July 19-20, 2000, the adverse impact on the demand supply balance of this behavior will not be captured in the PX curves below.

Comparison of Supply and Demand Curves
Hour 16
Focus on Supply



From EOB 06-29-00

In a report issued in June 2002, the General Accounting Office (GAO) found that sellers had used market power to drive up prices in the California market.[13] In particular, consistent with the position that SCE, PG&E, the PX's MMC, and the ISO's independent Market Surveillance Committee (MSC) had been stating for years, that suppliers were withholding power from the earlier markets, the GAO states on page 4 of its report:

> For example, several studies concluded that wholesale suppliers were able to exercise market power by withholding electricity from the market, only making it available at the last minute when buyers were desperate to acquire enough electricity to meet demand and therefore willing to pay higher prices.[14]

Some of those studies analyzing the withholding behavior of suppliers will be described later in this testimony.

A. Analysis of Bid Adequacy

Q. Was it possible for buyers to meet load obligations through purchases from the PX?

A. For much of 2000, the amount of supply bid into the PX was not sufficient to allow buyers to meet their load obligations without substantial purchases in the hour-ahead, real time and OOM markets. The graph below contains the time series of the ratio of the amount of supply bid into the PX at or below $750 per MWh to the ISO's load forecast. I call this ratio "bid adequacy." The bid adequacy ratio provides an indication of the degree of supply side under-scheduling in the California market.

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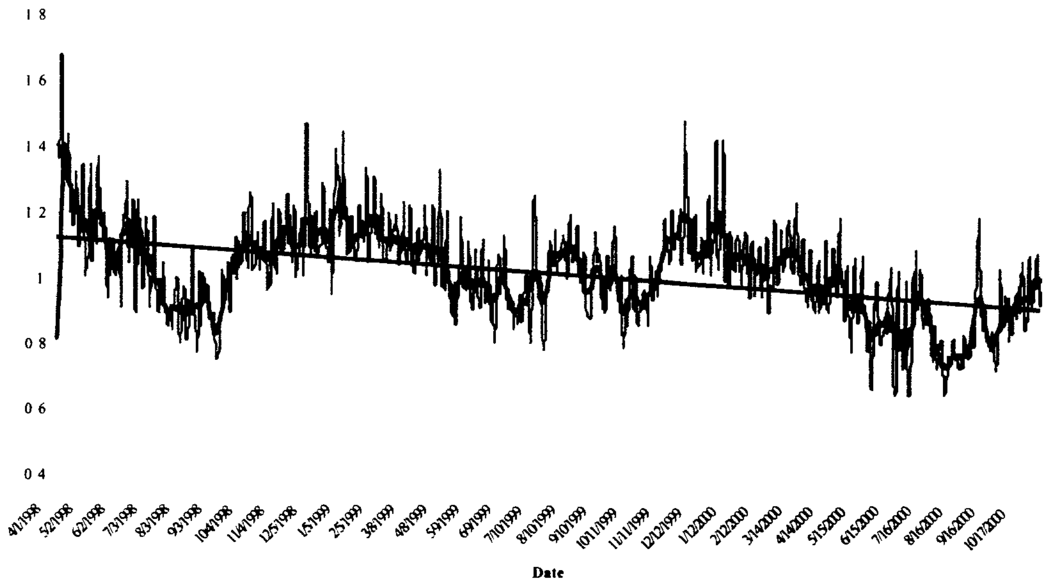
[13] The relevant pages from this report are included in Exh. No. CA-146.

[14] Exh. No. CA-146 at 5.

Quantity Bid Into the California Power Exchange at $750/MWh for Hour 16 as a Proportion of Total Load April 1, 1998 to November 30, 2000



Q. What does the ratio indicate about supply side under-scheduling?

A. When the bid adequacy ratio is 1.0 or greater, buyers can potentially satisfy all of their load obligations through the PX day-ahead market at some price equal to or less than $750.[15] On the other hand, when the ratio fall below 1.0, demand bids even at $750 will not allow buyers to meet their expected load obligation. This is the case regardless of the form of bidding strategy (e.g., price responsive, inelastic) undertaken by the buyers. If the ratio is less than one, there simply is not enough supply bid into the PX to meet load.

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[15] In Exh. No. CA-4 (Appendix A) at 26, I have also included a chart using supply bids up to $2,500/MWh. Such bids may not be indicative of the willingness to actually generate any power however, as sellers may have been willing to offer at very high prices purely as an arbitrage strategy, knowing that real-time imbalance charges would be less costly than sufficiently high priced PX sales, depending on ISO caps and other market rules.

Q. Why is this consistent with supply under-scheduling?

A. For markets to clear, it must be the case that the supply of electricity in all markets must equal or exceed load at all times. This is the case because electric power cannot be stored. During most of the crisis period, the ISO was able to locate sufficient supplies of power to maintain service. This implies that there was sufficient capacity available to meet load, but that not all of this capacity was bid into the day-ahead market. The fact that the amount of supply bid into the PX, even at the high price of $750/MWh, was below expected ISO load suggests that suppliers had pulled back from the day-ahead market. The marginal cost of production of all the units selling power in the WECC was well below $2500/MWh. Therefore, it is not conceiveable that suppliers failed to bid into the day-ahead market because they were unable to recover production costs. Rather, it appears that the reason that the amount bid into the day-ahead market fell so far short of load was because of under-offering by suppliers.

Q. Did anything change over time in the behavior of the sellers?

A. It is immediately apparent from the time series that the ratio decreases over time. Nevertheless, I have also added a trend line to illustrate the decline in bid adequacy over time.

The decrease in bid adequacy is indicative of movement by sellers out of the day-ahead market. That is, by the spring of 2000, even at $750/MWh there was not enough capacity bid into the day-ahead market for buyers to meet their entire load obligation. It was clear, however, that sufficient capacity was available to meet load at a cost of less than $750/MWh. Sufficient capacity must have been available since load was actually met through a combination of purchases from the day-ahead and shorter terms markets and that the market-clearing price in the real time and OOM markets in the spring of 2000 rarely reached $750/MWh. Sufficient capacity with a cost of production of much less than $750/MWh was available. In fact, using the FERC MMCP methodology, there was no cost basis for any bids over 10% of that value during this period. That the bid sufficiency index was below 1.0 for most of the spring and summer of 2000, however, indicates that this capacity was not bid into the day-ahead market.

Q. Why might the behavior of sellers have changed over time?

A. There may be several factors that explain the decline in the bid adequacy over time. These include the learning that comes from successfully increasing revenue as a result of increased withdrawals from the PX day-ahead market. There were also rule changes that made the practice of withdrawal from the PX day-ahead market more profitable. The movement of suppliers out of the day-ahead market is consistent with the notion that suppliers were engaging in some form of strategic behavior. The shift in selling patterns, however, may have also been due to changes in regulatory policy. In their report on the June 2000 price spikes, the ISO Market Surveillance Committee (MSC) suggested that the trend away from the day-ahead market might have been due to a shift in policy. The members of the Market Surveillance Committee were Frank Wolak, Robert Nordhaus and Carl Shapiro. They agreed with the conclusions I had presented to them at that time and argued that that the new replacement reserve policy adopted by the ISO in 1999 increased the incentives of sellers to under-schedule in the day-ahead market:

> The imposition of the Replacement Reserve cost allocation scheme in August 1999 created the possibility of an

> effective real-time energy price for generation unit owners double the real-time price cap on energy. This created significant incentives for generation owners to bid significantly higher prices in PX markets. The steeper aggregate supply bid curve in the PX resulted in less energy clearing in the day-ahead market, and greater under-scheduling of load and generation.[16]

With respect to the incentives for under-scheduling around price spikes and its effect on overall prices, the MSC determined that:

> By paying the Replacement Reserve price and the real-time energy price to generators supplying imbalance energy, the opportunity cost of selling energy in the day-ahead or hour-ahead markets can at least double during very high load hours. During hours with very high load, the Replacement Reserve penalty scheme pays generation (that is virtually certain to be providing energy in real-time) not to schedule in day-ahead and hour-ahead markets. This Replacement Reserve payment to generators is financed through the penalty that is charged to SCs that consume more energy in real time than they schedule on an hour-ahead basis. These incentives for forward market bidding and scheduling created by the current Replacement Reserve scheme are a major factor behind the high average energy prices during June of 2000.[17]

The upshot of their analysis is that the change in the Replacement Reserve cost allocation scheme made under-scheduling more costly for buyers and less costly for sellers. The connection between the growth in under-scheduling and the change in the Replacement Reserve policy became particularly apparent during June of 2000 when as much as 7,000 MW of replacement reserve was procured by the ISO at the $750 cap

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[16] California Independent System Operator, Market Surveillance Committee, An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets, September 6, 2000, at 22, Exh. No. CA-232 at 2.

[17] *Id.* at 23, Exh. No. CA-232 at 3.

price, and the larger majority of this replacement reserve was also dispatched in the ISO's real-time energy markets, at times receiving an energy plus ancillary service payment as high as $1,500/MWh. More money was spent on replacement reserves during the second week of June in 2000 than during the entire year of 1999. Yet record levels of real-time load occurred during that same week.

B. SCE's and PG&E's Load Bidding as Described in Their Responses to FERC Investigative Data Requests

Q. How did SCE and PG&E bid their load into the PX day-ahead market?

A. In May 2002, in response to an investigation by the Federal Energy Regulatory Commission (FERC), memoranda were made public in which attorneys in Enron's outside law firm candidly described and commented upon various practices in which Enron marketers engaged. These practices were designed to manipulate the PX and ISO markets in ways that would create artificial opportunities for Enron to receive enormous payments of money through phony market transactions. (I will describe and comment on these manipulative strategies below.) As a result of the revelations in the Enron memoranda, FERC sent data requests to all participants in the California market, requiring them to answer a series of questions to determine the extent to which other firms were engaged in similar practices. In response to these questions from FERC, SCE submitted the following declaration describing its scheduling practices:

> SCE did not build under-scheduling into its demand forecasting models or demand forecasts for trading with California markets during the period 2000-2001. Every attempt was made to accurately forecast the SCE system demand, and that part of the system demand for which SCE was responsible for buying power (UDC demand). Forecasts of system load were sent daily to the ISO for informational/operational purposes, along with the

temperature forecasts upon which the demand forecasts were made. The ISO was always informed of SCE's most accurate system forecast, and this information was sent to it every day by about 8 AM of the day prior to the trading day. For most of the relevant period, SCE was permitted to purchase primarily in three markets to serve its retail customers: the PX day-ahead and day-of markets and the ISO real-time market. (Pacific Gas and Electric Company, et al., 77 FERC ¶ 61,265 at 62,088-62,089 (1996).)

SCE's objective was to purchase energy for its customers at the lowest possible cost. Accordingly, as long as no transmission congestion was anticipated, SCE submitted bids into the PX day-ahead market which would result in a purchase of 95 to 100 percent of its customers' expected energy needs in each hour through the day-ahead market, depending on SCE's forecast for the next day's PX prices and the prices SCE expected in later markets – particularly the real-time market which was subject to a Commission-ordered price cap. SCE would also reduce its demand bids to reflect its expectations about transmission congestion. For example, SCE would bid in a way so as to purchase as much of its needed supply as it expected to be available after the ISO completed its congestion management process. The ISO and PX Tariffs permitted demand bidders to submit to the PX demand/price curves that, under certain circumstances, would result in only a portion of a load-serving entity's forecasted demand being met ahead of real time. Where the price sellers demanded in the PX day-ahead market exceeded the price SCE was willing to pay, SCE's demand bid would result in less than 100% of its forecast load being purchased in the day-ahead market.

In such circumstances, SCE would purchase some of its customers' electricity demand in the later markets. In general, SCE would bid to buy its shortfall in the PX's day-of market, though this market was typically illiquid and insufficient to meet the shortfall. In this case, some of SCE's load would ultimately be met in the ISO's real-time market. Some of SCE's load would also be met in the ISO's real-time market because of (1) transmission congestion or (2) actual load exceeding forecast load (forecast error).[18]

PG&E's buying strategy, designed for the purpose of minimizing its purchase costs, is described in testimony to the CPUC.[19] Similar to SCE's buying strategy described above, PG&E used demand bid curves submitted to the PX as a means of filling its entire forecasted load at reasonable prices. To the extent supply offered into the PX's day-ahead market was not available at reasonable prices, PG&E's demand bid curve was sloped so as to balance its day-ahead purchases with real time purchases.

C. Recommendations from the PX's MMC and PX Management on Underscheduling

Q. How did the market monitors assess underscheduling?

A. One of the factors affecting the amount of power purchased by an IOU in the PX day-ahead market was its use of a demand bid curve that was sensitive to PX day-ahead prices. The IOUs' bidding was such that as prices rose dramatically on days like June 27, 2000, IOU purchases from the PX were reduced. But contrary to the assertions of many sellers, bidding a price sensitive demand curve was a practice that the PX actively encouraged.

In its Second Report on Market Issues, the PX Market Monitoring Committee (MMC) stated:

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[18] Response of Southern California Edison Company to Requests for Admission, Production of Documents, and Other Requests for Information; Affidavit, FERC Dkt. No. PA02-2-000 (May 22, 2002), Exh. No. CA-293 at 9-10.

[19] *See* PG&E Annual Transition Cost Proceeding Testimony, Chapter 1 at 17-20, Exh. No. CA-240 at 20-23.

> Without these "structurally induced" IOU demand elasticities in high-demand hours, the PX market would behave much worse than it has. If the IOUs were to bid a vertical demand curve, the price in Figure 14 could reach an arbitrarily high level *without eliciting greater supply, at least in the short run.*[20]

The MMC then concluded that buyers such as SCE and PG&E did not reduce their demand enough in response to price (what the MMC calls structurally induced demand curves):

> Therefore, the "structurally induced" demand curves of the IOUs undoubtedly helped them and their customers. Yet, paradoxically, *the IOUs might have reduced their payments considerably further, without incurring a penalty in terms of lower quantities.*[21]

And finally:

> One conclusion, however, seems clear: the IOUs have not fully exercised their power to influence prices.[22]

In addition to the clear recommendation of the MMC to bid even more price responsive demand, PX management regularly approached SCE with the specific recommendation to bid more "structurally induced" demand. It is absurd for sellers to suggest that this behavior was inappropriate, while the MMC and the PX management were encouraging it. The sellers' complaints were clearly intended to promote their own self-interest at the expense of California ratepayers and utilities. On the other hand, the IOUs supported those recommendations that were consistent with their own conclusions,

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[20] Exh. No. CA-148 at 6 (emphasis in original).

[21] *Id.* at 7 (emphasis in original).

[22] *Id.*

as well as from entities in the best position of authority on the matter and access to the best information.

V. An Example of Underscheduling: June 27, 2000

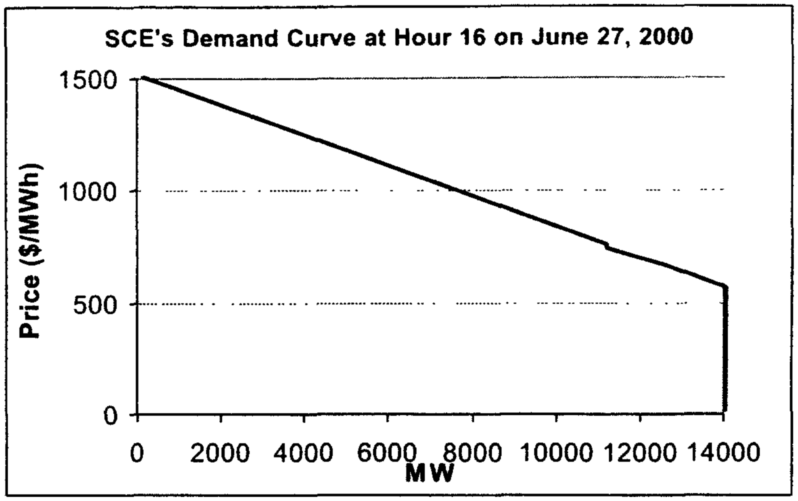
A. Demand Bids

Q. Can you walk through a specific example of underscheduling?

A. Later in my testimony, I present the analysis of data involving all of the IOUs, but for the purposes of looking at an illustrative day, I will examine the bidding by SCE and by sellers for deliveries on June 27, 2000. On June 26, 2000, SCE submitted its day-ahead (DA) demand bid to the PX based on its best load forecast for the next day, June 27, 2000. The bidding strategy was well established: to minimize the total purchasing cost from all markets, PX day-ahead, PX day-of, and ISO real time, following the rules and recommendations of the PX and ISO.

As an example of what the DA schedule looked like, consider SCE's demand bid and PX results for hour 16, the peak load hour, on June 27, 2000.

The full DA bid curve for the hour was 13,938 MWh, which was SCE's best forecast of UDC load. SCE submitted this as part of its bid curve based in part on its forecast Unconstrained Market Clearing Price (UMCP) of $556.00 per MWh. The demand bid curve submitted by SCE included a reduction in quantity of 1,419 MW when price exceeded $656.00. The curve involved a further reduction of 1,419 MW in quantity if price exceeded $731.00. Beyond that, the bid curve stayed unchanged until the price reached $749.99. Finally, the bid curve was reduced to zero as the price reached $1,499.99. This bid curve is shown in the graph below.



The PX day-ahead initial preferred schedule (IPS) awarded to SCE was 12,690 MWh at the UMCP of $650.00. However, due to congestion management, the final schedule was reduced to 12,026 MWh at the congested ZMCP of $653.00. Therefore, there was a total reduction from SCE's DA full bid in the amount of 1,912 MWh. No additional supply was available to SP15 due to the transmission constraints.

SCE tried to recapture this "congested out" amount in the PX day of (DO) market on June 27, 2000 by submitting a DO bid for hour 16 based on a newly forecasted balance of demand, 2,037 MWh, at the MCP price of $749.99, and zero bid at $750.00.

The PX awarded SCE only an additional 214 MWh at $750.00 in the DO market (for a total of 12,240 MWh), which left a shortfall of 1,823 MWh compared to SCE's DO full bid (and load forecast). SCE would have to purchase this amount in the ISO real-time market, if the forecast load turned out to be accurate.

B. SCE's June 27, 2000 Purchases in the ISO Real-Time Market

Q. What happened to SCE's June 27, 2000 load after the PX market had been run, and a shortfall had to met in the ISO real-time market?

A. SCE's actual purchase in the ISO real-time market turned out to be fairly close to the expected shortfall. The metered UDC hourly load for hour 16 that day was 14,576 MWh, compared to SCE's DA forecast of 13,938 MWh and the DO forecast of 14,064 MWh. The forecast errors were negative 638 MWh and negative 512 MWh, respectively, for the DA and DO forecasts. That represents a forecast error of 4.4% and 3.5%, respectively, well within the acceptable range of forecast error for peak hours, especially during the heat that was being experienced at the time.

The PX awarded SCE a total of 12,240 MWh from both the DA and DO markets. This implies that SCE bought 2,336 MWh in the ISO real-time market, that is, 16% of the actual UDC load. Out of this total ISO real-time market amount, 1,823 MWh, or 78%, was due to a supply shortage and/or congestion management, and 512 MWh was due to forecast error. In other words, if there had been no congestion management and no shortage of supply, SCE would have had to buy only 512 MWh, or 3.5% of its load, in the ISO real-time market.

C. The Impact of Bidding a Vertical Demand Curve

Q. What would have happened if SCE had made every effort, been willing to pay any price, to procure in the PX day-ahead market, on June 27, 2000?

A. In the following section of the testimony, I will show what would have happened if SCE had submitted a bid curve that was vertical and price-inelastic, *i.e.*, if SCE had tried to purchase the full forecasted load at all price levels up to the highest limit of $2,500.00, as the sellers apparently would recommend that the buyers should have done.

Two important points about this hypothetical analysis of a vertical demand curve are in order. First, such a curve is, in fact, unacceptable according to the PX Bidding and Bid Evaluation Protocol (PBEP). PBEP Rule 2.4.1.e states that "for Demand Bids, the piece-wise linear curve . . . must have a downward slope." The PX would not have accepted a completely vertical demand bid curve. Second, in this analysis, all other day-ahead bids submitted for June 27, 2000, both supply and demand, by other UDCs and market participants are assumed unchanged because SCE had no way to know, and certainly no way to change, other's bids. This assumption, in fact, is necessary to show the impact that SCE's action *alone* would have had on the interruption.

I have reconstructed the PX aggregate demand and supply curves for hour 16 in the day-ahead market for June 27, 2000, replacing the original SCE demand bid curve with a vertical demand bid curve. Based on the results of this analysis, I found that if SCE had offered to pay any price to purchase its full forecast hour 16 load, *i.e.*, if it had submitted a vertical demand bid curve, the PX DA market for hour 16 would have increased by only 65 MWh due to limited supply offers. This implies that the ISO real-time market volume for that hour would have been reduced by a mere 65 MWh. This would have had an insignificant effect on the market as a whole, since the size of the ISO real-time market was more than 8,000 MWh. In other words, if SCE had submitted a bid with a vertical demand curve, the size of the ISO real-time market would have been reduced by less than one percent. While such a bid would have allocated more supply to

SCE, it would have resulted in less supply to other participants, with only a net 65 MWh (approximately 0.2%) increase in total PX supply.

Assuming SCE had been successful in its vertical demand bid, and assuming there had been no congestion management, SCE would then have been able to purchase its full forecast hour 16 load of 13,938 MWh at the MCP of $730.56, in the PX day-ahead market. However, this would have meant an increase in price of $80.56 per MWh from the original price of $650.00. Thus, SCE would have had to pay more than $1.1 million of additional cost for hour 16 alone.

VI. Enron and Others' Strategies and Their Relationship to Load Underscheduling

Q. What impact did strategic market manipulation games have on the underscheduling problem?

A. In May 2002, FERC released several memoranda and notes from Enron obtained through discovery in its investigation into the California electricity markets. Exh. No. CA-78 is the December 6, 2000 memorandum from Stoel Rives, Enron's outside law firm, describing several of Enron's trading practices used to take advantage of the California market.

The first of the strategies described in this memorandum is the so-called "inc-ing" load strategy, otherwise known as "Fat Boy." This strategy was predicated on the assumption that at certain times the real time prices will be "favorable" to sellers. In fact, the memorandum itself attempts to blame the utilities' "underscheduling of load" as the reason for this opportunity. Enron, in this "Fat Boy" strategy, uses phony load schedules matched against a quantity of power that it has acquired through a contract, effectively to sell that power into the real-time market of the ISO. By submitting a phony load that does not materialize, Enron has a supply that exceeds its demand, and is viewed as having a positive imbalance in the ISO's real-time market. Enron will thus be paid for effectively selling its excess power in the real-time market. But when Enron engaged in this strategy it also withheld the sale of its contract power from the PX day-ahead market, making it unavailable for SCE, PG&E, or other buyers to purchase in advance of real time. This helped create an artificial supply shortage in the day-ahead market, thus forcing buyers like SCE and PG&E to increase their purchases in the real-time market. Enron would then "solve" the problem it created by making extra supply available at high prices at the last minute in the real-time market.

"Fat Boy" was an intentional power withholding strategy that resulted in large real-time market purchases, which Enron could then blame on buyers as underscheduling load. In fact, Enron actually had the audacity to claim it was helping the ISO to solve the underscheduling problem, when what the ISO really wanted was for entities like Enron to sell the needed quantities of power in the day-ahead market. Unfortunately, even some at the ISO may have been duped by this "blame the victim" tactic. As described in Dr, Fox-Penner's testimony, many market participants, not just Enron, employed the Fat Boy strategy. In addition to Enron, Dr. Fox-Penner identifies Mirant, Sempra, Powerex, and others as significant users of Fat Boy. Powerex, for example, was purchasing power from the PX in August of 2000, as shown in the net supply graph in my bidding section above. While they were buying power out of the PX, they were using Fat Boy as means of selling this power into the ISO-s real-time market.

Another example is encompassed in Exh. CA-38, which includes a December 13, 2000 e-mail in which Powerex claims to be helping California by selling all it can into the PX market.[23] The second page of the exhibit shows Powerex's bids on December 12, 2000 for delivery on December 13, 2000.[24] Powerex's actual behavior is revealed in its actions. It was buying an average of over 1,000 MW across the 24 hours. It sold as much as 50 MW into the PX, only during off-peak hours. Their net position was purchasing power from the PX at an average rate exceeding 1,000 MW. It is difficult to see how this was helping California through the crisis, but its impact on the buyers in the PX day-ahead market is obvious.

The next of the Enron strategies described in the memorandum also contributed to the ISO's real-time market problems, and also resulted in what Enron could characterize as "underscheduling." Enron would buy power out of the PX market at effectively capped prices, and sell that power out of state at higher prices, once again taking power away from the California IOU buyers in the day-ahead market, and leaving them with no choice but to meet some of their load in the real-time market.

The memorandum later describes an Enron practice called "Load Shift." This strategy involved bidding load so as to create transmission congestion in the day-ahead schedule on a path where Enron owned the transmission rights. Enron would thus receive payments both for transmitting the power and for relieving the congestion it had deliberately created. The impact of this strategy on IOU buying was that when an IOU

[23] Exh. CA-38 at 1.

[24] *See id.* at 2.

tried to buy in the day-ahead market to meet its demand in, for example, SP15 (California's southern transmission zone), congestion from Northern California to Southern California would appear to the ISO to be significant, making the IOU's schedule infeasible and requiring the ISO to cut some of the IOU's day-ahead purchases. The IOU's schedule would ultimately have to be met in the ISO's real-time market, an outcome naive or sinister parties could characterize it as load underscheduling, even though it was the result of the scheduling congestion created by phony Enron load bids.

"Ricochet" was another Enron strategy that was used by many market participants, as described in Dr. Fox-Penner's testimony. It was also a strategy that resulted in forcing demand into the ISO's real-time market. In this strategy, a seller would schedule its California power for export outside of the ISO area in the day-ahead scheduling. This would once again reduce the supply available for purchase in the PX day-ahead market, making it impossible for buyers to meet their demand without using the ISO's real-time market. The power scheduled out of the ISO area would then be "parked" there until it could be "imported" and sold to the ISO's real-time market. In the case of Ricochet, Enron wasn't even one of the major users of the strategy. As Dr. Fox-Penner's testimony notes, Powerex was the largest user of the Ricochet strategy, and Powerex, along with a list of six others that does not include Enron, accounted for 92% of the potential individual party Ricochet transactions. Dr. Fox-Penner identified over 15,000 potential hourly instances of Ricochet transactions including over 2 million MWhs of energy.

Thus, the Enron memo describes several strategies that involved taking power out of the supply curve from the PX day-ahead market so it could be sold into the ISO's real-time market under conditions when the ISO was "desperate." Such withholding strategies increased the day-ahead prices by reducing the available supply in that market, and resulted in high real time prices by increasing the demand in that market, which lacked any demand elasticity. Once again, the Enron memorandum tried to direct attention away from the Enron withholding strategy by accusing the buyers of underscheduling, and claiming to help solve the problem by shifting supply from the day-ahead market to the real-time market.

Other market participants, such as Reliant, employed these manipulative strategies while simultaneous blaming load for underscheduling. They now represent their actions as being either responsive to demand bidding strategies, or as helping the ISO meet its real time needs. Through a strong misinformation campaign, sellers have been working to mislead the ISO and FERC. The state of California has also been subjected to these strategies as a major power buyer in 2001 when SCE and PG&E could no longer continue to pay the exorbitant prices demanded by the sellers.

The existence of a set of strategies by merchant suppliers and marketers to take advantage of the market at the expense of consumers, resulting in higher cost and degraded reliability, came as no surprise to me. In my role as Director of Market Monitoring and Analysis, I have been preparing evidence for some time about market abuses that would require FERC intervention. As early as August 2000, I provided the FERC with a blueprint describing various games that I knew were being played in the

California market, and various others I suspected.[25] That memorandum described strategies later to be known as Ricochet and Load Shift, as well as other supply withholding behavior. I also provided FERC with suggestions as to how to investigate the use of such strategies. It was not until FERC made the Enron memoranda public in May 2002 that the public in general became aware of these strategies.

For example, in an internal e-mail dated February 19, 2000, Powerex trader Thomas Bechard described Powerex trading strategies and their impact on the market:

> [W]e have come up with a possible reason why the Beep model has been so far off lately. . . . [I]t appears it is due to significantly more overgeneration in California in recent weeks. The increase in overgeneration began after we started putting in high priced buy bids in the sup market to protect our price taker sales. It may be that this has skewed the entire sup market up in price and resulted in generators underscheduling in the day ahead and hour ahead markets so they can overgenerate to take the beep.[26]

The meaning of this statement, which has been corroborated by the observations of Powerex's ISO bids as described in Dr. Fox-Penner's testimony on Powerex gaming, is that Powerex was intentionally bidding up the ISO real-time market through bids to buy at high prices, while simultaneously using a "Fat Boy"-type strategy to sell uninstructed energy into the ISO real-time market to benefit from these high prices. Powerex's analysis, according to the quote above, also concluded that by driving up the

[25] See Exh. No. CA-151 at 1-4 ("FERC Told By Edison of Market Rigging By Enron," Los Angeles Times, May 21, 2002).

[26] Exh. No. CA-176 at 296. "Sup" refers to the ISO's supplemental energy market which is another term for the real-time market. "High priced bids in the sup market" would therefore be bids to buy power at high prices.

real time prices it was causing generators to underschedule (or underoffer) in the PX day-ahead market so as to sell into the ISO's real-time market and reap some of the market power rents created by the Powerex bidding. The evidence clearly demonstrates this strategy was successful in raising real time prices.

This unguarded statement also contrasts with statements by Powerex and others that underscheduling of loads by buyers was responsible for the market crisis. To the contrary, Mr. Bechard's statements in his internal communications at Powerex make clear his perception that it was "generators" that were underscheduling in the PX day-ahead market – a fact that will be further demonstrated in the analysis below. Another example of the perverse logic used to blame load for underscheduling while simultaneously causing the problem is provided in the deposition answer below by Mr. Margolis of Powerex:

> What we did here was purchased energy from the Cal PX in the day ahead market. Someone must have supplied that energy by committing the unit or otherwise. We then took the energy and sold it in realtime. And an extra sale in realtime would have taken care of some of the underscheduling of the utilities meaning lower demand in realtime that the ISO had to go procure elsewhere, which would, I expect – I think by definition would lower the price in realtime.[27]

That is how Mr. Margolis describes the practice of taking power out of the PX day-ahead market, such that buyers cannot acquire that power to serve their load on a day-ahead basis, and then selling that power in the ISO real-time market. He implicitly claims that

[27] Exh. No. CA-174 at 54.

Powerex was helping the ISO deal with underscheduling of the utilities through this practice. Thus, by denying the utilities the opportunity to buy in the day-ahead market, and thus forcing them to meet our load in real-time, Powerex can take credit for mitigating the problem of utilities buying in real-time instead of the day-ahead market. This completely perverse logic is typical of the "blame the victim" approach frequently observed during the California crisis.

On January 31, 2003, FERC and Reliant stipulated to a consent agreement in which Reliant would pay $13.8 million to purchasers in the PX market on June 21-22, 2000. Accompanying this stipulation was the release of transcripts of trader tapes clearly depicting a physical withholding strategy from the PX that Reliant used to increase short-term and forward market prices for its personal gain. Dr. Berry provides more detail of Reliant's withholding strategy in her testimony. As noted, Reliant's market power abuse intended to raise prices was not limited to these two days in June 2000. Dr. Berry also shows that others showed similar bid withholding patterns. Furthermore, the market power strategies used by Reliant inhibited buyers' ability to purchase power in the PX DA market through both supply withholding and Reliant's own demand purchasing. Reliant representatives then proceeded to blame underscheduling of load for the market problems in testimony to Congress, while obfuscating Reliant's own role.

The evidence of supplier behavior as the cause of underscheduling is overwhelming. The Enron strategies, the Powerex market manipulation, and the Reliant market power abuse are just a few examples of strategies to manipulate prices in the PX day-ahead or ISO real-time market, or to create congestion. As Dr. Fox-Penner enumerates in his testimony, there were thousands of instances of these abuses, and many participants used these strategies. For all those strategies I have described, and several others described in other testimony, an effect of the strategy is the reduction of power offered for sale in the PX day-ahead market. The evidence clearly demonstrates that this reduction in offered supply was the cause of underscheduling. By forcing demand to be procured through the ISO's real-time market, through these myriad manipulative strategies, sellers ensured that market prices would be established for their sales in a market that lacked any demand response. Both the direct impact of the aforementioned strategies, and the forced movement of demand out of the day ahead market and into the ISO's real-time market resulted in increased profit for those engaged in the manipulation, and others selling into the same markets.

Demand bidding had some impact on the final outcomes in the PX, but the large majority of the time when the ISO had problems and these were exacerbated by large real-time markets, demand bidding behavior could not have fixed the problem that supplier behavior had created. Below, demand bidding behavior is described, and analysis of the impact of alternative supply or demand behavior on underscheduling is examined.

VII. The Impact of Supply Withholding on Underscheduling

Q. What analysis have you conducted regarding the impact of supply bidding behavior on underscheduling?

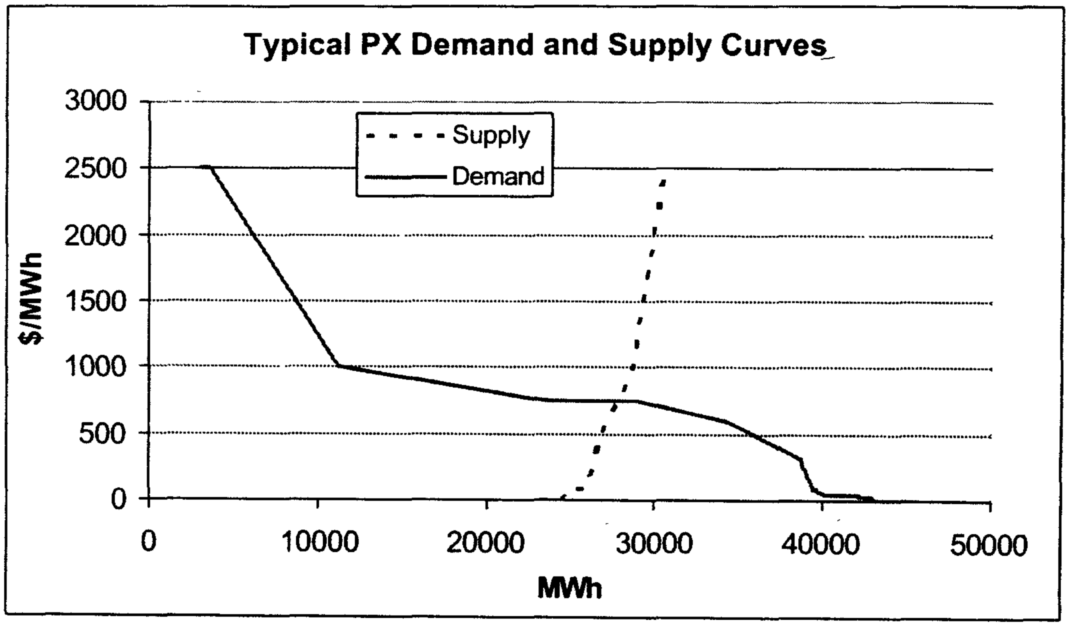
A. In my testimony in Section III above and in the testimonies of Drs. Fox-Penner, Berry, Hanser, and others, the California Parties have shown that substantial economic and physical withholding occurred by many participants in the market. Such withholding behavior associated with the PX day-ahead market, as will be shown below, provides the real cause behind underscheduling.

Q. What would have happened if supply had been offered at reasonable prices?

A. I performed an analysis of PX market clearing prices and quantities that would have resulted if the suppliers had offered their power into the PX DA market at just and reasonable prices, instead of their actual bids. To perform this analysis, I reconstructed the PX supply curve, capping all bids using the MMCP formula adopted by the FERC for the refund period calculations. In other words, I constructed a supply curve limiting supplier bids such that no supplier bid exceeded the heat rate of the least efficient unit times the spot gas price based on the gas price index used in the refund case to date, plus $6/MWh for O&M. This construction simulates the supply curve under the assumption that all bids at or below the MMCP are reasonable, but bids beyond that level are excessive. Note that to the extent any individual bidder bid higher than its heat rate times gas price index plus O&M adder that bid would not be altered unless it exceeded the market MMCP as established by the most costly unit in the market.

In order to ensure the quality of the analysis, I first reran the PX market using supply curves and demand curves I reconstructed from supply and demand bid data. This test verified not only that I could reconstruct the demand and supply curves, but that I could reconstruct the PX's market clearing price mechanism. In every hour I was able to match the PX's UMCP to more than three significant figures.

An example of a typical aggregate demand and supply curve as reconstructed from the PX supply and demand bids is shown in the graph below. This graph, and those that follow in this and the next section, use the actual PX data and modifications to that data described in this analysis for the dates of June 28, 2000 at hour 15, and July 19, 2000, hour 18. These dates and hours were chosen because they allow for illustration of each of the possible demand/supply cases evaluated.



It should be noted that this is a static analysis, in that it does not reflect changes in behavior by buyers and sellers that might have occurred as a result of observing different demand and supply outcomes over time. This analysis merely provides insight into what would have happened at any particular time if the supply curve were altered, and all other factors remained the same. That notwithstanding, I believe this analysis provides great insights into the real drivers of the PX day-ahead market clearing, and as such demonstrates the real causes of underscheduling.

I should also note that I limited my analysis to the May through September 2000 period, given that FERC has already concluded that prices after October 2000 were unjust and unreasonable. The argument that the IOUs bought too little power after October 2000 is premised on the notion that the IOUs should have been willing to pay much more for their power than they in fact paid. FERC has already rejected that notion by holding that the prices that were paid were already at unjust and unreasonable levels. Further, as I demonstrated in the supply bidding analysis earlier, the withholding of power by sellers from the PX market continued, even in December 2000.

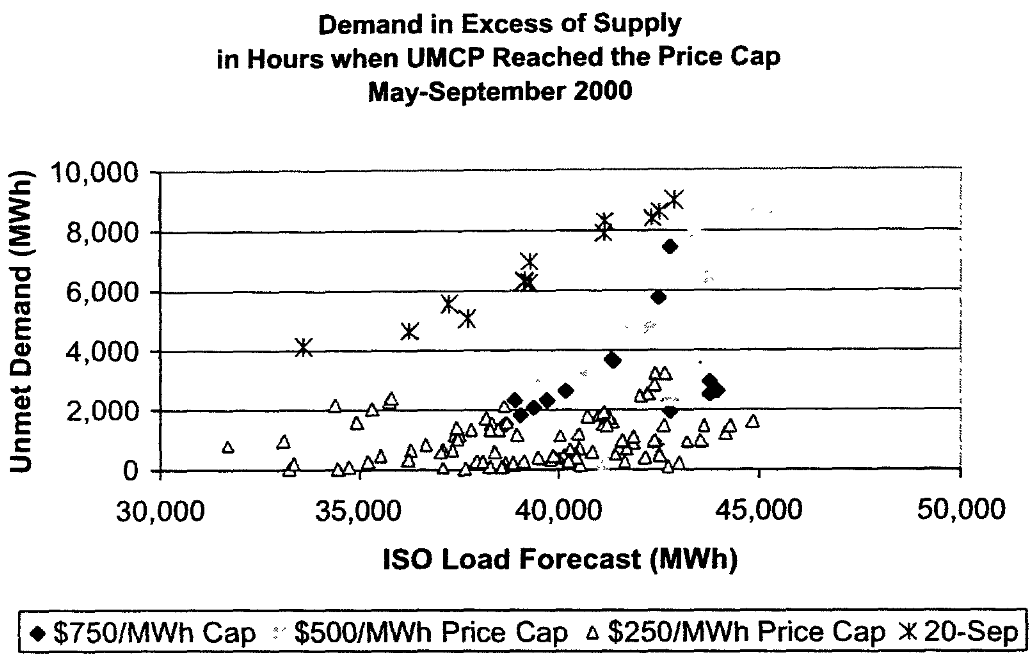
Q. What did this analysis reveal?

A. In order to interpret the results of this analysis, I categorized the hours based on ISO and demand/supply conditions. First, since the purpose of this analysis is to explain the real causes of underscheduling, I limited the hours from which to draw conclusions to those hours in which the ISO might have concluded that there was a problem that impacted its operation. The problem the ISO feared relating to underscheduling was not knowing if sufficient resources would be available to meet its real-time load. If the ISO felt that insufficient resources would be available, it declared an emergency condition. When emergencies were declared by the ISO during the May through September 2000[28] time period, I concluded that the ISO would consider this an hour of underscheduling that impacted its operation, and I included the results of this hour in my study. There were 208 such hours in the May through September 2000 period.

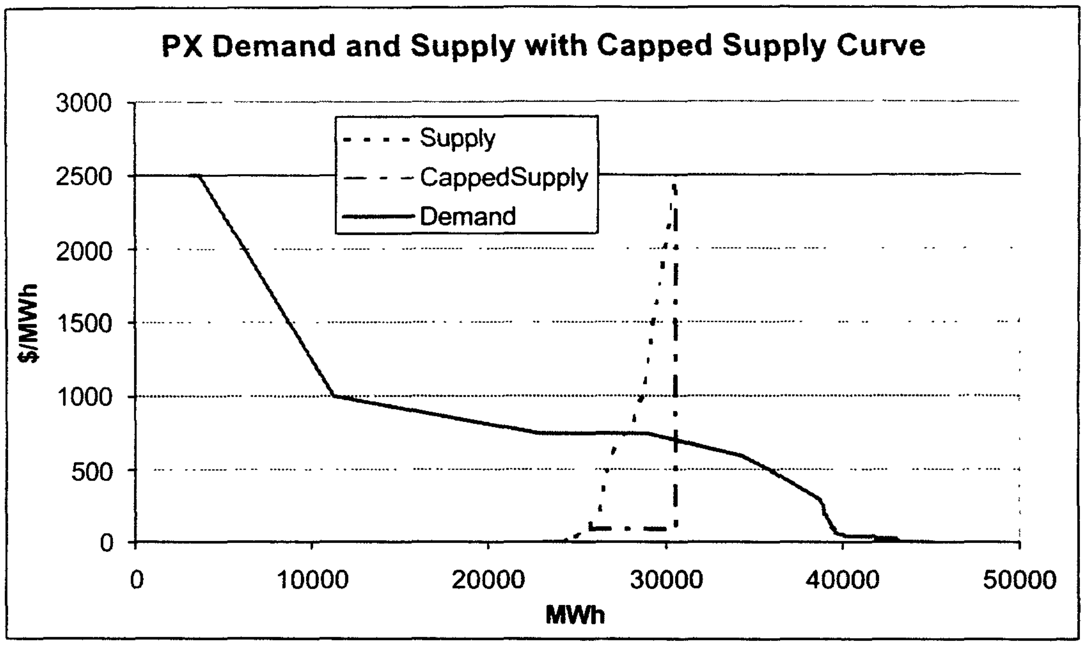
[28] The PX bid data was missing for some period of time after September 27, 2000, so this analysis only includes data between May 1, 2000 and September 27, 2000.

Examining those 208 hours in further detail, I identified those hours in which insufficient supply was made available to clear the market. In such instances, the elimination of economic withholding through the imposition of the MMCP cap on supply bids is not sufficient to eliminate underscheduling because there is such physical withholding from the DA market as to make scheduling within 95% of full load impossible. Such instances of underscheduling must clearly be entirely attributed to the physical withholding of supply, since no demand bid is capable of eliminating underscheduling.

Another quantification of this effect was provided by a PX analysis of insufficient supply offers to clear the market during hours when the PX market cleared at the ISO bid cap. In other words, during such times as load was willing to pay in the PX DA market as much as they might possibly pay the ISO for energy, if there was still insufficient supply offered to clear the market, then the PX identified this hour in the graph it developed, shown below.

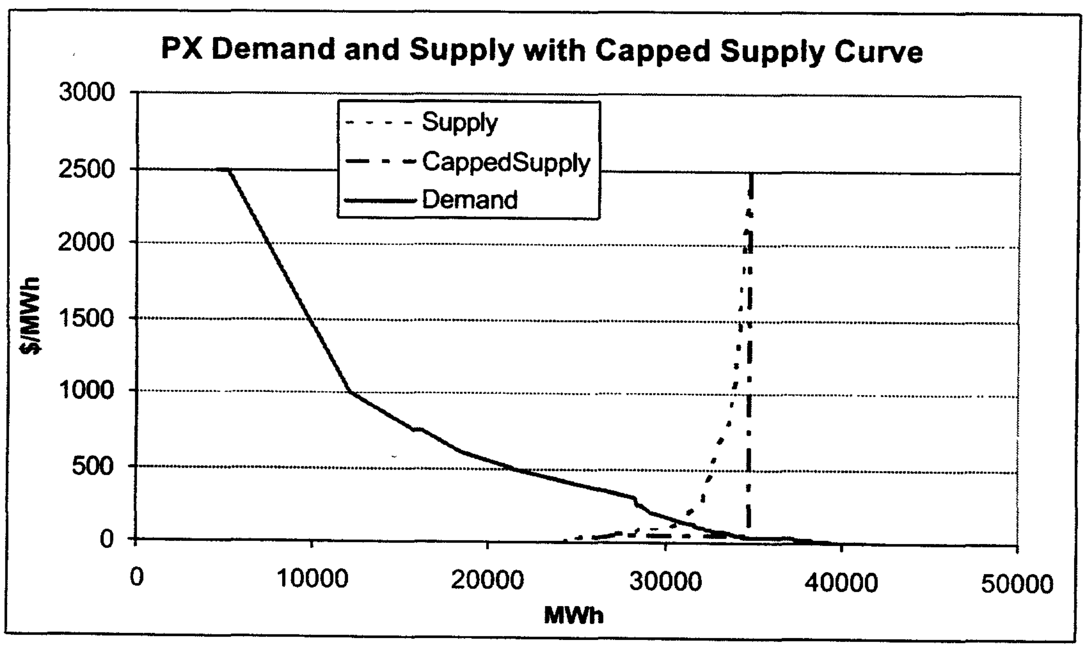


In hours with insufficient supply at any price, the market still clears, but it clears based on the demand bid at the maximum quantity of supply offered. The clearing price is set by the demand bid, not the supply. One such typical hour from my analysis is shown in the graph below, in which the supply curve has been capped at the MMCP, but insufficient total volumes of supply offered result in demand crossing supply at the vertical limit of the supply curve.



While this situation might appear to be an illustration of scarcity pricing, in fact no scarcity existed during these periods because supply was made available to clear the market and serve load, just not made available to the PX. Suppliers withheld their output and sold it to the ISO either as OOM or in the real time market. The results of my analysis showed that in 201 of the 208 summer 2000 emergency hours (96.6% of the hours), there was insufficient supply offered to the market to meet the needs of the buyers. In these hours, load cannot be held responsible for the underscheduling because there was no load bid that could have avoided the underscheduling.

I then examined those hours when the market did clear based on supply bids mitigated at the MMCPs. In other words, I looked at the 7 of 208 summer 2000 emergency hours in which sufficient supply was bid into the market to meet buyers' needs. For these seven hours, I examined the impact on the market clearing quantities in the PX DA market of reasonable offers by sellers. The results show that that if sellers had offered the same supply but capped their supply bids at reasonable prices as determined by the MMCP calculation, an average of 91% of the load would have been served in these hours. While this is slightly less than the arbitrary 95% standard the ISO has espoused, it shows that the issue of underscheduling by load essentially evaporates if supply had been offered at reasonable prices. And there are other factors that can explain the missing 9% during the 7 hours when sellers offered enough supply for buyers to have the potential of meeting their load in the PX day-ahead market. These include the impacts of real and phantom congestion that are properly modeled into the IOU demand bidding. (That is, if an IOU reasonably expected that congestion might lead to curtailment of supply, it might reasonably reflect that in its demand bidding so as not to drive up prices by purchasing supply that could not be delivered given congestion.) A graph of one of these types of hours is shown below:



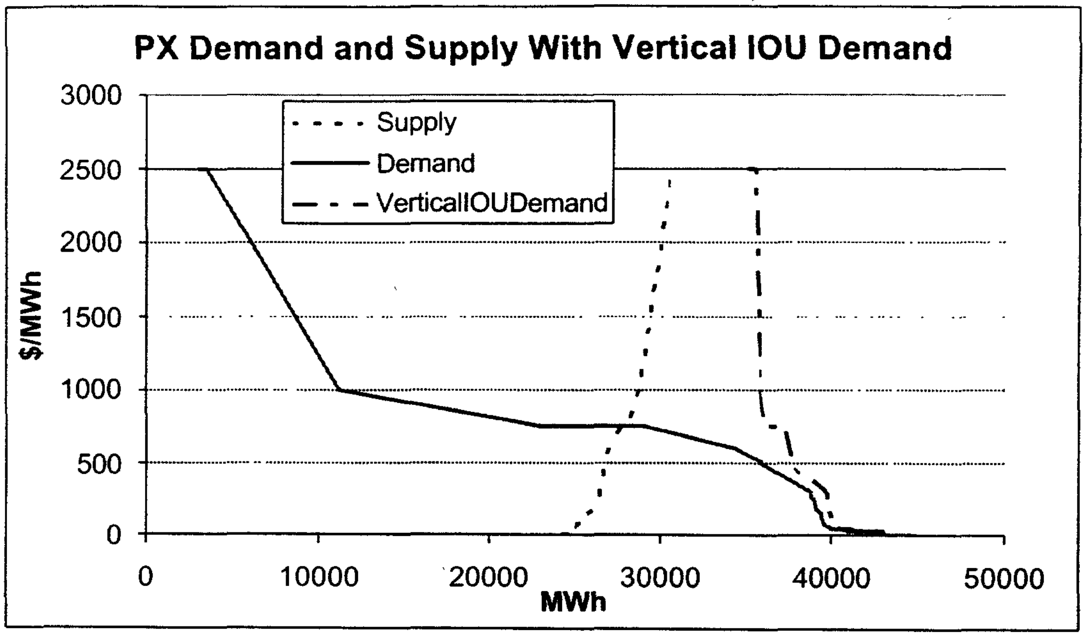
The conclusion, once again, is that underscheduling can be attributed to the unwillingness of suppliers to offer power at just and reasonable prices (economic or physical withholding) and thus cannot, as has been asserted by the sellers, be attributed to load bidding strategy.

VIII. The Impact of Vertical Demand Bidding on Underscheduling

Q. What would have happened if demand had been willing to pay any price to meet its load in the PX day-ahead market?

A. An additional analysis I performed relating to the underscheduling question is what would have happened if demand had been willing to pay any price in the PX day-ahead market to schedule in advance of the ISO's real time market. Just as in the prior analysis I reconstructed the demand and supply curves used by the PX during the May through September period. In this instance I assumed that in lieu of their actual load bids, the three IOUs submitted vertical demand curves, such that they were willing to pay up to the PX administrative limit of $2,500/MWh to have their demand met in the PX DA market.[29] For this analysis I assumed that the demand bidding would be as a price taker in all hours. As noted previously, in many hours there was insufficient supply offered into the PX DA market to meet the demand at any price. Clearly the market price would have reached $2,500/MWh in those hours, as is shown in my analysis, and as depicted in the graph below, and demand would have been rationed at that price.

[29] The remaining shape in the demand bid curve is for price sensitive demand bids submitted by non-IOU PX market participants.


PX Demand and Supply With Vertical IOU Demand
Supply
Demand
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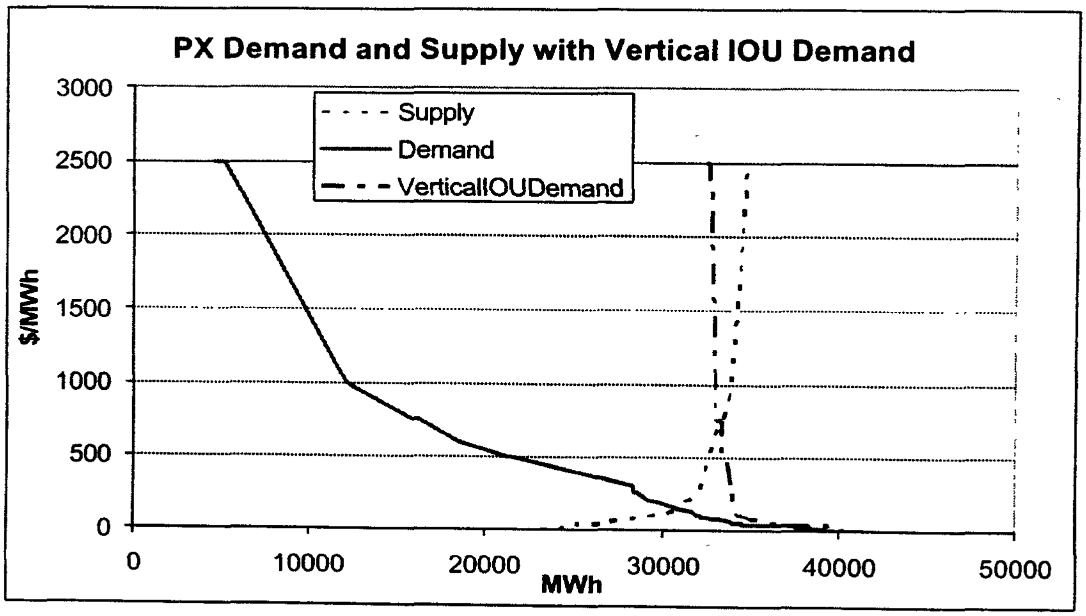
PX Demand and Supply with Vertical IOU Demand
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40000
50000
MWh

In other hours, when sufficient supply existed to clear the market, my analysis shows what would have happened to the market clearing prices and quantities in the PX DA market under such a bidding scenario. One such hour is shown in the graph above.

It is important to understand that, as I explained above, in 201 of 208 emergency hours the California market experienced during the summer of 2000, insufficient supply was offered to the PX DA market to serve demand. Thus, even if the IOUs had offered to pay $2,500/MWh for all of their demand in the PX DA market, their agreement to do so would not have eliminated underscheduling in these hours, and therefore would not have solved the ISO's reliability problems.

Q. Did you examine the financial impact of this scenario?

A. Yes. In order to do so, I examined the portfolio of the IOUs and the impact of vertical bidding on the prices paid for this portfolio. First I calculated for each hour the net position of the IOU by comparing their total demand (PX plus net ISO real time purchases) to the supply they sold in to the PX market. Then I examined the price and quantity impacts of bidding a vertical demand curve.

One such impact is that the quantity of day-ahead purchases would increase, and there would be a commensurate decrease in the real time purchases. The cost impact of this effect is determined by comparing the price paid in the PX under the vertical demand bid with the price paid in the ISO's real time market, and multiplying that difference by the increased PX DA purchases from the vertical demand bid. This provides the increased cost for those additional purchases made in the PX Day-ahead market.

In addition to this cost impact, there are additional purchases that were made in the PX market that under the vertical demand bid would be made at a higher price. The cost of this effect is simply calculated by multiplying the original short position (or long as the case may be) in the PX by the price increase due to vertical demand bidding. The sum of these two cost impacts represents the increase in buying costs from vertical demand bidding.

There is one other impact of the increased prices in the PX market from vertical demand bidding however. Because IOU supply bids have price sensitivity as well, the increased PX prices from vertical demand bidding will result in some increased sales volume from IOUs generation bids. The increased revenue from these increased sales must be subtracted from the increased costs to determine the overall impact on IOU net buying from the vertical bidding strategy. Over the May through September period, the overall cost impact on net IOU purchasing would have been an increase of $6.758 Billion. This is because the average PX price paid from the IOUs actual bids during this period was $111/MWh, which was well over twice the MMCP average for the same period, but the projected average PX price from vertical demand bidding would have been increased to $437/MWh.

Clearly the impact of vertical demand bidding, a net buying cost increase of $6.7 billion for the May through September of 2000, would have resulted in a tremendous increase and acceleration of the financial crisis that resulted in the insolvency of SCE and the bankruptcy of PG&E. Furthermore, much of this cost increase would have occurred during a period of time when SDG&E's customers would have incurred the price increases in the form of an additional quadrupling of their energy costs beyond that which resulted in so much economic disruption in San Diego. The sellers, whose withholding and gaming behavior has been demonstrated to have been the primary and predominant cause of underscheduling, argued that load bidding behavior was the cause of underscheduling and other market problems. The clearly implied solution to their expressed view of the market's problem, namely vertical demand bidding by buyers, would have further rewarded and enriched the sellers, but at an unfathomable cost to California and its economy.

IX. Summary and Conclusions on the Real Causes and Victims of Load Underscheduling

Q. What did you conclude from your analysis of underscheduling?

A. The evidence on underscheduling is clear. Substantial underscheduling occurred during 2000. The cause of the underscheduling is now also clear. It was due to the economic and physical withholding of supply by sellers of power, and the result of a plethora of manipulative games by marketers and generators. The attempt to blame the victims, the California consumers and their power purchasers, for this underscheduling is not supported by the evidence. Some of these accusations are absurd, as with Mr. Stout's attempt to argue that IOUs underscheduled so as to raise market prices. All of them are either uninformed, or worse yet, a deliberate attempt to divert attention from the malicious acts of the accusers, by pinning responsibility on the victims of the energy crisis for attempting to mitigate the gaming and market power that has so clearly been demonstrated.

The analysis demonstrates that as individual entities, the IOUs were helpless to stop the underscheduling. I have demonstrated the tremendous magnitude of supply that was withdrawn from the PX day-ahead market between 1999 and 2000. I have shown that had SCE done all that was possible on an example date of June 27, 2000, to purchase in advance of the ISO's real time market, it could barely have made a dent in the volume it ultimately had to purchase out of the ISO's real time market. I have shown that the reason load was helpless in this regard was that supply was not being offered, and certainly not being offered at competitive prices, into the PX DA market. I have shown that there has been a pattern of withdrawal of sufficient supply bids to meet forecast demand by buyers in the PX day-ahead market that dates back to 1998, and reached its acme during the summer of 2000. We cannot buy what is not offered for sale. I have shown that had the power that was offered to the market been offered at reasonable prices then there would not have existed an underscheduling problem. Instead, I have shown that thousands of MWs of power were either physically or economically withheld from the PX market, including many as a deliberate attempt to game the system through colorfully named but sinister strategies. I have shown that had the IOUs followed the path of vertical demand bidding to "correct" what has been implied by the accusations of load underscheduling, that the result would not have eliminated the ISO's real time market problem. But it would have caused unconscionable harm to the IOUs and its consumers by adding billions to their already unjust and unreasonable power costs.

Q. What should the Commission consider if sellers attempt, once again, to convince FERC that the problems in the market were caused by the nefarious underscheduling behavior of the buyers in the market, and that they, as the victims of this buying strategy, came to the IOS's aid by supplying real-time power?

A. The Commission should ask itself the following questions when considering these arguments:

- Whenever a seller says it tried to help the ISO by offering power in real time, why was that power not sold in the day-ahead market where the ISO wanted the transaction to occur?
- If load underscheduling was being used to depress prices, then why were the prices at such excessive levels, and why were the sellers making such immense profits?
- Has any evidence been presented showing instances of demand being unwilling to purchase its needed load at reasonable prices?
- When the ISO is quoted as blaming underscheduling by load for its reliability problems in real-time, does the quoted statement reflect any knowledge of what transpired in the PX day-ahead market?
- Do any quotes or representations from the ISO about load underscheduling come from the DMA that was examining market participant's behavior, or do they come from operations and management, who were looking at the size of the real-time market as their metric?
- When the PX and the PX's MSC were telling IOUs to bid a sloping demand curve, and the sellers were telling the IOUs that the buyers should be punished for doing so, whom should the buyers have believed?

The answer to these questions has been demonstrated clearly by the facts.

CALCULATIONS OF REQUESTED RELIEF

I. The California Parties' Estimate of the Magnitude of Their Proposed Relief

Q. What elements go into the California Parties' estimate of the magnitude of their proposed relief?

A. The relief from market abuse requested by the California Parties includes the following components:

- Refunds for the October 2, 2000 through June 20, 2001 period using the MMCP methodology prescribed by the Commission;
- Relief for the May 1, 2000 through October 1, 2000 using the same MMCP methodology prescribed by the Commission for refunds for the October 2, 2000 through June 20, 2001 period;
- Refunds for short term purchases made by CDWR, at the direction of the ISO, to meet IOU customer load during 2001;
- Refunds associated with ISO OOM or other purchases of duration greater than 24 hours during the October 2, 2000 through June 20, 2001 refund period;
- Refunds associated with exchange transactions through which the ISO purchased energy during the refund period of October 2, 2000 through June 20, 2001;
- Refunds and other relief associated with double payments for energy and replacement reserve in a combined amount exceeding reasonable prices,

for the period May 1, 2000 through January 1, 2001 when the double payments were eliminated; and

- Refunds and other relief for the entire May 1, 2000 through June 20, 2001 period based on Mitigated Market Clearing Prices (MMCP) calculations using the FERC Staff recommendation for natural gas prices in lieu of the reported spot gas prices previously ordered in the Proposed Findings as part of the MMCP methodology.

Q. What is the basis for these elements of relief?

A. The basis for these elements of relief has been provided in: (1) the testimony of Dr. Fox-Penner summarizing conclusions about the extensive manipulation of the market, (2) the testimonies and analyses of Drs. Carolyn Berry, Phil Hanser, and Michael Harris as well as my own testimony, and others, demonstrating analytically the significant departures from competitive market results caused by such extensive manipulation; and (3) the corroborating e-mails, tape recordings, memoranda, depositions, and other contemporaneous statements of accused sellers demonstrating their intent to manipulate markets and exercise market power. As Dr. Fox-Penner explains, the wrongful conduct of sellers, taken together, drove prices to extraordinary levels that bore no relationship to market fundamentals or to the prices that would have resulted if market rules had been followed and that it is not possible to isolate the harmful effects of any one violation or any one bad actor. Trying to sort out individually the damages caused by each single bad act would involve extended and prolonged proceedings that would serve neither the goals of the Commission or the consumers who paid excessive prices. As a result, the appropriate remedy is not to try to isolate individual transactions, but to instead apply a methodology akin to that which the Commission already ordered, but applied to additional categories of excessive prices. That is, the market-clearing prices for the period from May 2000 through June 20, 2001 should be generally reset to the level that would have occurred had the market's rules been obeyed and the market not been manipulated. The revised prices would then be applied as a cap to all transactions, and the ISO and PX would run the revised prices through their settlement systems to allocate the dollars. Such an approach provides a reasonable remedy, but one that is also feasible, as the ISO and PX know how to do these calculations, and the parties have already litigated the details of how the process should be run, and there would be no need to relitigate methodologic issues. This remedy should apply to all spot market sales in the ISO and PX, even if the seller was able to coerce the ISO into OOM sales of as much as several days or weeks or into energy exchanges rather than sales for cash. It should also apply to all short-term sales to CDWR/CERS – sales in which CDWR/CERS was essentially standing in the shoes of the ISO or defunct PX, and which frequently involved in-state sellers (who could have been compelled to sell available power to the ISO) exporting out-of-state to sellers who then sold to CERS. Below I provide an estimate of the remedy that would flow from such calculations. This is just an estimate, and I recommend that the ISO and PX be ordered to actually carry out the detailed calculations as part of a compliance process.

Q. Would such a calculation provide a full and complete remedy for the manipulation that has been identified?

A. No. The California Parties' analysis proves that the various strategies used by the sellers left a significant quantity of economic generation off-line during high priced periods. The MMCP methodology assumes that a competitive market would have cleared at the marginal cost of the least efficient unit running – but if more efficient units were not running, then the MMCP methodology will overstate the competitive result. A better analysis would rerun the MMCPs using a least cost dispatch so as to achieve costs that better represent a competitive result.

Q. Do you recommend that the MMCPs be recalculated using a least cost dispatch?

A. While I believe that would yield a more accurate result, and increase the remedy to buyers, I recognize that this would also lead to substantial litigation, as different parties fight over which least cost dispatch is accurate. In the interests of bringing this litigation to a close in a reasonable yet feasible manner, I recommend that MMCPs be based on the marginal cost of the units actually dispatched in the BEEP stack (as per the current MMCP calculation) rather than revising the MMCPs to incorporate a least cost dispatch element.

II. Relief for the May 1, 2000 through October 1, 2000 Period

A. Development of Mitigated Market Clearing Prices

Q. How have the California Parties developed an estimated set of mitigated prices for the May 1, 2000 through October 1, 2000 period?

A. The basic approach used to develop mitigated prices parallels, to the extent possible, the

MMCP methodology adopted in Judge Birchman's Proposed Findings on refunds.[30] The data availability and data form associated with the May 1, 2000 through October 1, 2000 period differed somewhat from the October 2, 2000 through June 20, 2001 period for which Judge Birchman defined MMCPs in the Proposed Findings. The following restrictions describe the differences in data availability for this earlier period.

- January 1- May 31, 2000: Hourly instructions and hourly settlement information is available for the ISO real-time market.
- June 1 – August 31, 2000: 10 minute instructions and hourly settlement information is available for the ISO real-time market.
- After September 1, 2000: 10 minute instructions and 10 minute settlement data is available for the ISO real-time market.

The California Parties used the most detailed information available for each of these time periods to calculate MMCPs. The basic methodology for calculating MMCPs was to look at those units that bid into and were dispatched in the ISO real-time market, and that followed their dispatch instructions (at a threshold of at least moving output 0.1 MW as established in the Proposed Findings). The heat rates for these units dispatched were multiplied by the relevant gas price (depending on whether the unit was located in Northern or Southern California), and the most costly of these units was selected as the marginal unit. Six dollars per MWh of variable O&M costs was added to the energy cost to determine the total incremental cost of the marginal unit for each interval. The MMCP

[30] *San Diego Gas & Elec. Co., Certification of Proposed Findings on California Refund Liability*, 101 FERC ¶ 63,026 (2002) ("Proposed Findings").

was set at this incremental cost. For the pre-October refund calculations the gas price was established using the same methodology as established in the current FERC MMCP methodology and the Proposed Findings.[31] During the Phase 1 refund hearings, one of the questions at issue was whether certain units used gas fuel or another fuel source, as only units burning gas fuel were eligible to set the MMCP. Since data on fuel type was not available for the pre-October 2000 period, all units that were identified as gas burning were assumed to have only burned gas, and were considered eligible to set the MMCP in all intervals they were dispatched.

Q. What were the results of the MMCP determination?

A. The results of the MMCP determination were as follows:

<u>Average Prices May 1 through October 1, 2000</u>

	($/MWh)
Market Clearing Price PX Day-Ahead Market (SP15)	106.15
Market Clearing Price PX Day-Ahead Market (NP15)	101.74
Market Clearing Price ISO Real-time Market (SP15)	135.13
Market Clearing Price ISO Real-time Market (NP15)	115.74
Mitigated Market Clearing Price	49.18

[31] There are no significant differences between the spot gas price index approach and the FERC Staff Recommended approach for gas prices in the MMCP index during the pre-October period, as the California spot gas price index had not substantially disconnected from actual incremental gas costs or other indices during this period. I calculated the refund for the May through October period using the FERC Staff Recommended gas price approach, and found only a $30 million difference out of more than $2 billion in total refunds (the Staff approach resulted in a reduction in refunds of $30 million for this period).

B. Relief Calculations Based on the MMCPs Determined for the Period Before October 2, 2000

Q. Please explain the California Parties' calculation of a remedy based on the MMCPs determined for the period before October 2, 2000.

A. Although MMCP data was calculated and available for the entire January 1, 2000 through October 1, 2000 period, consistent with our contemporaneous market observations, I found no significant difference between prices as determined by the MMCP and actual observed prices in the energy markets during the period January 1, 2000 to May 1, 2000. While many of the manipulate games were used in that period, I believe that they tended to have more particularized and isolated impacts prior to May 2000. However, beginning in May 2000, the manipulative games and market power exercises described in the California Parties' testimony (*e.g.*, the testimonies of Dr. Peter Fox-Penner and Dr. Carolyn Berry) became pervasive, with a broad influence on market prices paid by buyers and to sellers in all or most hours. As such I have calculated proposed relief estimates for the period after May 1, 2000.

Since the purpose of these refund estimates is to establish a general magnitude of proposed relief consistent with the California Parties' request for relief, and because the full complement of necessary data was not available, these refund estimates are developed only on an aggregate basis and cannot be decomposed into who owes what, and who is owed what, and therefore it is not possible for me to provide estimates to who owes what to whom based on these calculations.

Refund calculation estimates for the PX market were made, as prescribed in the Proposed Findings, excluding the PX day ahead volumes, that match with BFM purchases, consistent with Judge Birchman's ruling on that issue in the Refund Proceeding. The data was not available to extract individual buyer and seller volumes from the PX day-ahead market transactions, however, so the BFM volumes were removed from the refund estimates by calculating the entire magnitude of refund associated with BFM purchases by buyers and removing this refund estimate from the total PX refund calculation. As such, this refund estimate will be reduced compared to the Proposed Findings methodology to the extent some sellers elected not to deliver the entirety of their BFM sales through the PX day-ahead market. (The California Parties put on a substantial case before Judge Birchman to show that BFM volumes should not be subtracted from PX day-ahead volumes at all. They continue to support that position, but rather than relitigating the issue here, they will rely on the materials already submitted on that issue.)

For the ISO markets, the refund calculation was completed using hourly settlement information for the period May 1, 2000 through August 31, 2000. From September 1, 2000 through October 1, 2000, ten-minute settlement information was used for the refund estimates. Since the settlement level detailed data was not available for the pre-October, 2000 period, the methodology used to calculate refunds from MMCP and MCP data differed somewhat from the Proposed Findings approach. The ISO provided datasets including volumes of instructed and uninstructed energy as well as ancillary services. The net buying position of the IOUs in these markets was used as the volume to which the difference between MMCP and MCP was applied (the MMCP as a cap, as in the Proposed Findings). Thus, a complete settlement rerun including the additional refund implications on other ISO accounts was not possible for the pre-October calculations. Again we did not have the ability to disaggregate to individual buyers and sellers.

The results of the analysis of refunds for the May 1, 2000 through October 1, 2000 period are as follows:

<u>Refunds for May 1, 2000 through October 1, 2000</u>

	($million)
PX Markets (Day-ahead and Hour-ahead)	$ 368
ISO Real-time Energy Market	$ 1,484
ISO Ancillary Service Markets	$ 522
Total	$ 2,374

III. Refunds for CDWR's Short-Term Purchases to Serve California Customers' Load

Q. Have the California Parties included any category of CDWR purchases in their refund calculations?

A. CDWR's participation (through its scheduling arm, CERS) in the ISO market took four basic forms: (1) real-time market purchases from the ISO to meet IOU load shortfalls which have been found to be subject to mitigation in the FERC refund proceeding; (2) long–term power purchase contracts which were scheduled with the IOUs to meet customers load, and which were not found by FERC to be subject to refund, nor are they included as a component of the California Parties' relief request; (3) short-term CDWR purchases at the request of the ISO to meet IOU load, and scheduled to the ISO as OOM purchases by the ISO from CDWR, and (4) short term purchases made by CERS to meet

IOUs' load that was scheduled with the IOUs to meet their load, and therefore did not appear in the ISO data as transactions, even though they were short term purchases CERS made in lieu of the ISO or PX. FERC has previously determined that the third and fourth category of transactions are not eligible for refund. For the reasons specified in Dr. Fox-Penner's overview testimony, the William Green testimony, and the California Parties' pleading, the California Parties are seeking refunds associated with the costs of both categories. However, I have not acquired the data on the fourth category of costs described above, though I understand the magnitude of costs associated with these exceeded $2.7 billion. The average price for these transactions was well over $200, well in excess of the MMCPs for this period. I expect that the magnitude of costs above the MMCP for these transactions would be substantial but it is not included in my refund calculations below.

Q. How have the California Parties calculated the refund amounts associated with the CDWR short-term purchases?

A. In order to calculate the refunds associated with CDWR's short-term purchases, we simply compared the actual prices paid associated with these short-term CERS transaction, based on ISO supplied data, with the MMCPs. When the MMCPs were lower than the actual prices paid, the refund was calculated as the difference in price times the volume of the transaction.

Q. What is the amount of the additional refund that the California Parties claim with respect to CDWR short-term purchases?

A. The additional refund associated with CDWR's short-term purchases is $1.263 Billion.

IV. Refunds for ISO OOM and Other Transactions Exceeding 24 Hours

Q. Have the California Parties included transactions exceeding 24 hours in duration in their refund calculations?

A. Yes. During the refund period (*i.e.*, October 2, 2000 through June 20, 2001), the ISO engaged in a number of OOM purchases whose duration exceeded 24 hours. FERC concluded that transactions of length exceeding 24 hours, or transactions made more than 24 hours prior to delivery, were not subject to refund. For the reasons specified in Dr. Fox-Penner's overview testimony and the California Parties' pleading in this case, the California Parties are seeking refunds associated with the costs of these ISO purchases with durations exceeding 24 hours.

Q. How did the California Parties identify transactions of greater that 24 hours in duration that were eligible for refund?

A. Because transactions of length greater than 24 hours, or transactions made more than 24 hours prior to delivery were found by FERC not to be subject to refund, the selling parties whose transactions fell into this category requested that their specific qualifying transaction be excluded from the Phase 2 refund calculations. As such, they identified each such transaction that they contended should be exempt from refunds. The Proposed Findings established which of this set of transactions claimed by sellers as exempt from refunds, actually were subject to refund (*i.e.*, which transactions were for periods less than 24 hours and entered into within 24 hours of delivery). Those transactions sellers requested be exempted which were, in fact, exempted, make up the set of transaction from which California Parties seek refunds. (The California Parties have disagreed with some of the findings concerning whether particular transactions were for a period longer than 24 hours. We will not reargue that issue as it is already briefed to the Commission – for this estimate I assume that Judge Birchman properly determined which transactions fall into the longer than 24 hour OOM sales to the ISO category.)

Q. How did you calculate refunds for transactions exceeding 24 hours in duration?

A. In order to calculate the refunds associated with transactions previously exempted from refunds for the aforementioned reasons, for which California Parties now seek relief in the form of refunds, we applied the MMCPs consistent with the Proposed Findings. I estimated through these calculations that the refunds for transactions exceeding 24 hours in duration, or for delivery over a period exceeding 24 hours through the ISO, totaled $54.5 million.

V. Refunds Associated With Exchange Transactions

Q. How did you calculate the refunds or relief associated with Exchange transactions?

A. For exchange transactions I estimated the value of the relief request by comparing the value of the power received by the ISO to the value of the power returned by the ISO, and I calculated the relief request as the difference between these two values. I used the MMCP estimated for the time period the power was received multiplied by the volume of the power received under exchange transactions as the measure of value received. I also used the MMCP estimated for the time period of the returns, multiplied by the volume of power returned under the exchange transactions as the measure of the value of returned energy. I estimated the resulting refund associated with exchange transactions to be $101.5 million.

VI. Refunds and Other Relief Associated with Joint Payments for Replacement Reserves and Real-Time Energy

Q. On what basis do the California Parties claim refunds or other relief for joint paymens for replacement reserves and real-time energy?

A. During the May 1, 2000 through June 20, 2001 period there were many hours in which sellers of replacement reserve power were dispatched to provide energy to meet the needs of the ISO's real-time market. This created the potential for a payment at times as high as twice the ISO's real-time market cap. In fact, during June of 2000, thousands of MWs of replacement reserve was procured during many hours, the majority of which was also dispatched to provide real-time energy. The caps for both the replacement reserve market and the ISO real-time market were $750/MWh during June of 2000, so that revenues reaching $1,500/MWh were obtained for thousands of MWh of production. The desire to receive these extreme payments for what is often referred to as "double dipping" or "double selling" provided the motivation for the supply underscheduling and physical and economic withholding practices that have been described in other testimonies such as Dr. Carolyn Berry's, and my testimony on supply bidding and underscheduling. Although the refund calculations described in Section II above capture the above MMCP payment for replacement reserve, as well as those for energy, the potential for this unreasonable double payment must also be mitigated to provide appropriate relief from the market manipulation used to achieve these double payments.

Q. How did you calculate refunds and other relief associated with double payment for replacement reserve and real-time energy?

A. In order to calculate the refunds and other relief associated with this double payment I took the following steps. First, I looked at those units that were awarded capacity bids for replacement reserves. For this set of units, I looked at the energy dispatch from the real time market.[32] I then established the volume associated with double payment based on the minimum of the capacity award and the energy dispatched from the ancillary service. Given this volume, I then calculated the incremental refund associated with double payments as the difference between the refund from comparing the sum of the real-time energy and replacement reserve price to the MMCP, and the sum of the individual refunds calculated from comparing the real-time energy price to the MMCP and the replacement reserve price to the MMCP. Algebraically, this can be summarized as follows:

P(RT) = Price for real-time energy

P(RR) = Price for replacement reserve

Q = minimum of energy sold in real-time and replacement reserve awarded

Refund calculation = Q * (Max(P(RT) + P(RR) – MMCP, 0) –
Q * ((Max(P(RT)-MMCP,0) + Max(P(RR)-MMCP,0)

The results of these calculations were:

Refunds or Other Relief from Mitigation of Double Payments
for Replacement Reserves and Real-time Energy

($million)

[32] For the period May through August the ISO data did not provide any information that distinguished the specific ancillary service for which the real-time energy dispatch was associated. If the unit sold replacement reserves and also was dispatched in the real-time market from its ancillary services award, I assumed that this dispatch was associated with replacement reserves.

May 1-October 1, 2000	$135
October 2, 2000 – June 20, 2001	$121
Total	$256

VII. Additional Refunds from the Use of the FERC Staff's Recommended Gas Price

Q. Have the California Parties calculated additional refunds based on the FERC Staff's recommended gas price?

A. On August 13, 2002, FERC Staff issued a recommendation regarding the use of spot natural gas prices for the purpose of calculating refunds from sellers.[33] Staff identified several reasons why the California border indexed gas prices should not be relied upon for the purpose of calculating MMCPs for refunds. In addition to the evidence put forth by FERC Staff, the California Parties presented evidence on October 15, 2002, supporting the Staff conclusion and recommendation, with proposed refinements, for the treatment of gas prices in refund calculations. Further evidence has emerged since October 15, 2002, reinforcing Staff and California Parties' conclusion that California border spot gas indices cannot be relied upon for the purpose of refund calculations. That additional evidence is presented in the testimony of Dr. Harris, Exh. No. CA-15.

The California Parties seek relief in the form of refunds or other relief for different components of overcharges as noted in Sections II -VI of this testimony. Although there were episodic increases in gas costs beginning in the Summer of 2000,

[33] *See Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies,* Docket No. PA02-2-000.

most of the evidence of manipulation, such as wash trades, appears to have occurred primarily during the period that FERC has previously determined was subject to refund: October 2, 2000 through June 20, 2001. The Proposed Findings estimate the refund liability during this period at about $1.8 billion. That calculation was based on MMCPs calculated from spot gas price indices. Using gas price data consistent with the FERC Staff recommendation provided to me by Dr. Harris, I have recalculated MMCPs.

The MMCPs I have calculated using the Staff recommendation for gas prices have been applied to all of the transactions for which California Parties are seeking relief in the form of refunds during the October 2, 2000 through June, 2001 period.[34] These include the transactions found to be subject to refund in the Proposed Findings, plus those transactions associated with CDWR short term purchases described in Section III above, and those transactions associated with OOM transactions greater than 24 hours described in Section IV above. The same methodology for calculating refunds from various transactions was used as had been used for the aforementioned refund calculations. For the refund period ISO energy and ancillary service charges, the process was equivalent to that use during the pre-October calculations described in Section II.B. For the PX refunds, the same approach used by the PX to calculate refunds was used. This process was fully described by the PX in Phase II of the refund proceeding, and was approved in

[34] I have also performed a calculation using the FERC Staff recommended gas prices for refund calculations in the May through October period. I found only a small difference in requested relief of about $30 million in reduced refund associated with the FERC Staff recommendation during this period. If it is determined that the spot gas price indices were not reliable during the May through October 1, 2000 period, then the relief request associated with FERC Staff recommended gas prices should be reduced by $30 million.

the Proposed Findings. The MMCP results are presented below.

Average MMCP Calculations For October 2, 2000 – June 20, 2001

	($/MWh)
Spot Gas (Proposed Findings)	179.63
FERC Staff Recommendation	93.26

Using these revised MMCPs I have calculated the increased refund that is due to the use of the FERC Staff recommended gas prices for each of the categories of refund described previously, associated with the October 2, 2000 through June 20, 2001 period. These are shown below:

Additional Refunds From FERC Staff Recommended Natural Gas Prices

	($million)
PX Markets (Day-ahead and Hour-ahead)	$ 76
ISO Real-time Energy Market	$708
ISO Ancillary Service Markets	$153
CDWR Short-term Purchases	$749
Transactions Greater Than 24 Hours	$75.5
Exchange Transactions	$ (49.5)
Double Payment (RR and RT energy)	$25
Total	$ 1,737

VIII. Summary of Requested Relief

Q. Please summarize the total additional relief requested by the California Parties.

A. The components of additional requested relief, as described in the previous sections of this testimony, are summarized below:

Total Relief Requested by the California Parties

	($million)
PX Markets (Day-ahead and Hour-ahead)	$ 368
ISO Real-time Energy Market	$1,484
ISO Ancillary Service Markets	$ 522
CDWR Short-term Purchases[35]	$1,263
Transactions Greater Than 24 Hours	$ 54.5
Exchange Transactions	$101.5
Double Payment (RR and RT energy)	$256
FERC Staff Natural Gas Prices	$1,737
Total	$5,786

This $5.7 billion is in addition to the approximately $1.8 billion determined by Judge Birchman, resulting in estimated total relief of over $7.5 billion.

Q. Is the methodology used by the California Parties consistent with that adopted by FERC in the refund proceedings?

A. The methodology to calculate the above estimates is the approach FERC has already approved for establishing the level of payment above reasonable costs that should be refunded to buyers in the Proposed Findings for refunds. For the pre-October 2, 2000 period, there is no need to conduct extensive hearings on how a remedy should be calculated – we already know how to run this MMCP methodology. The remedy for the pre-October 2, 2000 period, estimated here at $2.3 billion should only be subject to final

[35] As noted previously, there is a category of CDWR short-term purchase costs associated with power scheduled directly with the IOUs that has not been included in this estimate. The relief should be substantially larger as a result.

calculation in an ISO/PX compliance process, and FERC review. The same holds true for the over $1.2 billion in excessive costs paid by CDWR in transactions that occurred during the post-October 2, 2000 period that FERC has already established as subject to refund.

The remaining categories for which relief is sought include OOM sales to the ISO of greater than 24 hours and exchange transactions. These types of transactions were used by sellers to try to prevent their excessively priced power from being subject to refund, while these same selling entities were engaged in the market abuse practices described in the various other testimonies of the California Parties. By excluding these transaction from refunds, FERC would once again be sending an incredibly dangerous signal to the electricity markets: if you plan to manipulate an electricity market, or take advantage of one that is being manipulated, insist on transactions that are either greater than 24 hours, or demand payment in-kind, because there will be *no penalty* for abuse in these forums.

The next category of costs relief which the California Parties seek is for double payment of replacement reserve and real-time energy. Many market participants abused the market to gain access to these double payments. To limit refunds to mitigation of each market individually will allow these types of withholding abuses to be rewarded. And finally, there is the gas price to be used in determining relief for market abuse. Clear evidence has been presented in Dr. Harris' testimony, and elsewhere, including the FERC Staff's own report, and the California Parties' October 15, 2002 filing on these issues. If the FERC allows the sellers to reap the electricity market benefit from these gas market abuses, then FERC should allow for recovery of the $1.7 billion in excess costs in the electricity markets from the use of spot gas prices that were manipulated from those who manipulated the gas markets.

Q. Does this conclude your testimony?

A. Yes.

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 GARY A. STERN

I declare under penalty of perjury that the foregoing is true and correct.

Executed on February 24, 2003.

Gary A. Stern

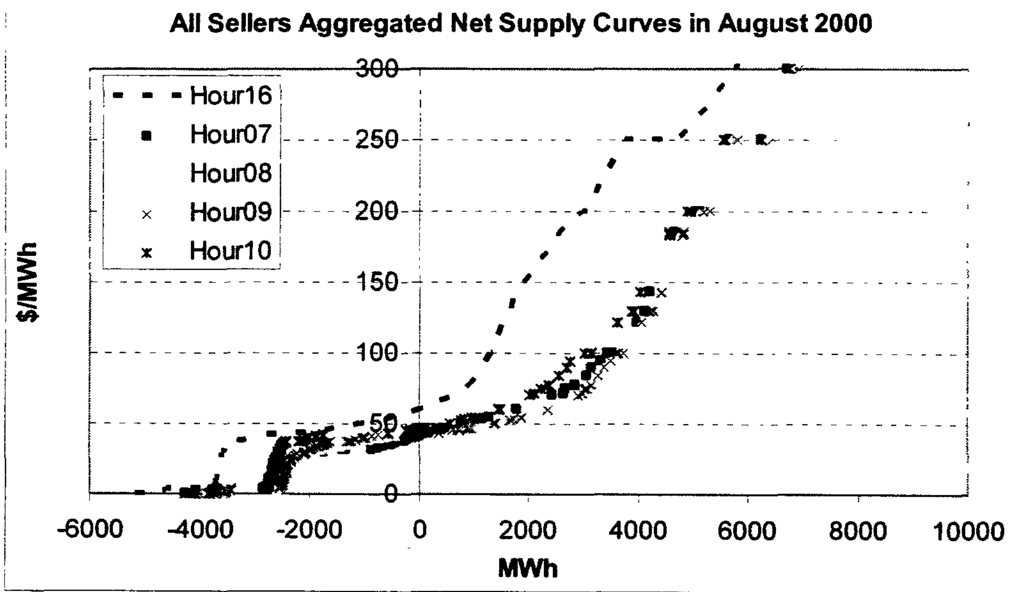
Gary A. Stern

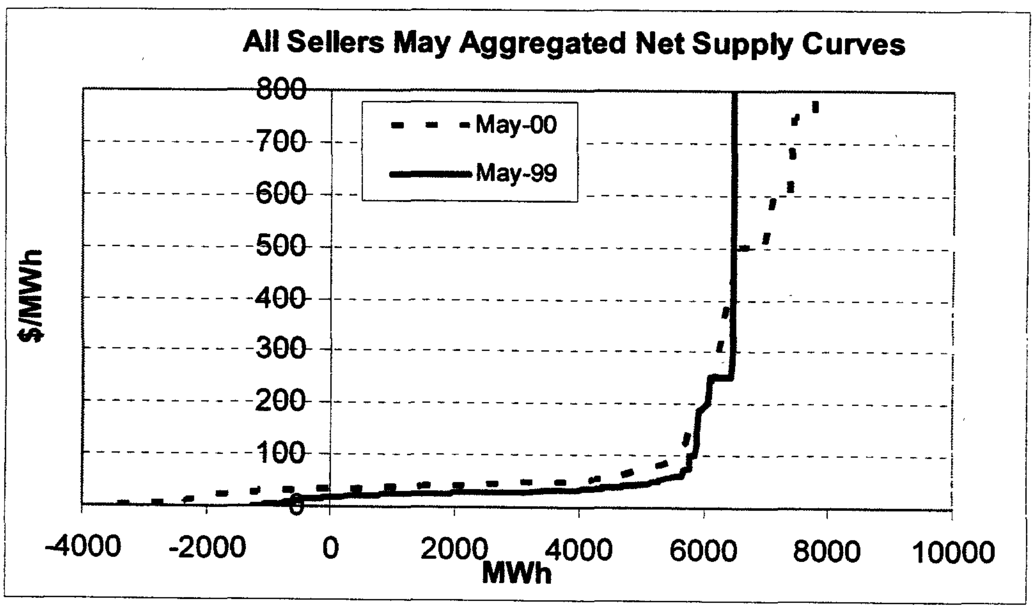
Index of Relevant Material Template

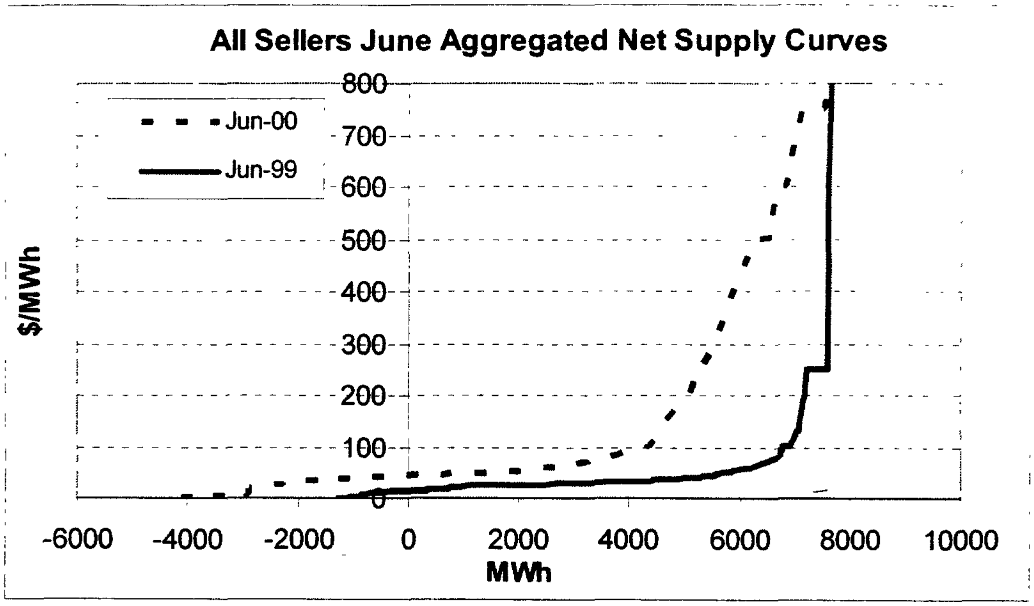
Submitter (Party Name)	California Parties
Index Exh. No.	CA-4
Privileged Info (Yes/No)	Yes
Document Title	Appendix A to Prepared Testimony of Dr. Gary A. Stern on Behalf of the California Parties
Document Author	Dr. Gary A. Stern
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	Sellers withheld from the market. Seller withholding and other market manipulation, not buyer underscheduling, led to forced reliance on the Real-Time Market. Prices in the ISO and PX Spot Markets from October 2, 2000 to June 20, 2001 were unjust and unreasonable. Prices before October 2, 2000 were not consistent with Sellers' market-based rate tariffs and those of the ISO and PX.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001; c) after 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95 and EL00-98 (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	Comparison of the net supply curves for May – September 1999 and May – September 2000 for All Sellers and subsets of sellers that included Duke, Dynegy, Reliant, Powerex, Mirant, Williams, MIECO and Other Sellers showing that, in 2000 compared to 1999, there was a systematic withdrawal of supply from the PX Day-Ahead market through both physical and economic withholding by most of the selling entities examined.
Party/Parties performing any alleged manipulation	All Sellers

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

APPENDIX A: FULL SET OF GRAPHS USED IN SUPPLY BIDDING ANALYSIS



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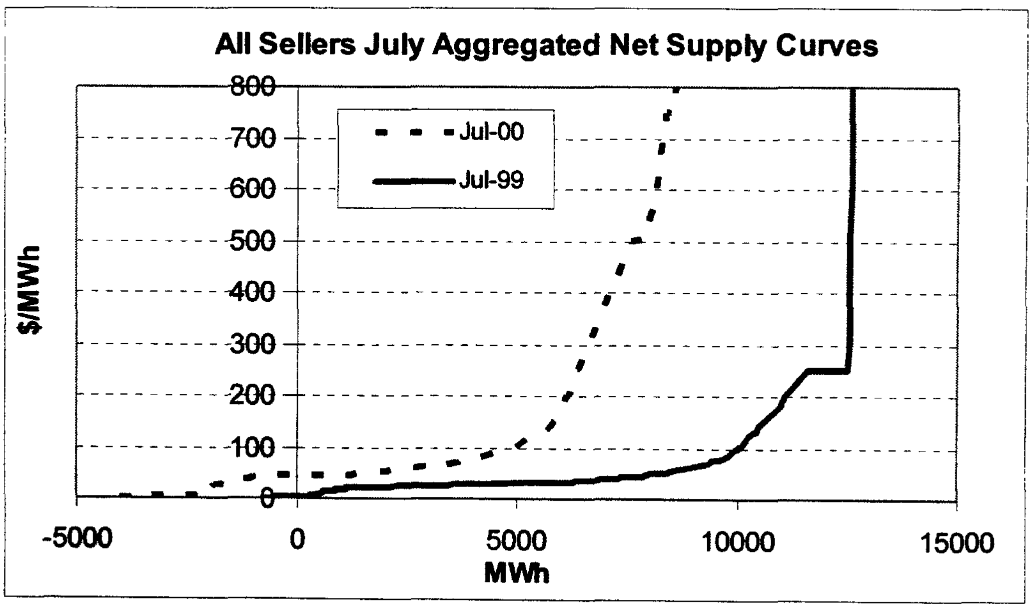
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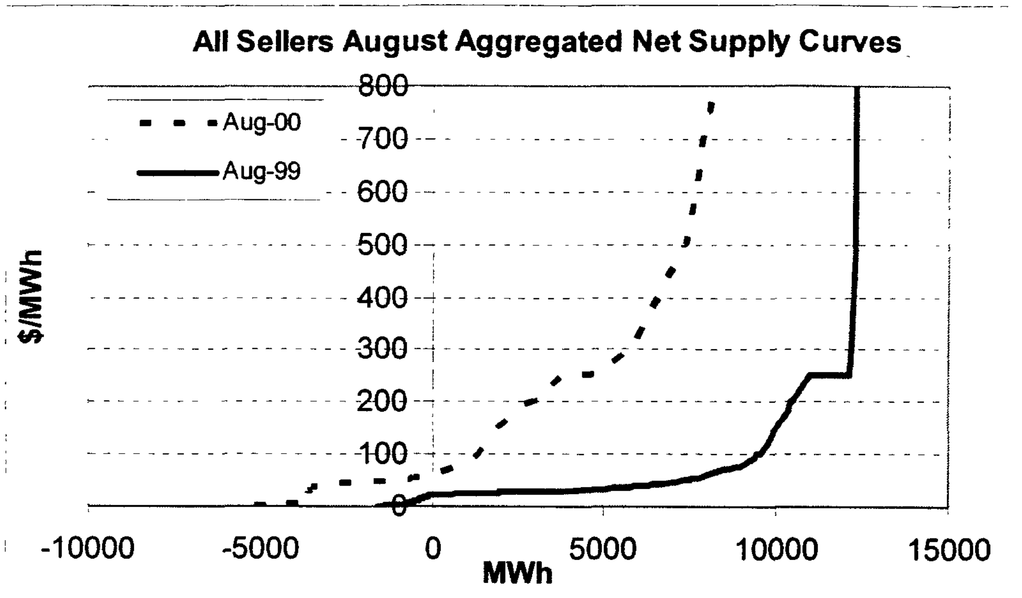
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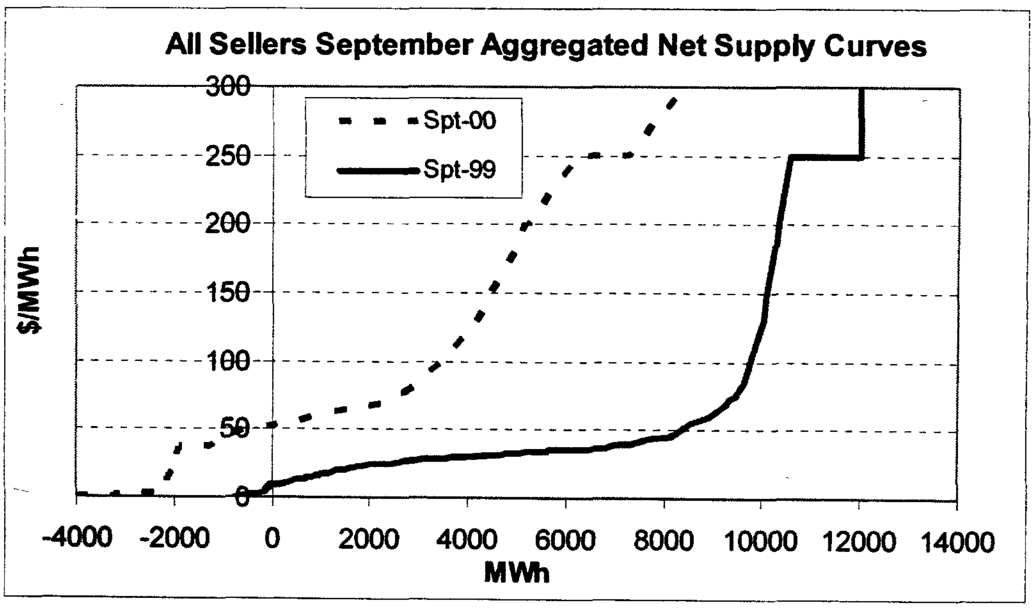
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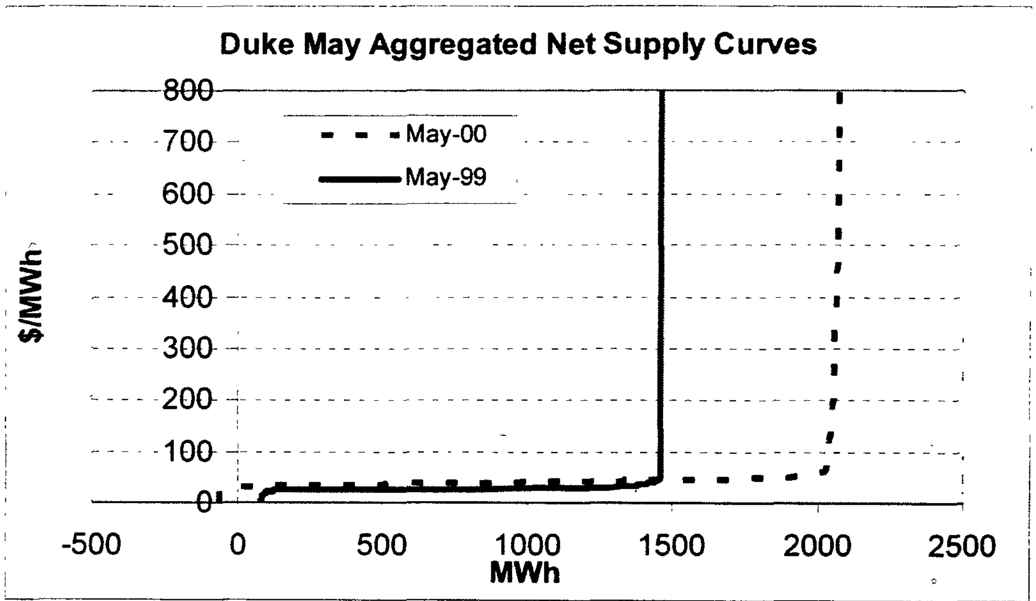
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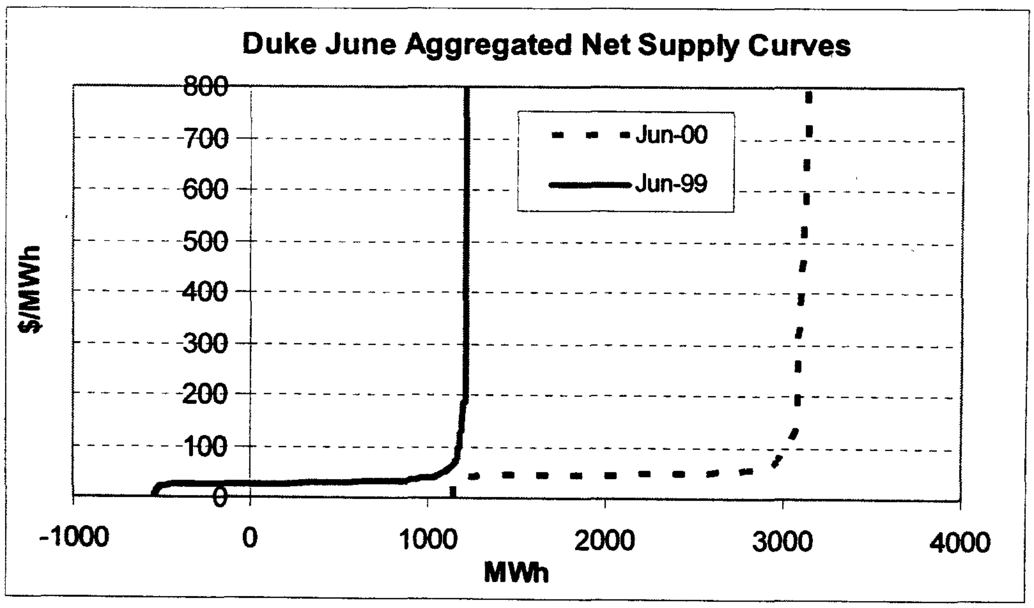
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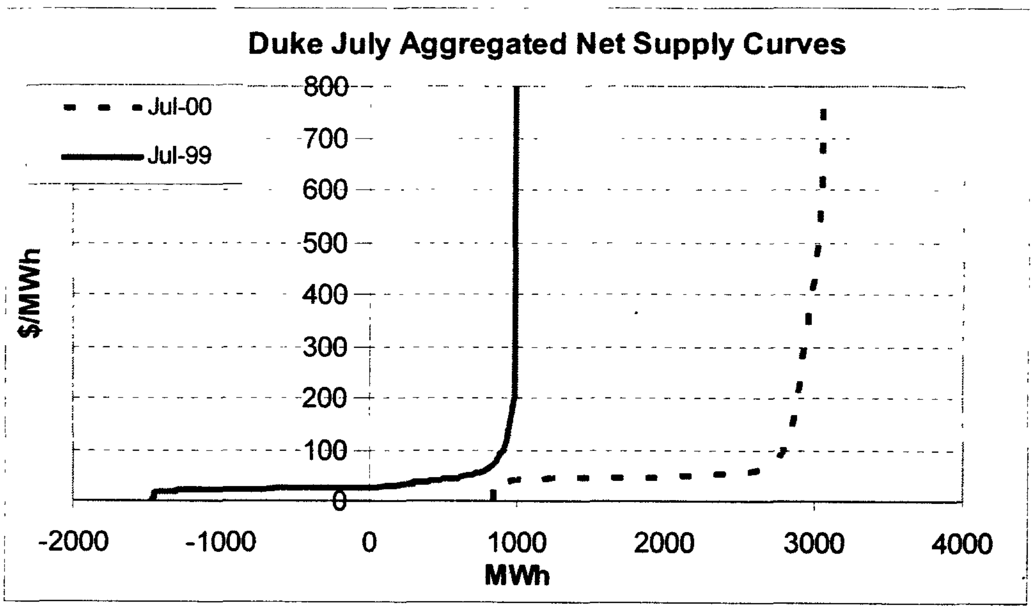
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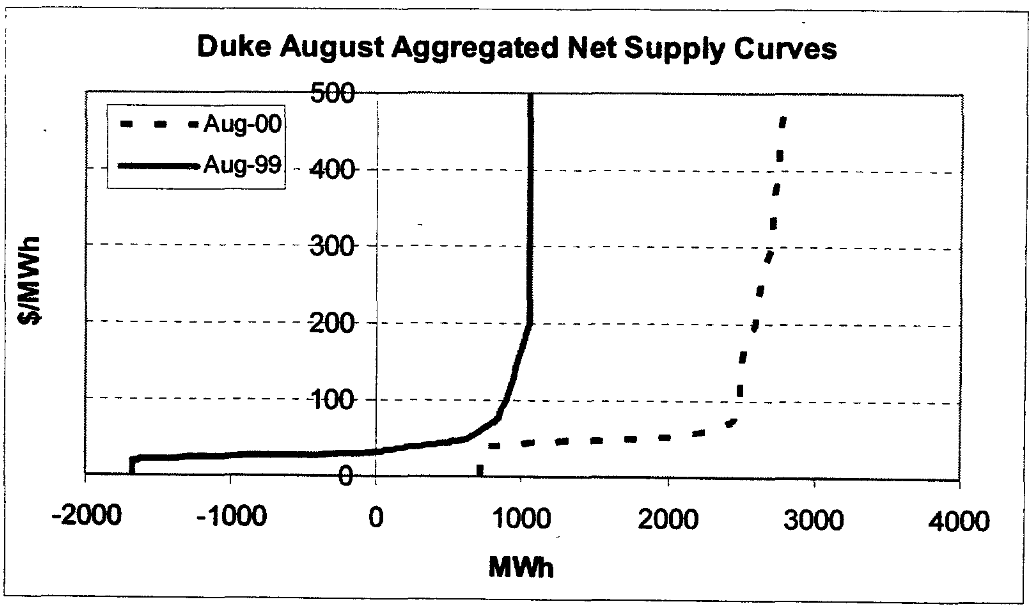
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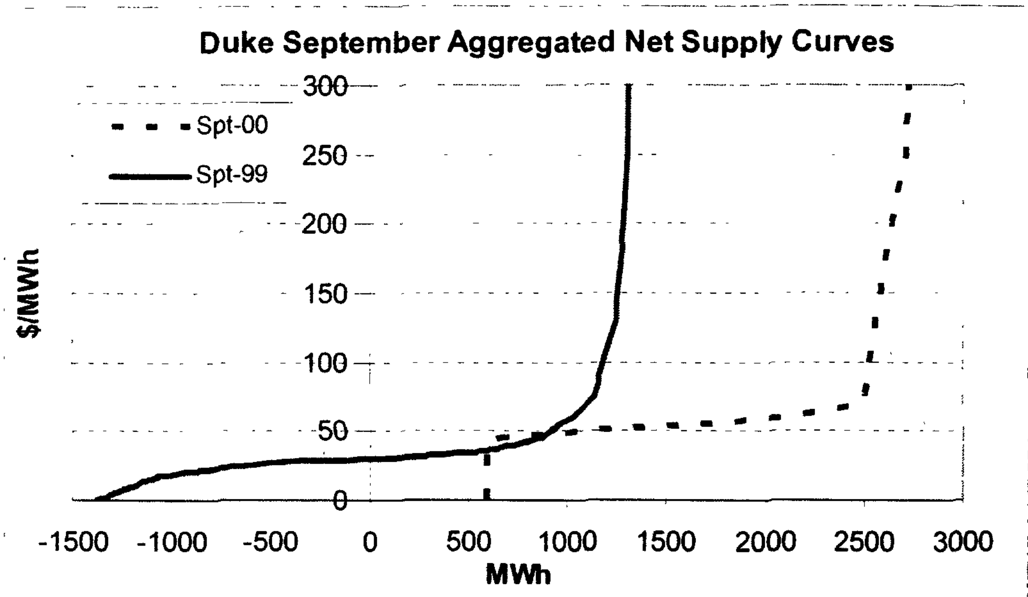
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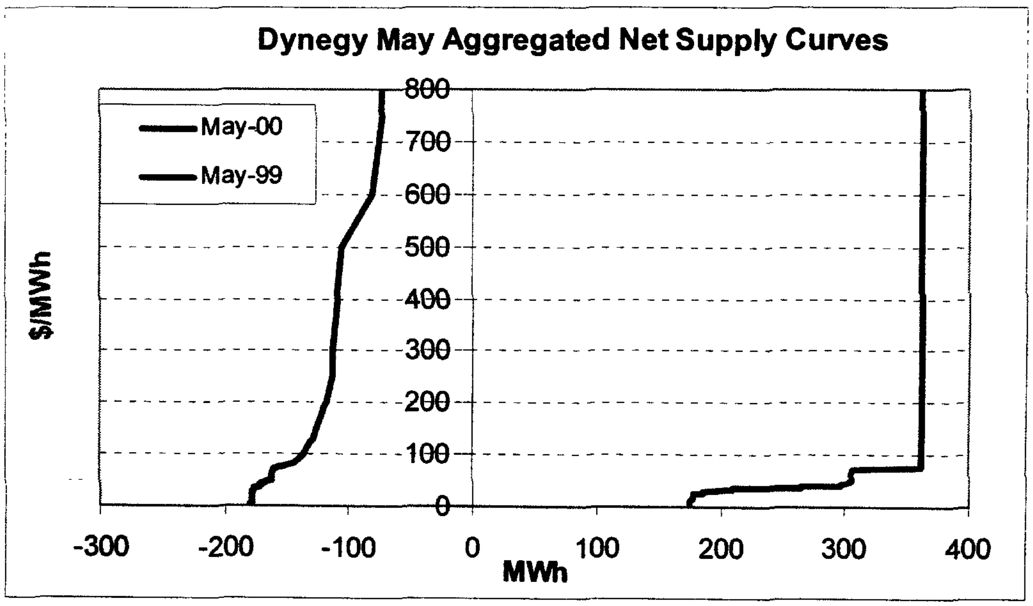
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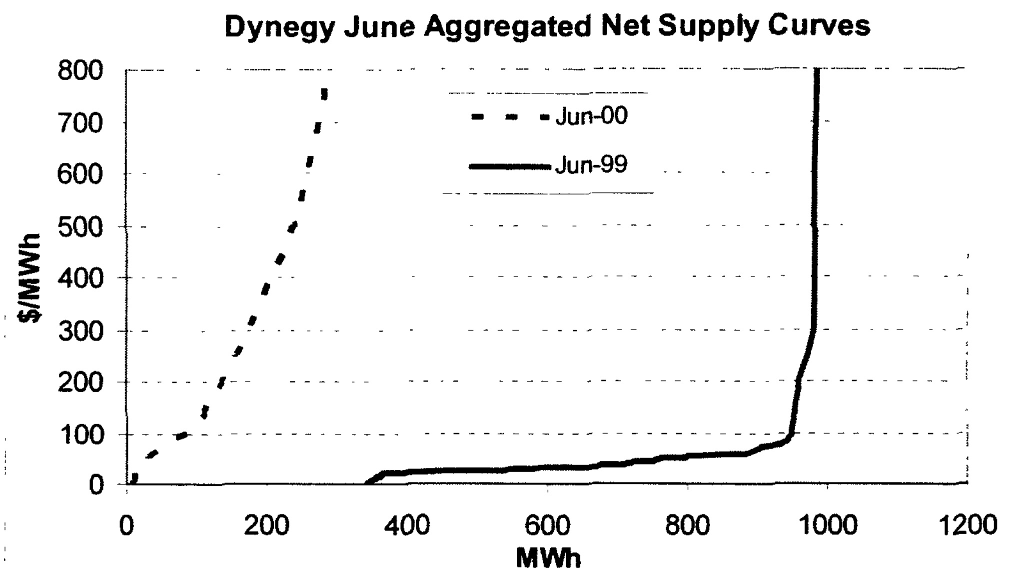
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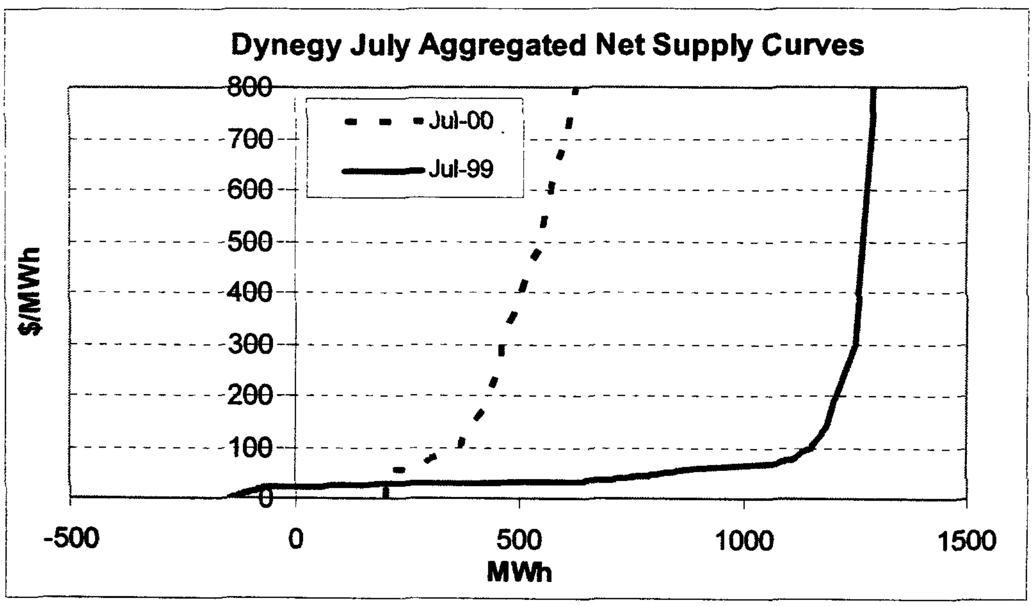
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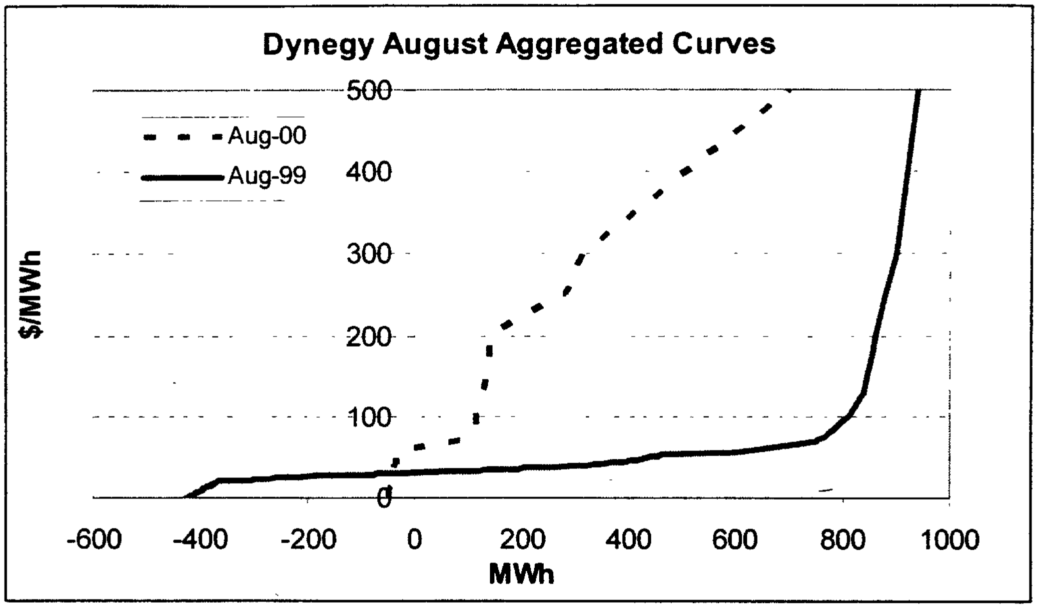
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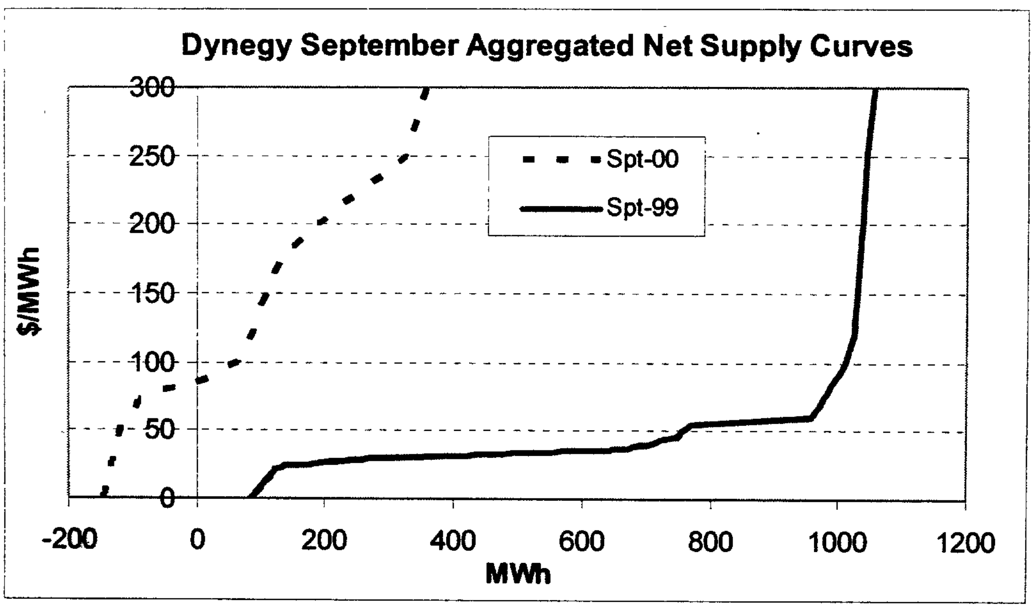
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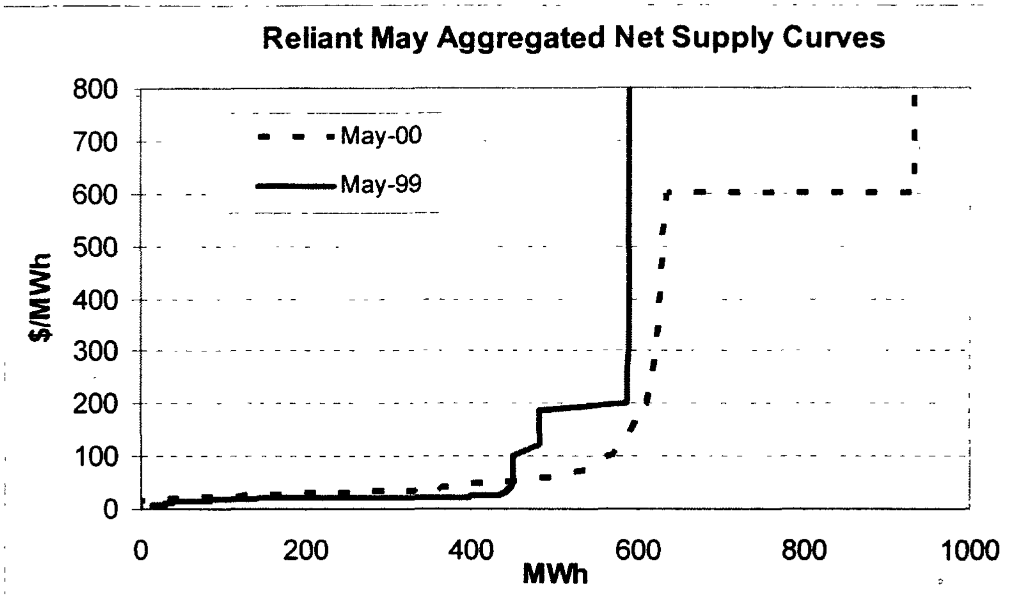
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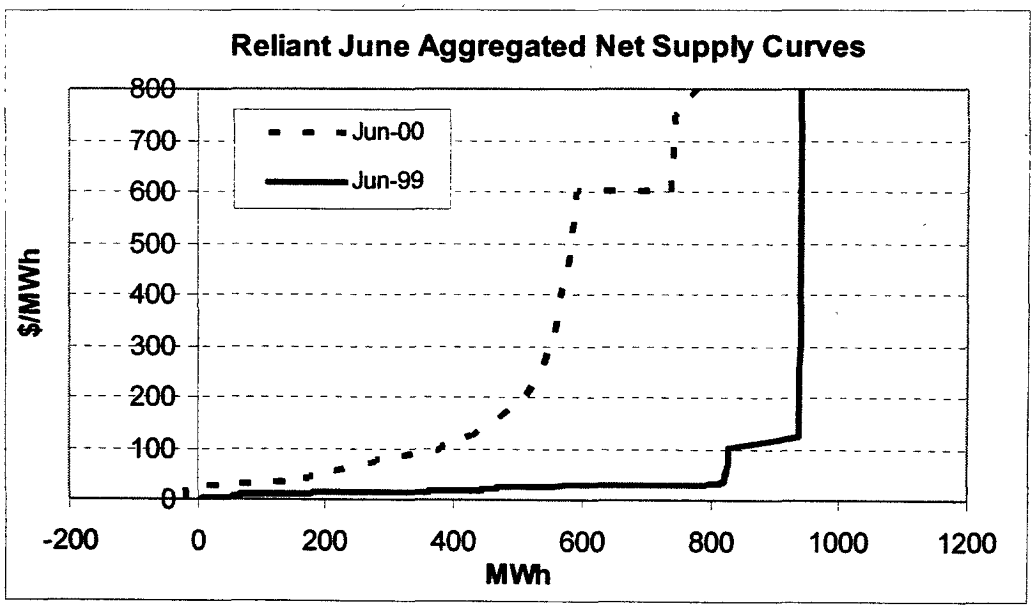
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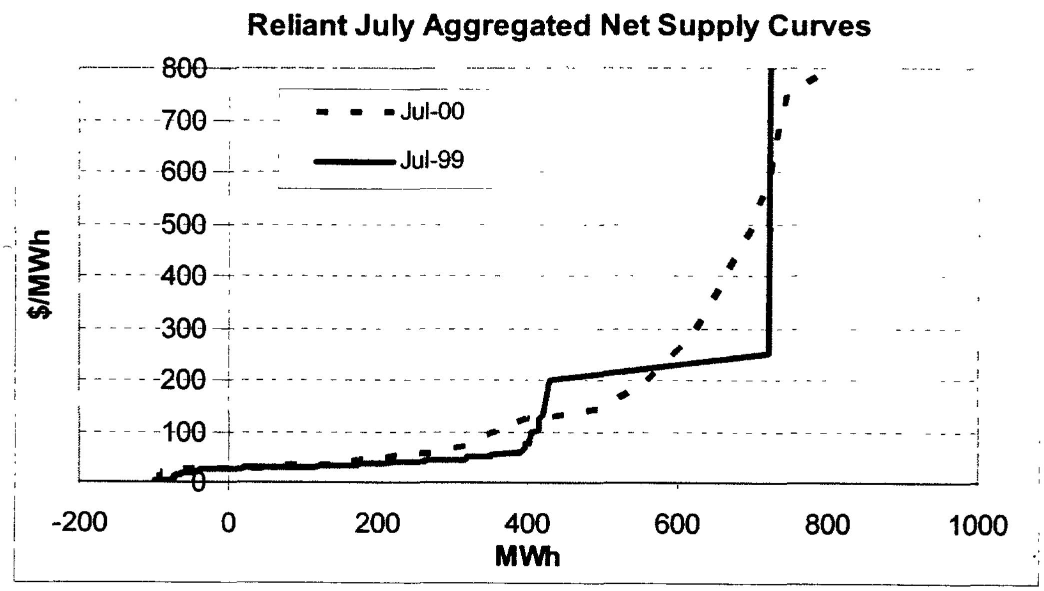
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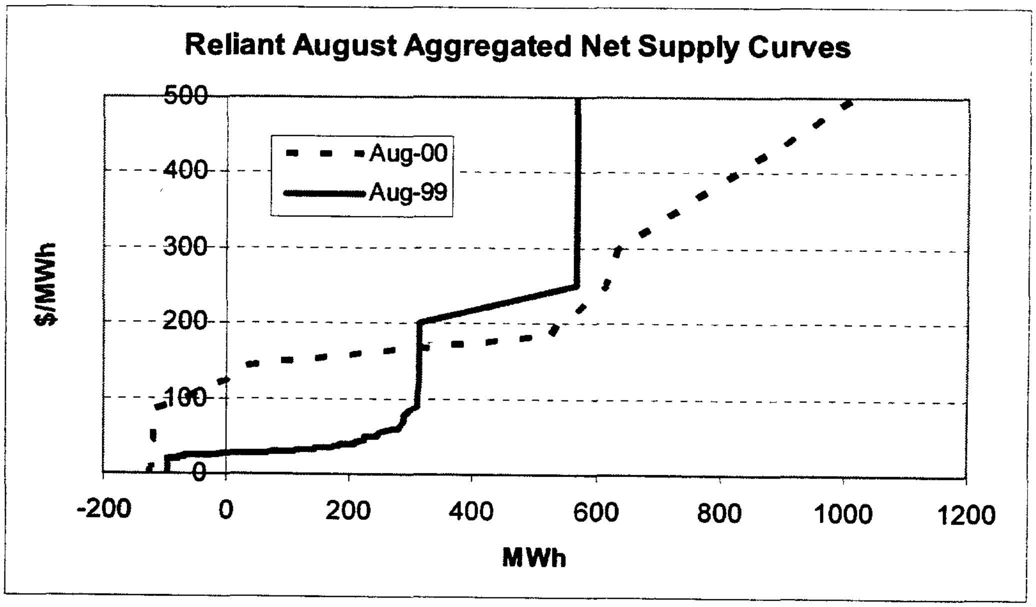
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MWh

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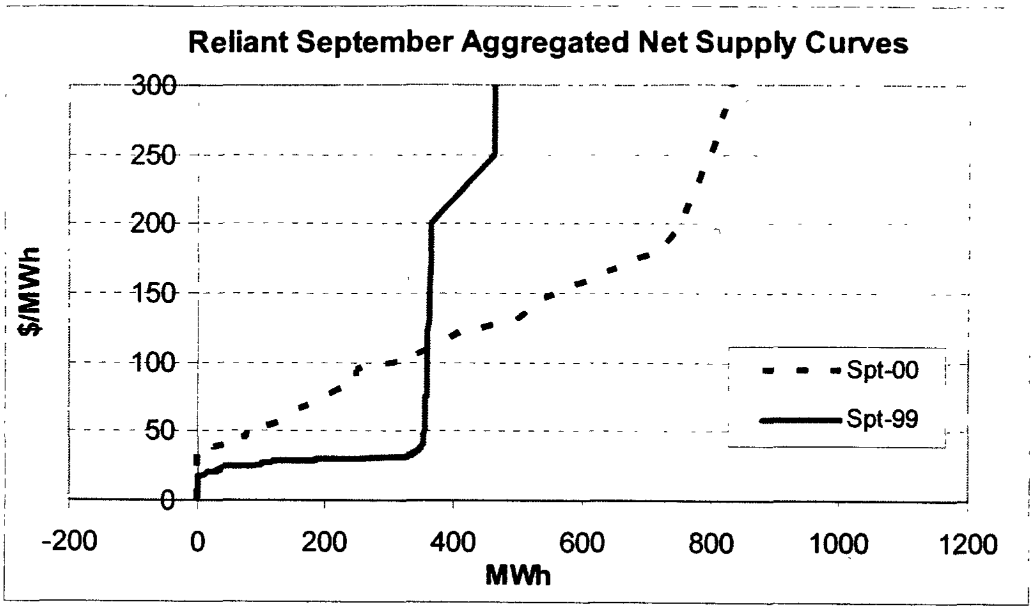

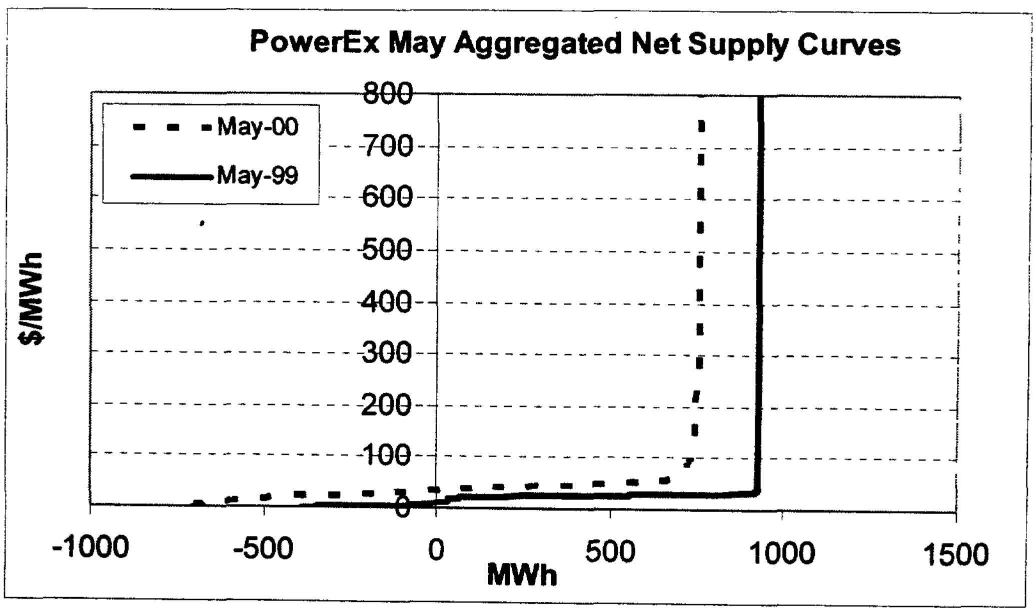

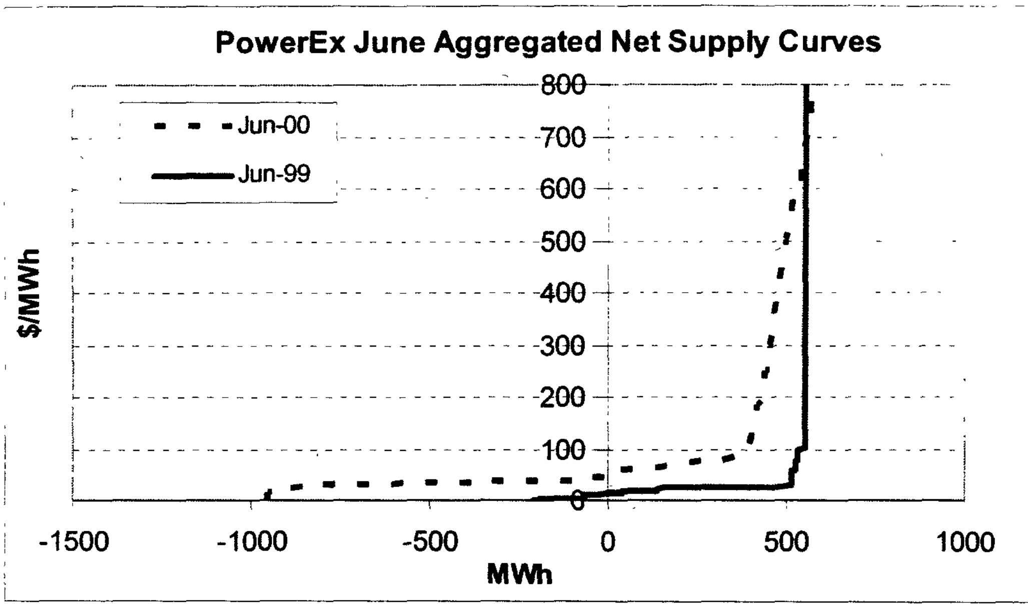
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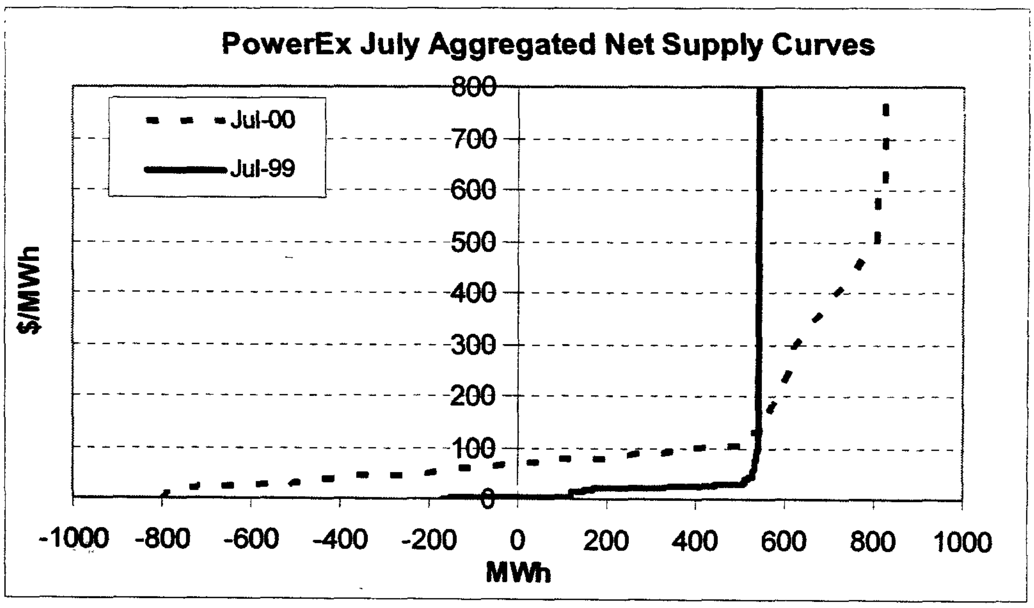
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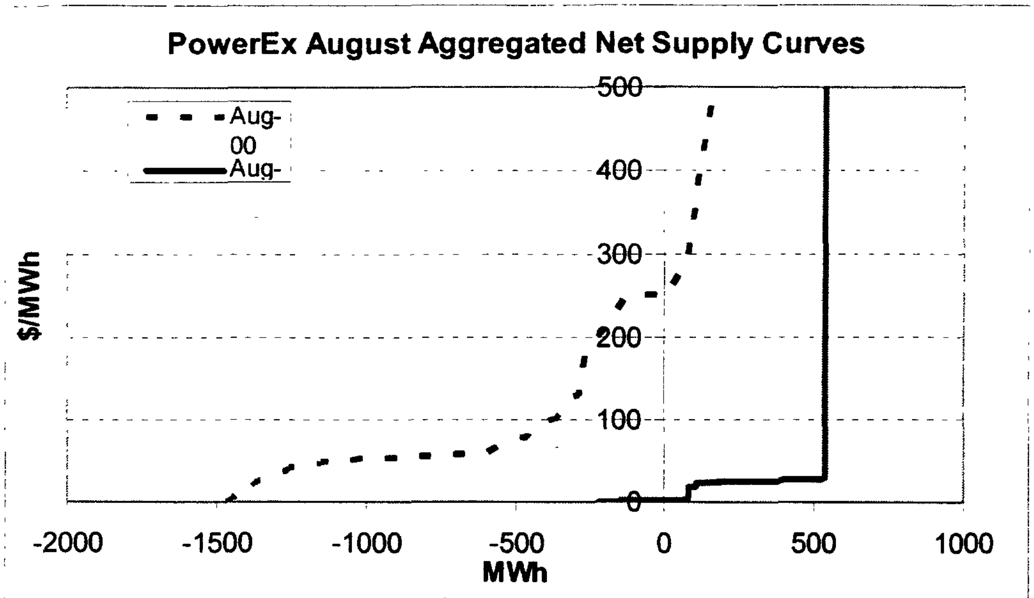
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Aug-
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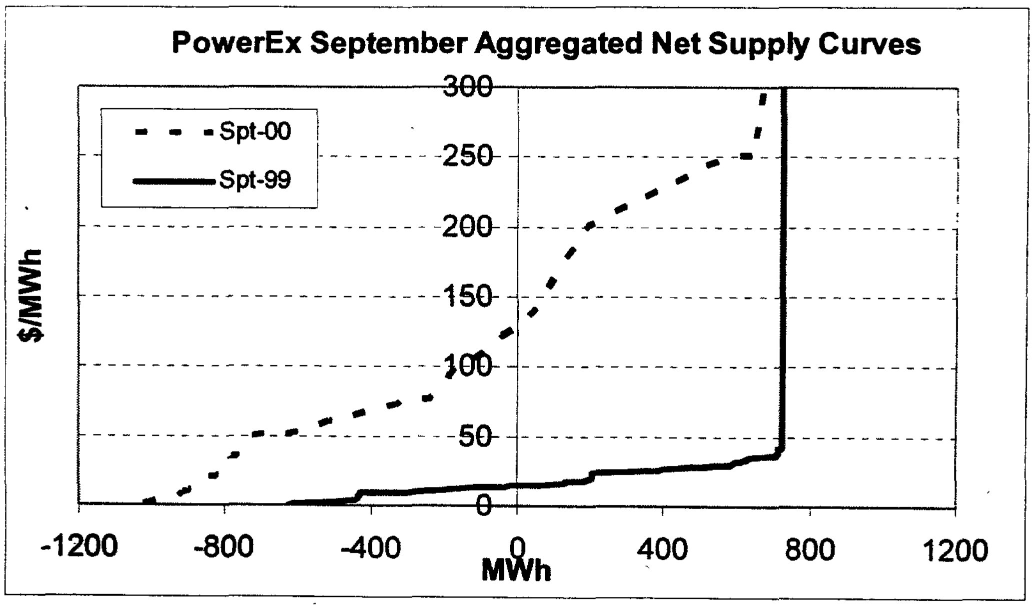
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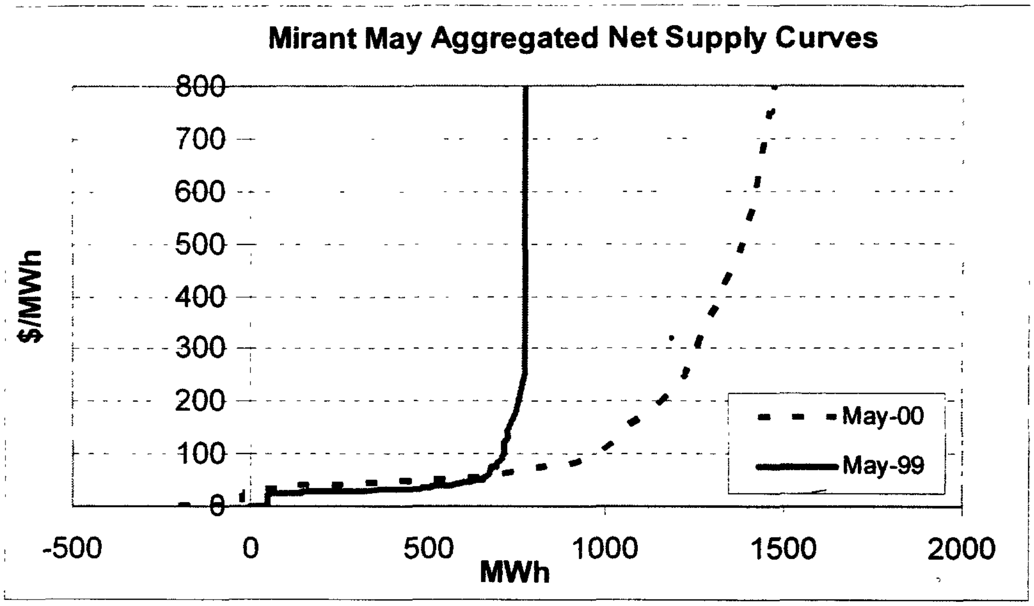
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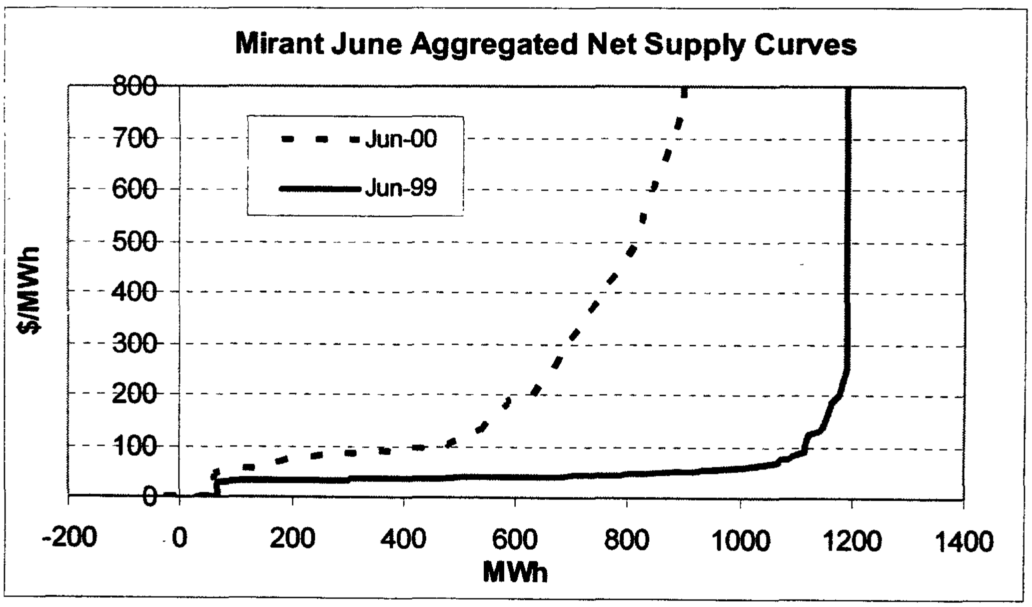
May-00
May-99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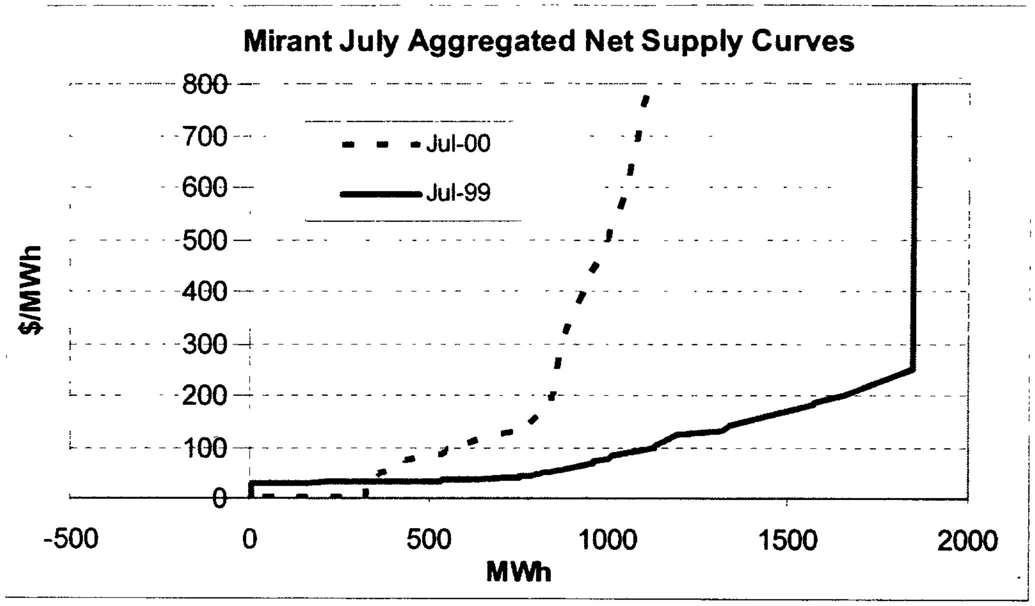
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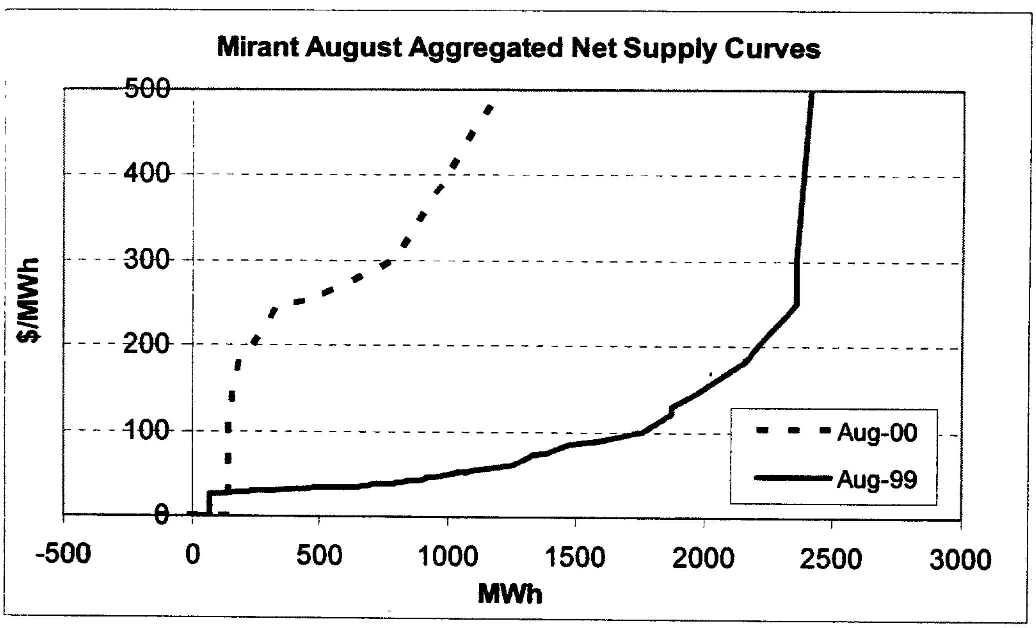
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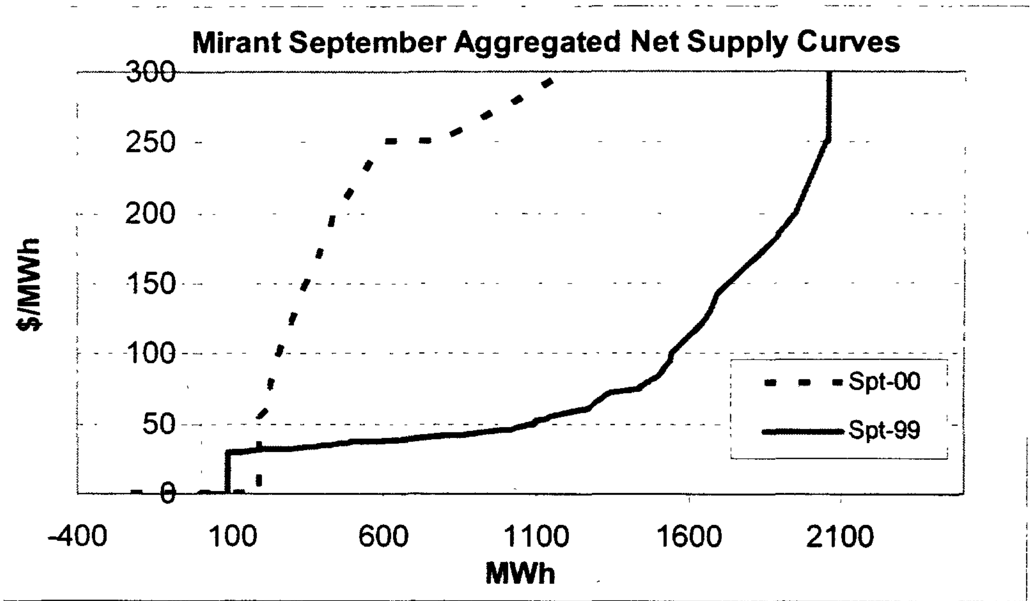
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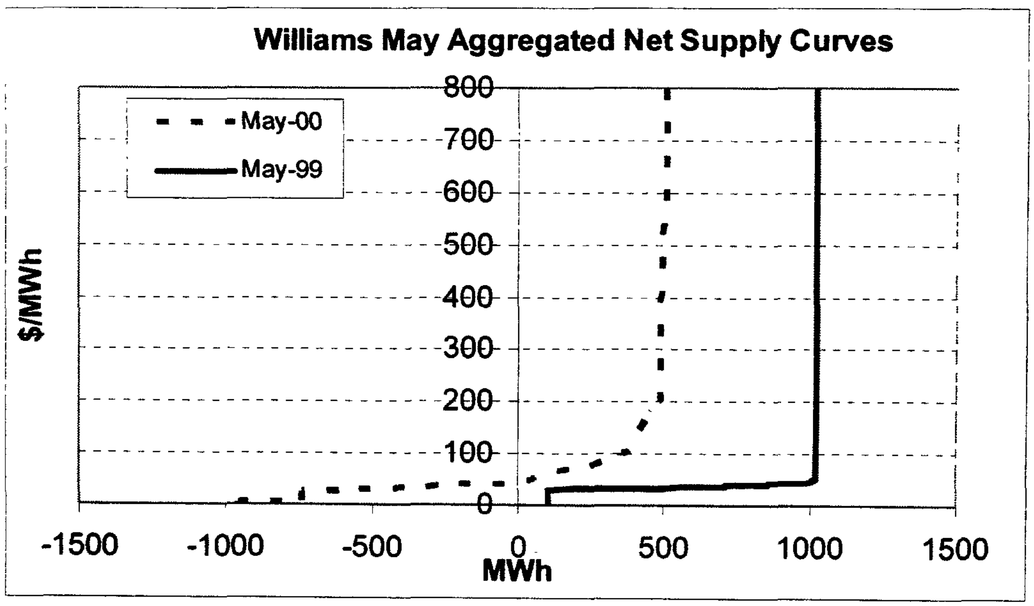
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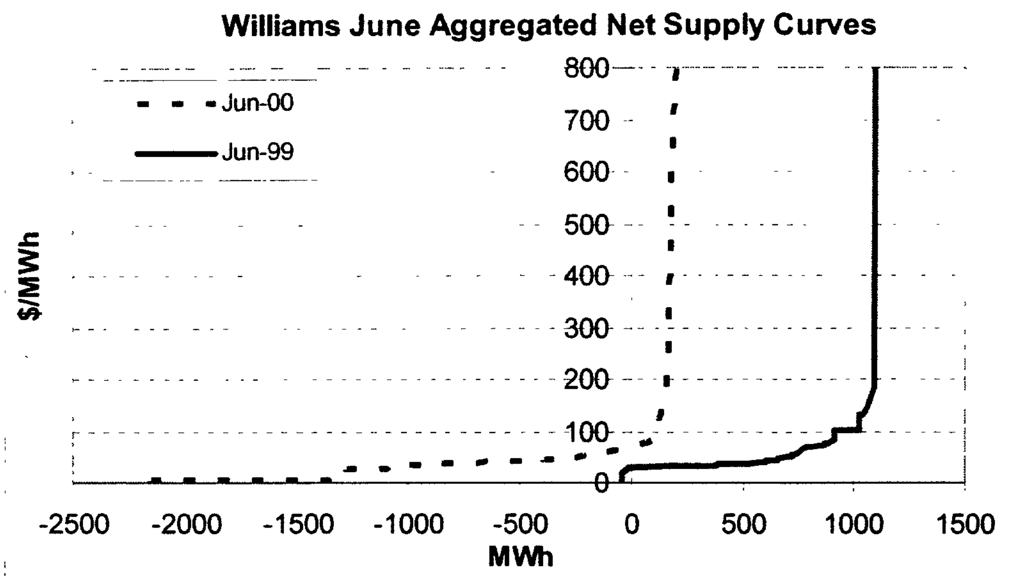
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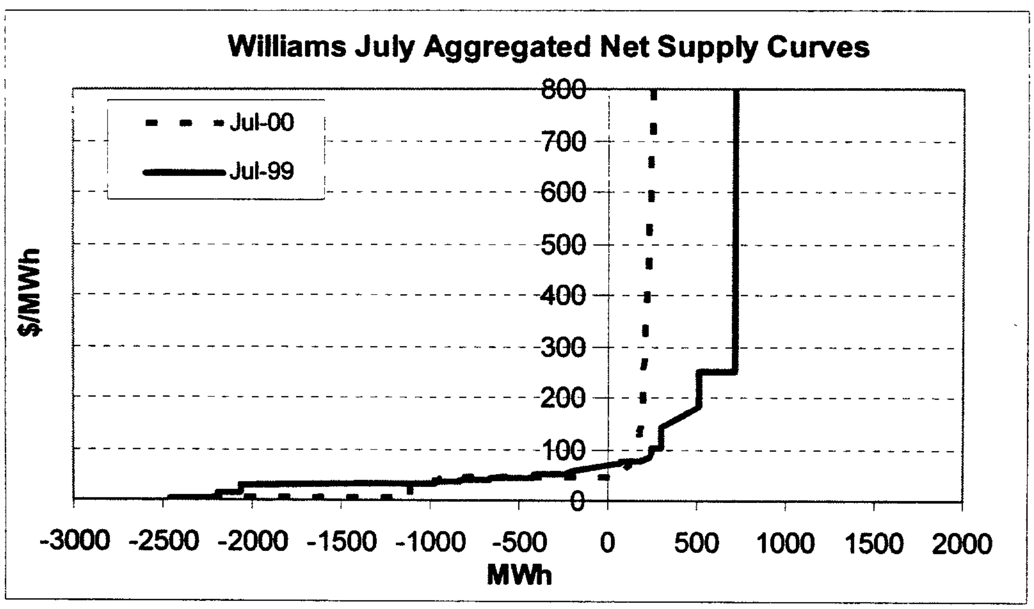
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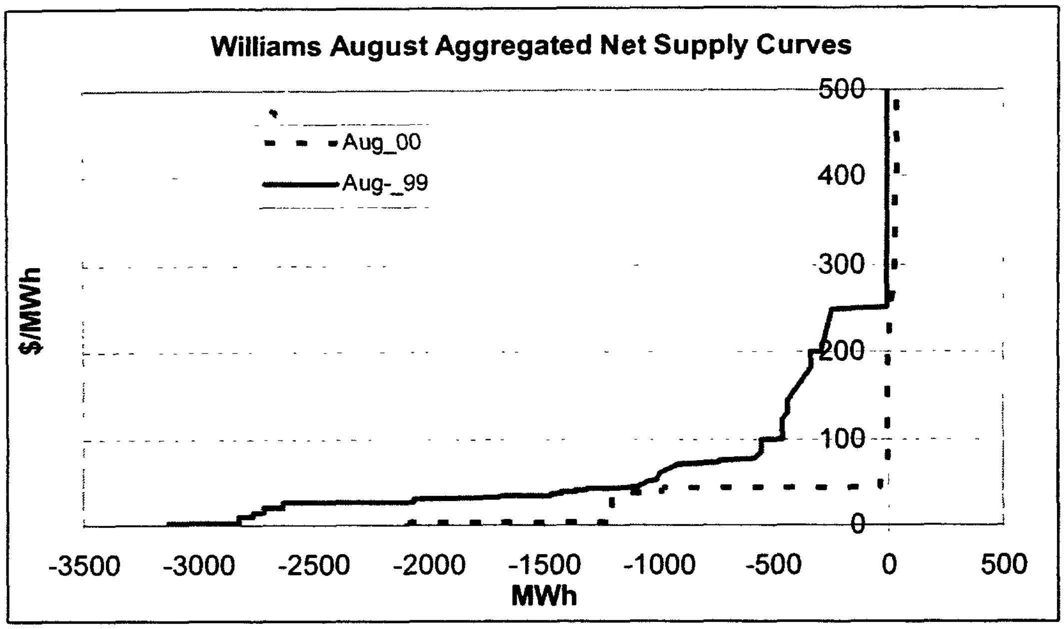
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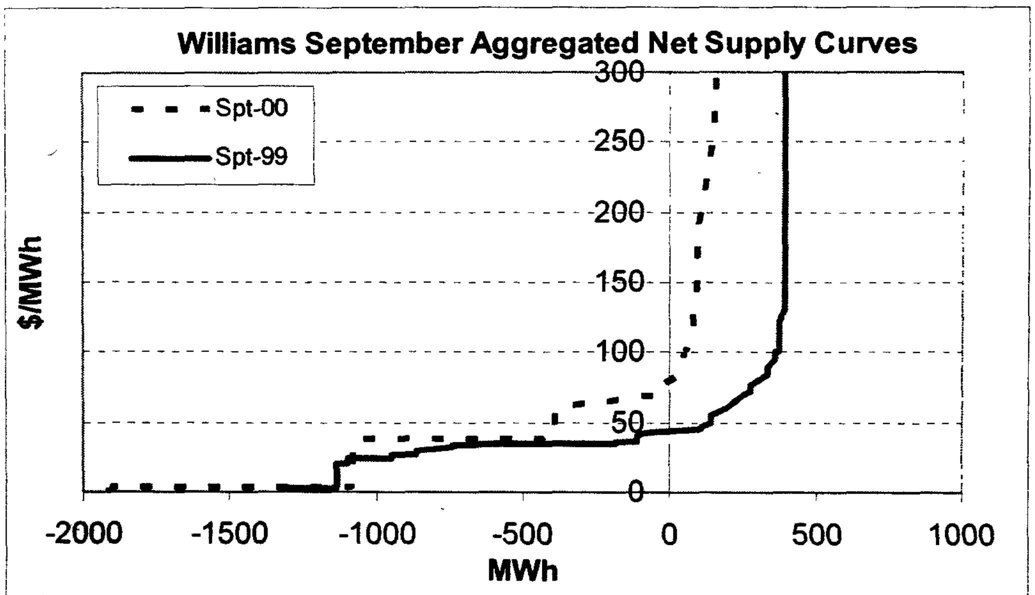
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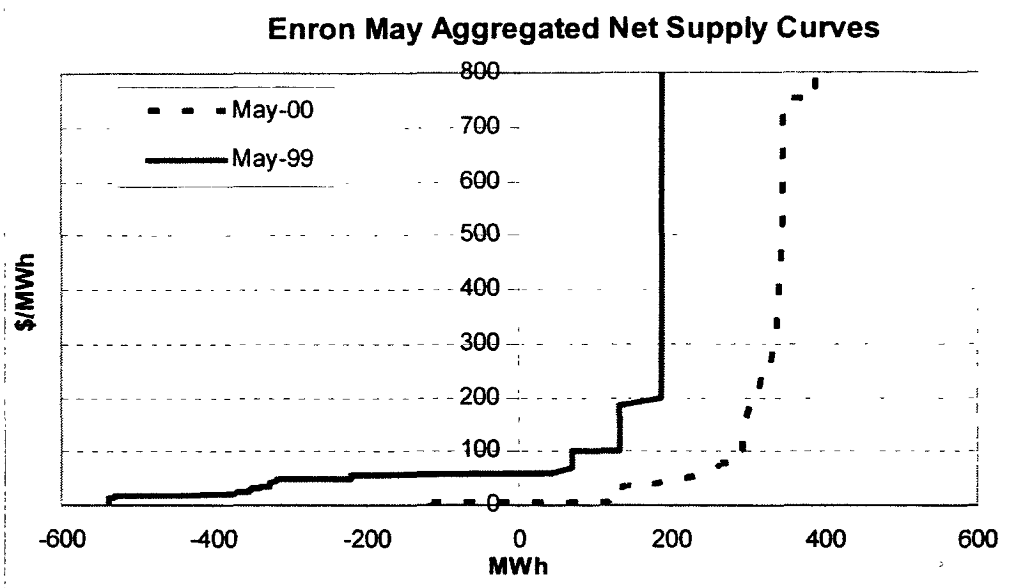
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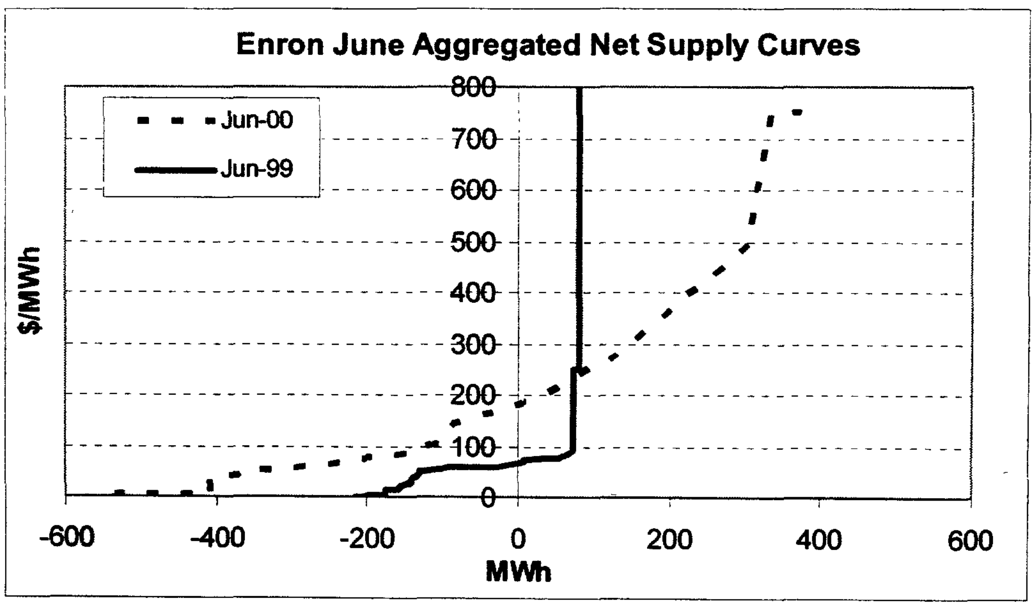
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Jun-99
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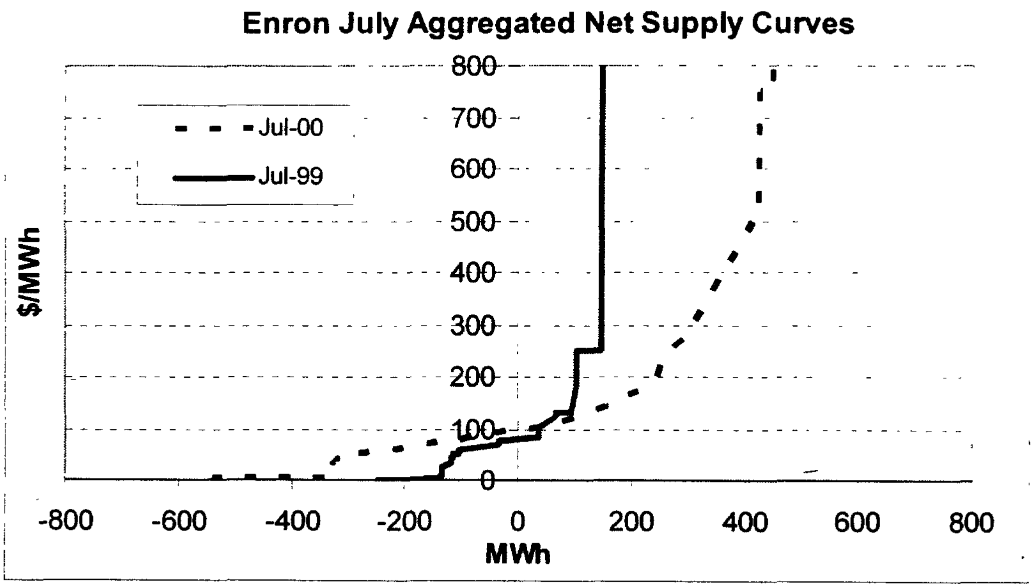
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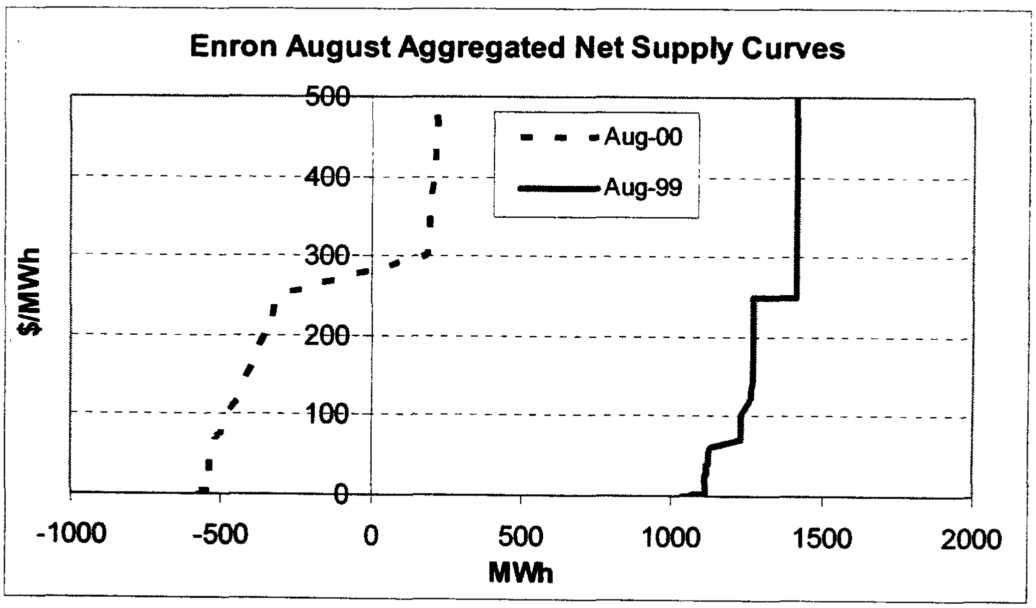
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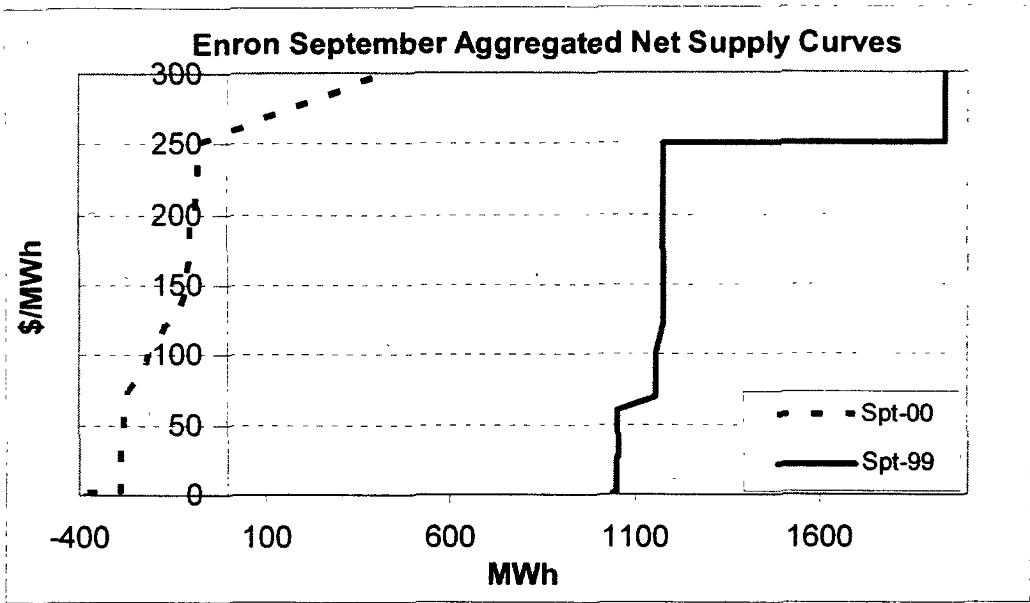
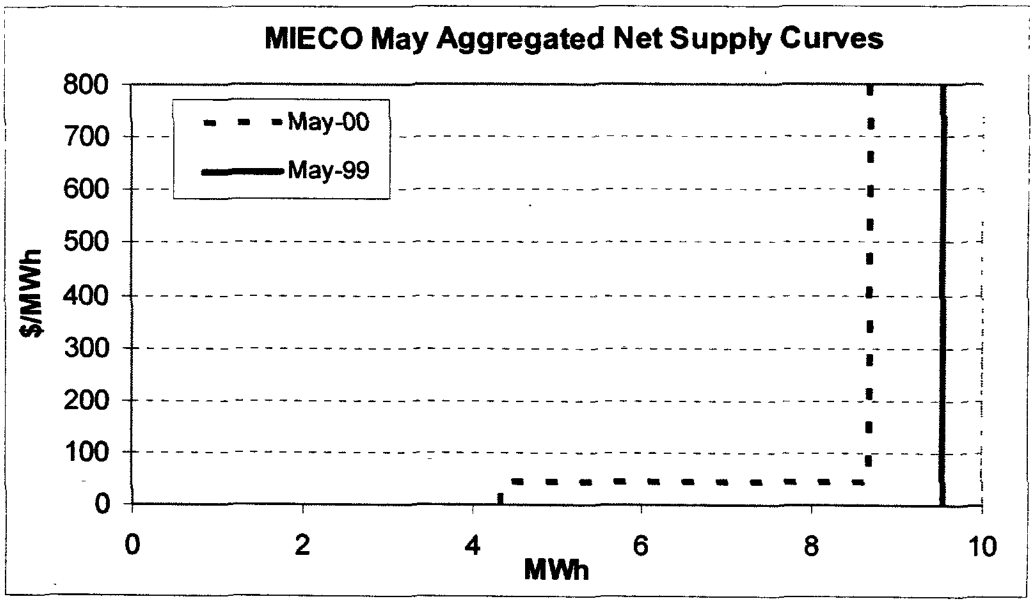
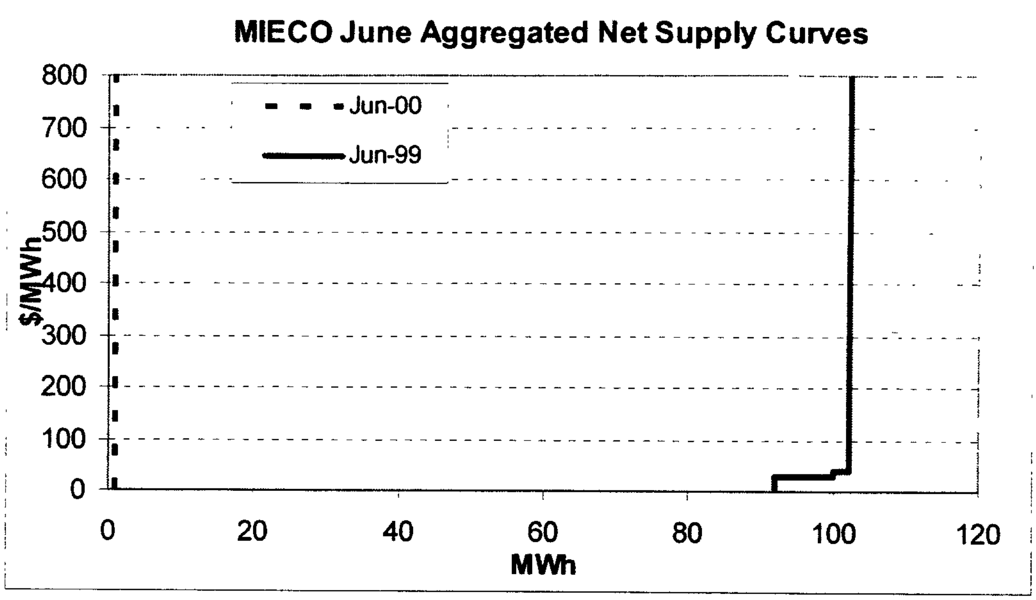
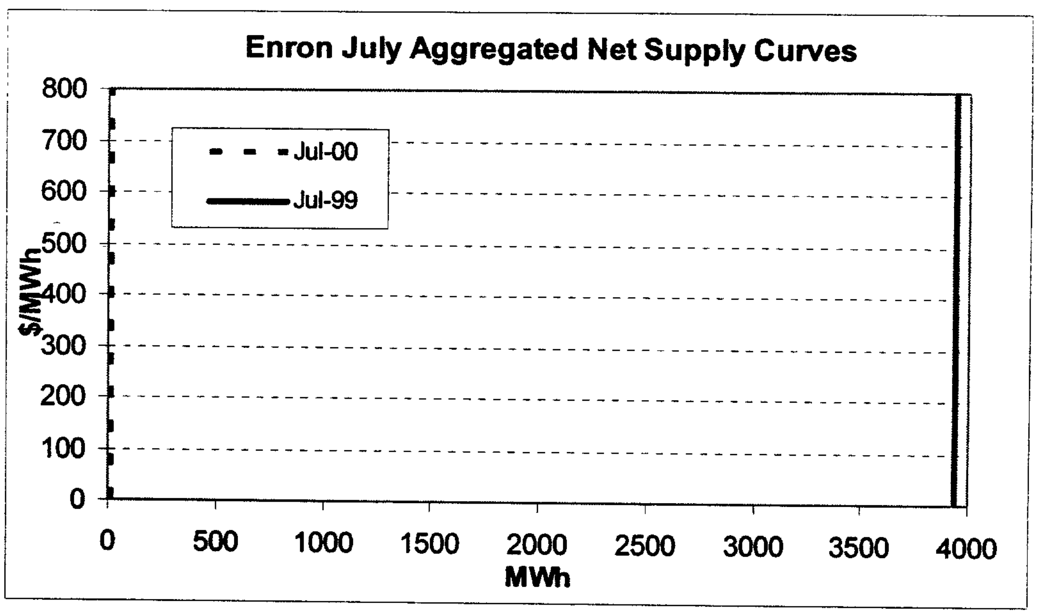
2000
MWh

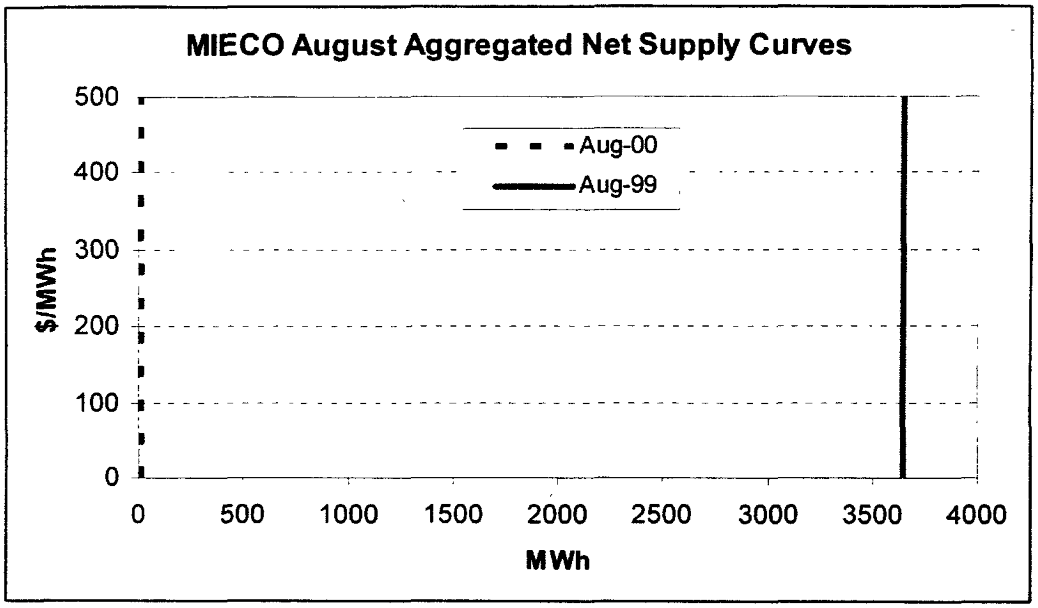

Enron September Aggregated Net Supply Curves
300
250
200
150
100
50
0
$/MWh
-400
100
600
1100
1600
MWh
Spt-00
Spt-99

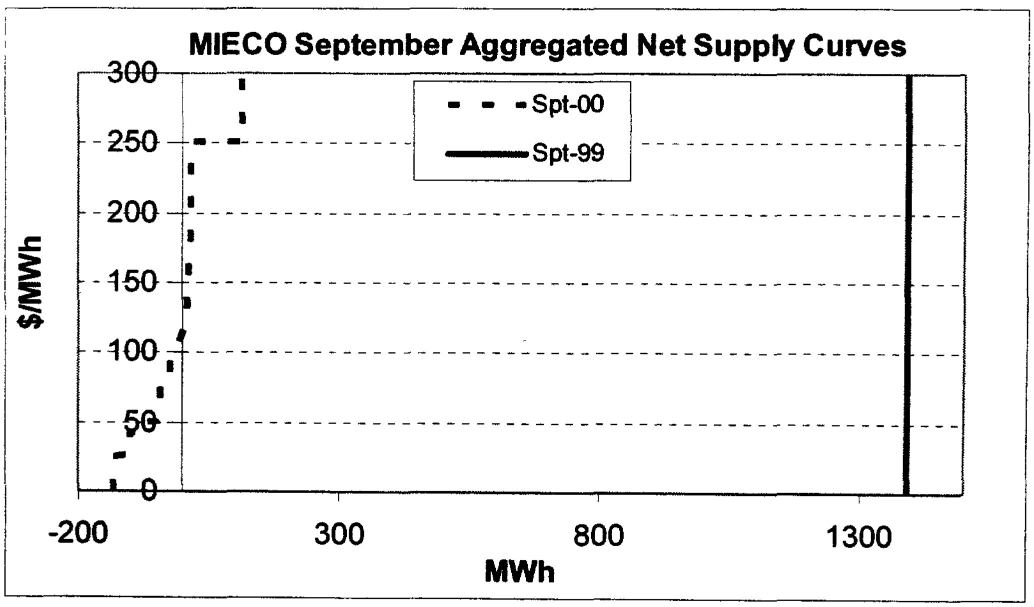

MIECO May Aggregated Net Supply Curves
800
700
600
500
400
300
200
100
0
$/MWh
0
2
4
6
8
10
MWh
May-00
May-99

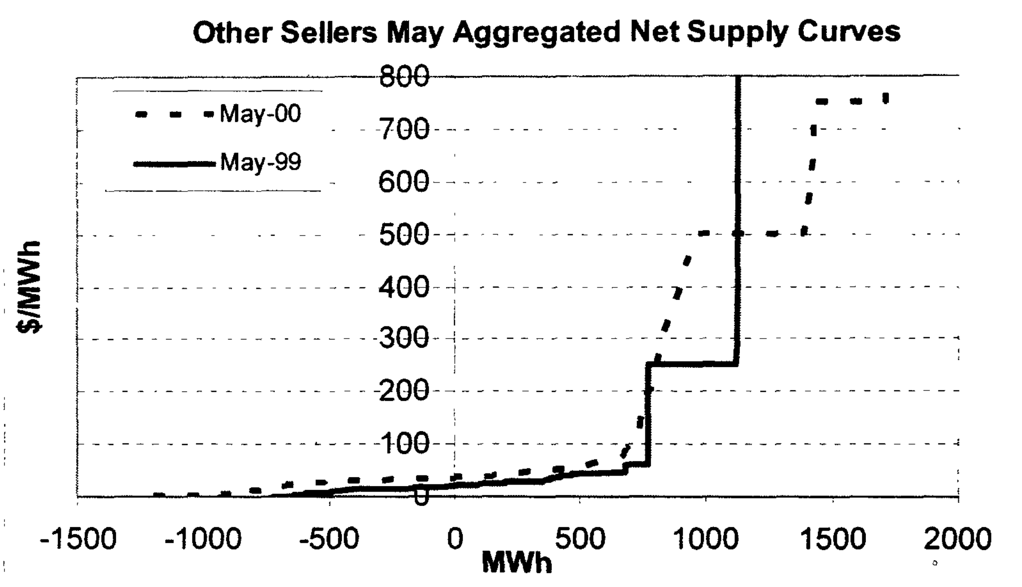

MIECO June Aggregated Net Supply Curves
Jun-00
Jun-99
$/MWh
800
700
600
500
400
300
200
100
0
0
20
40
60
80
100
120
MWh

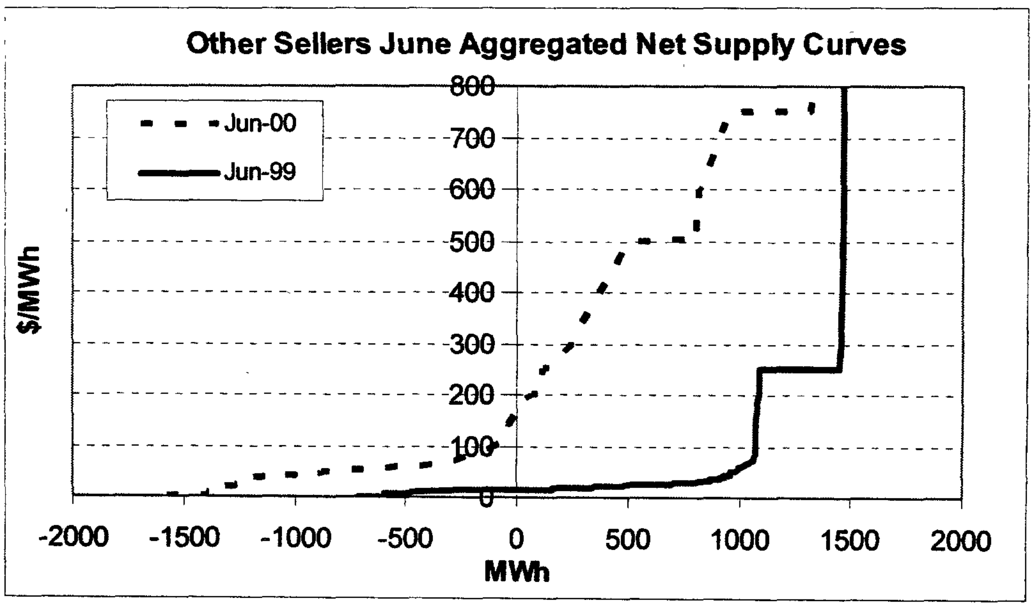

Enron July Aggregated Net Supply Curves
Jul-00
Jul-99
$/MWh
800
700
600
500
400
300
200
100
0
0
500
1000
1500
2000
2500
3000
3500
4000
MWh

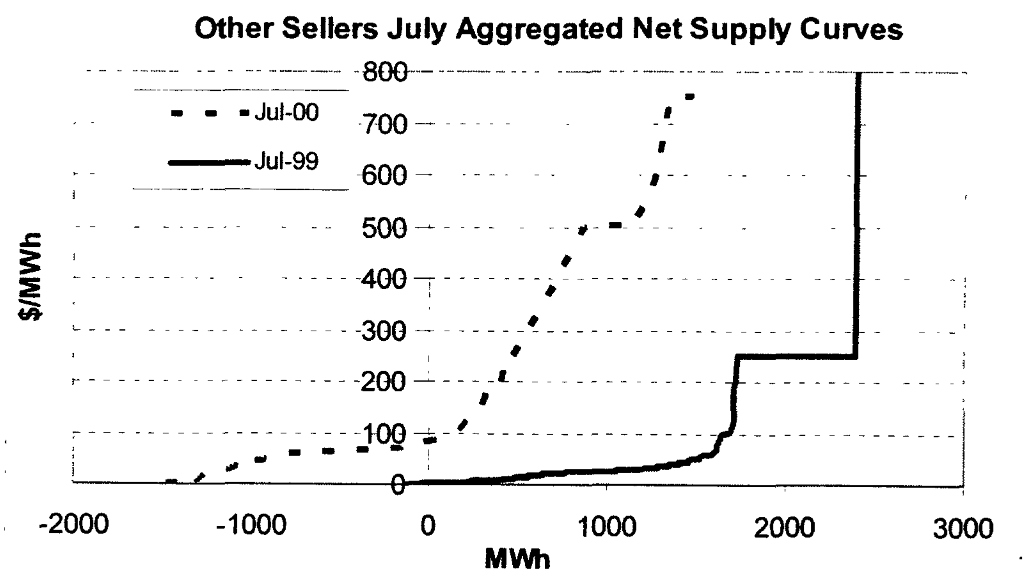
CONTAINS PROTECTED MATERIAL –
NOT AVAILABLE TO COMPETITIVE DUTY PERSONNEL

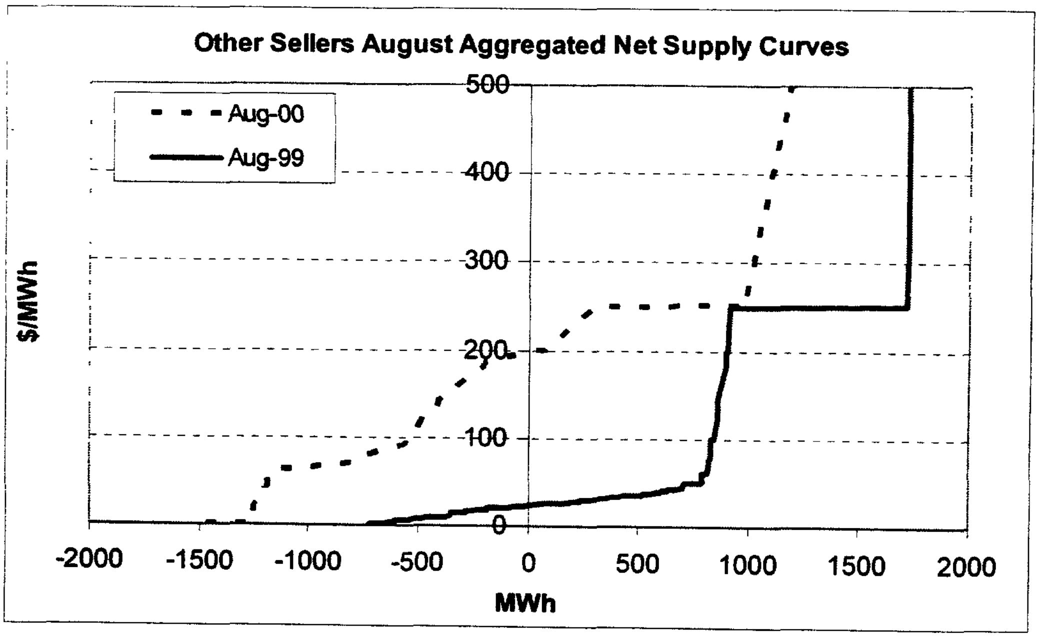


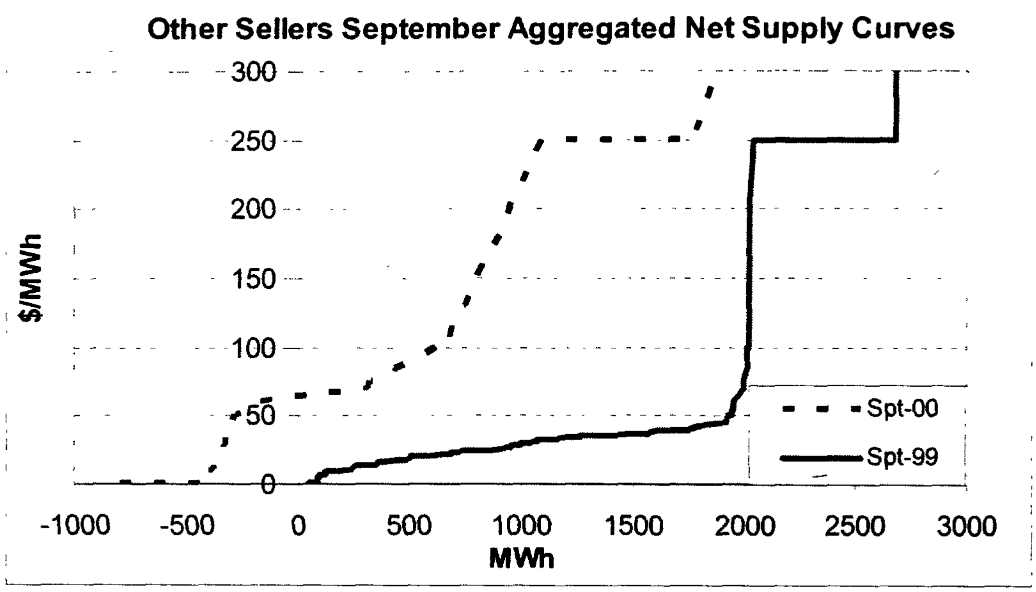



Other Sellers May Aggregated Net Supply Curves
May-00
May-99
$/MWh
MWh
800
700
600
500
400
300
200
100
0
-1500
-1000
-500
0
500
1000
1500
2000


Other Sellers June Aggregated Net Supply Curves
Jun-00
Jun-99
$/MWh
MWh
800
700
600
500
400
300
200
100
0
-2000
-1500
-1000
-500
0
500
1000
1500
2000


Other Sellers July Aggregated Net Supply Curves
Jul-00
Jul-99
$/MWh
800
700
600
500
400
300
200
100
0
-2000
-1000
0
1000
2000
3000
MWh


Other Sellers August Aggregated Net Supply Curves
Aug-00
Aug-99
$/MWh
500
400
300
200
100
0
-2000
-1500
-1000
-500
0
500
1000
1500
2000
MWh



Maximum Quantity Bid Into the California Power Exchange for Hour 16 as a Proportion of Total Load April 1, 1998 to November 30, 2000