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Exhibit No. CA-9

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
PHILIP HANSER
ON BEHALF OF THE CALIFORNIA PARTIES

Index of Relevant Material Template

Submitter (Party Name)	California Parties
Index Exh. No.	CA-9
Privileged Info (Yes/No)	Yes
Document Title	Prepared Testimony of Philip Hanser
Document Author	Philip Hanser
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	Units were falsely reported to the ISO that generating units were forced out of service for mechanical reasons when the plant's own records show that the plant was capable of normal operation. Units were placed on "reserve shutdo wn" when no maintenance was required, during times when the ISO had declared a system emergency. Units were withheld by not bidding the output into the market even though the plant was fully operational. This withholding behavior occurred during numerous system emergencies. Generators withheld generation from the market by bidding high, and in excess of its costs, so as to deliberately price itself out of the market.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95 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	In at least fourteen incidents spanning about thirty days, a number of entities reported to the ISO that generating units were unavailable due to required maintenance or repairs or other limitations when their own internal records show that the units were, in fact, available. Eight of these incidents occurred during CAISO-declared system emergencies. There were at least twenty two instances in these same Sellers' records tht show they placed their units on Reserve Shutdown during CAISO declared emergency periods even though they were operable. Such forms of physical withholding would not only raise prices, but it also made it more difficult for the CAISO to maintain system reliability.

Party/Parties performing any alleged manipulation	Dynegy, Reliant, Mirant, Duke and AES/Williams

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

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**PREPARED TESTIMONY OF
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I. INTRODUCTION

Q. What is your name and with whom are you associated?

A. My name is Philip Hanser. I am a Principal at *The Brattle Group*, an economic and management consulting firm with offices in Cambridge, Massachusetts; Washington, DC; and London, England. My business address is 44 Brattle Street, Cambridge, MA. I have been employed at *The Brattle Group* since 1996.

Q. What are your qualifications?

A. Prior to my affiliation with *The Brattle Group,* I was a Principal at Putnam, Hayes and Bartlett and a program manager at the Electric Power Research Institute. I have also held academic positions at Columbia University, University of California, Davis, and University of the Pacific, Stockton, California. I have guest lectured at Massachusetts Institute of Technology and Stanford University. I served for six years on the American Statistical Association's advisory committee to the Department of Energy's Energy Information Administration. I have published in various journals and serve as a reviewer for *The Energy Journal* and the Institute of Electrical and Electronics Engineers' *Transactions on Power Systems*.

I have previously testified before the Federal Energy Regulatory Commission (the "Commission" or "FERC") and various state public service commissions on matters involving utility mergers, horizontal and vertical market power analyses, gas pipeline rate issues, the cost of capital and transmission tariffs, as well as others. I have provided testimony and competitive analyses before the Commission on behalf of Sierra Pacific Power Company[1], Boston Edison Company[2], Edison Mission Energy[3] and other companies. A more complete description of my qualifications appears in Appendix PQH-A.

Q. On whose behalf are you submitting this testimony?

A. I was retained by Southern California Edison Company ("SCE").

Q. What is the purpose of your testimony in this proceeding?

A. My testimony consists of two parts. In this first part, I am responding to the request by SCE to investigate whether there were false generation plant outages reported by any of the major owners of gas-fired generating plants in California to the California Independent System Operator ("CAISO") in the California market between January 1, 2000 and June 20, 2001.

[1] Docket No. EC01-66-001.
[2] Docket No. ER01-890-000.

In the second part of my testimony I assess the bidding behavior of major generation sellers in California to see if there is evidence of the exercise of market power. Specifically I sought to determine if these sellers altered their bids in ways that were not related to costs but were instead in response to changes in supply/demand conditions and changes in a particular seller's position in the market, that is, the seller's ability to profit from price increases. The FERC has itself recognized this type of behavior as indicative of market power, a position that is well-supported in economic theory. Specifically, the FERC found in its April 26, 2001 Order in this proceeding that bids that vary with system conditions and not changes in underlying cost are anti-competitive.

Q. Which sellers did you examine?

A. The sellers I examined were AES/Williams Energy Services Company, Duke Energy, Dynegy, Mirant (sometimes operating under the name Southern Company Energy Services), and Reliant. I refer to these individually as AES/Williams, Duke, Dynegy, Mirant, and Reliant, and collectively I will call them simply the "Sellers". All of these parties sold power into California's real-time electricity market.

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[3] Docket No. ER99-852, *et al.*

The current presence in the California market of these Sellers arises from their acquisition of generation assets divested from the Southern California Edison Company, the Pacific Gas and Electric Company ("PG&E") and the San Diego Gas And Electric Company ("SDG&E"), the investor-owned utilities in California, as a result of California's electricity market restructuring. The generation they acquired represents the majority of fossil-fired generation that can be freely bid into the California electricity markets.

Q. What are your conclusions?

A. In the first part of my testimony, I conclude that in at least fourteen incidents spanning about thirty days, Dynegy, Reliant, Mirant, Duke and AES/Williams reported to the ISO that generating units were unavailable due to required maintenance or repairs or other limitations when their own internal records show that the units were, in fact, available. Eight of these incidents occurred during CAISO-declared system emergencies. I further conclude that twenty-two instances in these same Sellers' records that show they placed their units on Reserve Shutdown (shutdown for economic reasons) during CAISO-declared emergency periods and thus kept them out of the market even though they were operable. This form of physical withholding would not only have tended to raise prices, but it also made it more difficult for the CAISO to maintain system reliability.

In reaching these conclusions, I relied solely on the generators' own records, produced in discovery, to verify the accuracy of their outage reports to the ISO. The generators have asserted that many records as to critical periods are missing. With more complete records, additional inconsistencies between plant records and outage reports to the ISO may have been identified. I have also assumed for purposes of this analysis that the records the Sellers provided are true. No attempt has been made to determine whether any of the outages recorded in the plant logs may have been unnecessary, as was the case regarding AES/Williams in May 2000 that was the subject of a Commission settlement[4]. In addition, this analysis is limited only to instances in which generators appear to have physically withheld capacity by shutting down the unit. As Dr. Reynolds explains, generators also physically withheld by not offering for sale the output of generating units that were operating and available. The limited subset of physical withholding that I examine in this part of my testimony is particularly troublesome because, by actually taking a unit off line, the generators make their units unavailable on a short-term basis even if the ISO were to issue an emergency dispatch order.

[4] Exh. No. CA-267

In the second part of my testimony, I reach three conclusions. First, it is clear that the real-time electricity market was not workably competitive as evidenced by all of the Sellers willingness and ability to submit bids that were unrelated to the underlying costs of the electric power they were selling. Second, the Sellers with the most to gain from higher prices as a result of the market position were consistently the most aggressive in bidding above their marginal costs. Third, Sellers' exploited the opportunities provided during periods of tight market conditions to raise their bid prices above their marginal costs. Thus, not only was the market not workably competitive, but Sellers took advantage of their market power.

II. PART I – THE PHYSICAL WITHHOLDING OF GENERATION THROUGH THE FALSE REPORTING OF OUTAGES TO THE CAISO

A. BACKGROUND AND METHODOLOGY

Q. Please explain the importance of false declaration of plant outages.

A. False declaration of outages is one form of physical withholding of generation capacity. The false declaration of forced (or scheduled) plant outages to the ISO is one of the more problematic forms of physical withholding, because of the severe reliability implications (particularly during emergency conditions) and its implicit signaling function aimed at affecting the behavior of other market participants.

It is important to understand how fundamental the availability of generation is to a well-operating electricity market and how large the impact of false outage reporting can be. As has no doubt been pointed out to this Commission before, electricity is a unique commodity. Its market must remain in continuous balance between supply and demand at all times. Even brief moments of imbalance can have the direst consequences for all participating in the market, but particularly for consumers. This requirement for continuous supply/demand balance, in combination with electricity's lack of storage capability, translates into a requirement for the continuous operation of power plants sufficient to meet demand because there are no substitutes or alternatives to their running. This potentially leaves the entity responsible for ensuring the operation of, and reliable delivery of power from, the market at the mercy of power plant operators if the markets are not workably competitive. If the plant operators should choose to falsify the information they provide on their plant's availability, then it will reduce the capability of the system operator to meet the uncertain demands of the market place. This will place the market into an increasingly easy position to be manipulated by any that realize the precarious position that the system operator is in.[5] Thus, of the various schemes to manipulate the market that have been revealed to the Commission over the past two years, most have as their foundational requirement that the market is short of resources. In this setting, the system operator may turn to whatever party can provide relief from that position, even if that may be at great cost to the market's consumers.

Q. Is there any indication of physical withholding in the California electricity market in the 2000-2001 period?

A. There is much evidence to suggest Sellers in California engaged in strategic withholding of generation under a variety of subterfuges as a means of driving up the market-clearing price for electricity. For example, the March 2001 report of Anjali Sheffrin concluded that physical withholding took place 30% of the hours on average for the Sellers during May – November 2000 period.[6] Moreover, the CPUC's September 2002 report and its January 2003 update alleged that physical withholding of generation took place during state-wide black-outs or interruption days through several methods, including generators'

[5] A similar point was made by James Detmers, who noted that some Sellers forced the CAISO real time operations personnel to negotiate the financial terms when the CAISO called the Sellers to provide generation during system emergencies. See "Appendix C-Declaration of James Detmers" in support of CAISO's Amendment 33 Filing (Docket No. ER01-607).

[6] Anjali Sheffrin, "Empirical Evidence of Strategic Bidding in California ISO Real-Time Market," March 21, 2001, Exh. No. CA-244.

failing to take necessary actions to bring plants on-line after outages.[7] It was also argued in the same CPUC report that some generators violated Emergency Orders issued by the Secretary of Energy in December 2000 and January 2001 requiring certain sellers to make generation available for sale to the ISO ("DOE Orders") by not bidding all available generation capacity into ISO markets.

Q. Is there any indication in earlier studies or reports of false declaration of plant outages by generators?

A. There is other evidence to suggest false outage reporting. For example, there are indications that some plant operators were given instructions to delay starting up units after an outage.[8] Moreover, a recent FERC order on January 31, 2003 revealed that Reliant performed maintenance activities on June 20-21, 2000 in order to withhold bids and raise market prices.[9] The CPUC's September 2002 report also included allegations that some unidentified generators refused CAISO's dispatch orders claiming forced outages at their plants, although the plants were available.[10] Similarly, the report provides an instance in which an unidentified generator declared some of its units off-line after CAISO operators declined to negotiate the financial terms of units

[7] "CPUC Staff's Wholesale Generator Investigation Report" September 30, 2002, Chapter 3, pp. 21 – 50. (Exh. No. CA-246). "Supplement to the CPUC Staff's Wholesale Generator Investigation Report Dated September 30, 2002," January 30, 2003. Exh. No. CA-247).
[8] FERC, "Non-public Appendix to Order Directing Williams Energy Marketing & Trading Company and AES Southland, Inc. to Show Cause", Docket No. IN01-3-000. (Exh. No. CA-147)

providing power.[11] Moreover, the FERC's November 2000 report found that there was a high correlation between the PX prices and the total amount of generation capacity subject to outages happening one day before price increases during the period May to August, 2000.[12] Although the latter finding does not by itself permit a conclusion of declaring false outages as a mechanism to raise prices[13], it is strongly suspicious, and minimally requires further examination of plant outages.

Q. Have you discovered any additional information indicating false reporting?

A. In addition to the specific incidents described below, the documents of the generators reveal that their reporting was inaccurate or misleading. Williams planned for "forced" outages when ISO requirements would not allow scheduled outages.[14] Duke simply failed to report short outages when it was economically advantageous.[15] Mr. Matthew D'Agastino, one of Duke's head traders, alerted his entire staff: "Please talk with me or Todd [Hendricks] about how we need to handle unit outages and what we report to the ISO."[16] Outages were taken with completely spurious justifications, as when Dynegy

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[9] FERC, "Order Approving Stipulation and Consent Agreement", Docket No. PA2-2-001.
[10] CPUC September 2002 report, p. 52.
[11] CPUC September 2002 report, p. 53.
[12] FERC Staff November 2000 Report, Chapter 2, pp. 19 and 21 and Chapter 5, p. 23. (Exh. No. CA-245)
[13] A high correlation between market prices and outages can also be explained by real outages driving up market prices due to reduced market supply.
[14] AES-A016562A, Eric Pendergraft to Mark Woodruff, re:NAD With Shutdown, dated 2/6/01. (Exh. No. CA-152)
[15] Exhibit 6 to the Deposition of Todd Hendricks, Todd Hendricks to Austin Faruzzi and others, re: More info on unit outages, dated 8/17/00 (Exhibit No. CA-340).
[16] Exhibit 7 to the Deposition of Todd Hendricks, D'Agastino to Austin Faruzzi and others, re: Unit Outages, dated 8/1700 (Exhibit No. CA-340).

took out one of its units in August of 2000 on the basis of a report written in 1986 despite its having been overhauled several times since then.[17] It should also be recognized that the generators were quite aware of the impact of outages upon market prices. In an AES Control Operator Log, along with other entries regarding performance issues with the there units appears an observation by the unit operator: "Note: Price on PX went up after we came down."[18]

Q. Does false outage reporting always take the form of submitting false information to the CAISO?

A. No. The most blatant forms of false reporting are essentially "sins of commission," i.e., the seller provides information to the CAISO that is not correct. However, there are more subtle variants of false reporting that are more like "sins of omission." For example, in one incident a seller was asked by the CAISO if a unit that was out on repairs could be brought on more quickly than originally scheduled, likely because of its potential need. The seller replied to the CAISO that they were working to the max to finish the required repairs. However, employees in internal telephone conversations indicated that the repairs could have been expedited, but saw no need to do so. It appears they were so motivated because they wanted to wait until such time

[17] DYN AG 0144936. (Exh. No. CA-184)
[18] CALAESDUNN 004928, Undated AES Control Operator Log. (Exh. No. CA-154)

as they could be paid their bid which, given the date of their conversation, was imminent with the advent of the soft bid cap[19].

At another seller one employee related to another in an e-mail that the CAISO knew that one of its units was suffering from a waterwall leak. However, the seller failed to tell the CAISO that it was likely that they would bring the unit down two days hence. Furthermore, the e-mail essentially directs the employees it is written to not say anything to the CAISO about the possibility of scheduling an outage[20].

Q. Please provide an overview of the amount of outages that occurred during January 2000 – June 2001 time period.

A. I have used data on unit availabilities from the CAISO's SLIC logs to compare total outages to total capacity owned by each Seller during this time period. As shown in Appendix PQH-B, Exh. No. CA-10 pages 8-9, total outages of all the units owned by the Sellers was about 4,000 MW out of about 18,000 MW total capacity in the first half of year 2000. But the outages started increasing within the second half of the year, and reached about 8,000 MW (about 43% of total capacity) by the beginning of December 2000. The total outages dropped dramatically on December 8 (the date when the $250/MWh "hard cap" became

[19] M INI12 (Exh. No. CA-283)
[20] MIR00001421552 (Exh. No. CA-180).

"soft"), and went down to about 4,000 MW by the end of year 2000. The outages in the first half of 2001 were on average about 2,000 MW higher than the outages in the first half of 2000. The unusually high forced outage rates for the Sellers after the first half of year 2000 can also be observed in Appendix PQH-F. Appendix PQH-F, Exh. No. CA-10, pages 39-93 provides a comparison of the forced outages observed in the units owned by the Sellers to national averages.

Q. How is the rest of your testimony organized?

A. Section B describes the general approach of my analysis. Section C describes my findings in general terms and then provides summary information for each of the tables we developed.

Q. Have you prepared an analysis that compares the level of outages declared by the Sellers to the national averages among plants of similar age and characteristics?

A. Yes. I prepared a benchmark analysis, presented in Appendix PQH-F, Exh. No. CA-10, pages 39 - 93 that examines the outage rates of the California plants relative to the performance of similar plants nationally.

B. ANALYTICAL APPROACH TO ASSESSING FALSE OUTAGES

Q. What was your approach in identifying outages for which the Seller indicated to the CAISO that a generating unit was not operable, but internal records indicated otherwise?

A. My approach was to examine all information available about the Sellers' generating units. I began with the information that the Sellers provided to the CAISO on the availability of their units to provide power, and compared the information they provided to the CAISO with the Sellers' own records of the availability of their plants. I also examined and compared other information (such as the outage reason, and the notes kept by the CAISO's dispatchers and outage coordinators) provided in those databases to have a better understanding of the outages I examined. Finally, I reviewed the logs kept by plant operators or shift supervisors for selected outage events to explain the differences between the records kept by the CAISO and the Sellers' own outage records. I also consulted with an engineer experienced in generating plant operations to assist in assessing the information provided by the Sellers, particularly the plant control operator logs.

Q. Please further elucidate the CAISO's SLIC outage databases.

A. The information provided by the Sellers to the CAISO took two forms. First, the seller would notify the CAISO (by phone, email, or fax) of outages to provide information about the size, reason, expected start and end times, and then later the actual start and end times of the outage. This information is kept by the CAISO in the "Outage Table" sub-database within the Scheduling and Logging of ISO of California ("SLIC") database. Second, the seller would notify the CAISO of changes in the plant's operating status and availability within the outage event initially communicated to the CAISO. This information is kept in the generation availability table ("Availability Table") sub-database within the SLIC database. A notification of a change in a unit's availability would usually be accompanied by a note recorded by the system operator as to the cause of the change in status. For example, if a seller called the system operator to notify the CAISO that a part had failed and had caused a change in a unit's generating availability or capability, then that would be noted by the system operator. Although both the outage table and the availability table contain information that can be used to assess the availability of generating units, the CAISO indicated that the Availability Log is used by the CAISO's dispatchers to assess unit availability. Therefore, I consider the Availability Table as a reliable source for changes in unit availability over time.

Q. What information did the Sellers record about outages?

A. The outage information that the seller had took a variety of forms. First, prior to their sale, the plants owned by the California utilities would collect data on the availability of units and submit such information to the North American

Electric Reliability Council ("NERC") for retention in a national database called Generation Availability Data System ("GADS"). Some Sellers maintained similar records and submitted such to the NERC. The other Sellers maintained GADS-like records, but made no submission to the NERC. Second, the most direct source of information from Sellers are their plant operator logs and shift supervisor logs. The plant operators would maintain a running log that recorded on a real-time basis the status of the plant's units. Finally, there is information from the Sellers in the form of internal memoranda, e-mails, etc. that indicate their withholding strategies or actual behavior. Appendix PQH-G, Exh. No. CA-10, pages 94 – 102, describes the preparation of the GADS outage data provided by the Sellers, capacity data and the CAISO's SLIC availability data for my analyses.

Q. Do you have any concerns about the data provided by the Sellers?

A. Yes. The outage data is not complete for some of the Sellers. There are indications that, in fact, at least one seller did not want to keep good records on the plant's outage status in order to maximize availability payments.[21] Nonetheless, I have treated the outage data and the plant control operator logs as being correct and honestly recorded for purposes of this analysis.

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[21] Williams e-mail, WEMT CAAG046385 (Exh. No. CA-254).

Q. Did you investigate all discrepancies between the availability data in SLIC and GADS databases between January 2000 and June 2001 that appeared as suspicious?

A. No, I did not. I did not examine relatively small deratings. I investigated only the largest incidents and those for which there was relatively complete data and, thus, we are not putting before the Commission the totality of suspicious outages.

C. RESULTS

1. ***Units Reported To The CAISO As Unavailable Due To Required Maintenance Or Other Limitations, Where Sellers' Internal Records Show That The Unit Was Available***

Q. Did you find any incidents involving potentially false declaration of outage status to the CAISO during emergency periods?

A. Yes. I found fourteen incidents, spanning about thirty days, in which a Seller declared to the CAISO that a unit was unavailable due to required maintenance or other limitations, while that Seller's own records show that unit was on reserve shutdown or otherwise available for operation. These incidents include the following:

Name of Seller	Unit	Time Period	Emergency Period?
AES/Williams	Redondo 6	4/3/00 – 4/6/00	No
AES/Williams	Alamitos 7	8/15/00	Yes
Dynegy	El Segundo 1	8/30/00 – 9/3/00	No
Mirant	Pittsburg 1	10/20/00– 10/22/00	No
Reliant	Etiwanda 1	11/14/00– 11/16/00	Yes
Duke	Oakland 1	11/20/00– 11/22/00	Yes
AES/Williams	Redondo 5	12/19/00– 12/20/00	Yes
Reliant	Etiwanda 1	12/28/00– 12/30/00	No
Reliant	Etiwanda 2	12/28/00– 12/30/00	No
Reliant	Etiwanda 2	1/26/01 – 1/28/01	Yes
Mirant	Pittsburg 1	3/20/01 – 3/21/01	Yes
Reliant	Ellwood	4/9/01 – 4/10/01	Yes
Reliant	Etiwanda 1	5/12/01 – 5/14/01	No
Reliant	Etiwanda 5	5/30/01 – 5/31/01	Yes

Q. You indicate that some of these incidents occur during the CAISO-declared system emergencies. What does that mean?

A. The CAISO declares an emergency when the operating reserves are expected to fall below certain levels; i.e. when total available generation capacity is dangerously close to expected electricity demand. A Stage 1 emergency is declared when the actual or expected operating reserves fall below the operating reserve criteria determined by the, then, Western Systems Coordinating Council ("WSCC"), now the Western Electricity Coordinating

Council.[22] Stage 2 and Stage 3 emergencies are declared when the actual or expected reserves fall below 5% and 1.5%, respectively. If a Stage 2 emergency is declared, power service to interruptible customers is curtailed. In a Stage 3 emergency, involuntary curtailment to customers (rolling blackouts) is required.[23]

Q. What is a reserve shutdown by a generating unit?

A. A reserve shutdown is defined by the NERC as being "available for load but is not synchronized due to lack of demand"[24]. In other words, a unit is on reserve shutdown due to economic reasons, not due to physical causes such as an equipment failure.

Q. What is the importance of observing that a unit was on reserve shutdown when the Seller declared the same unit to be unavailable due to an outage according to the CAISO's SLIC records?

A. The importance of observing that a unit was on reserve shutdown when the same unit was declared by the seller to be on outage according to the CAISO's SLIC records is the following: First, such an event would indicate a false outage reporting, because that unit did not experience any outage. Second, if a

[22] WSCC, Southwest Regional Transmission Association, and Western Regional Transmission Association merged on April 18, 2002 to form the Western Electricity Coordinating Council. (http://www.wecc.biz/wscc_rta_merger.html)
[23] http://www.caiso.com/aboutus/glossary/index.html
[24] See NERC, "GADS Data Reporting Instructions", page III-12.
ftp://www.nerc.com/pub/sys/all_updl/gads/dri/sec3.pdf

unit is declared to the CAISO as being on outage, then the CAISO cannot dispatch this unit to meet electricity demand. However, if a unit is on reserve shutdown, the CAISO can call the unit to generate power when it is needed.[25] Therefore, a Seller can effectively withhold generating capacity to raise prices by declaring an outage to the CAISO, instead of reporting a reserve shutdown.

Q. What are your findings regarding AES/Williams' outage of Redondo Beach Unit 6 from April 3, 2000 through April 6, 2000?

A. As shown in Appendix PQH-C, Exh. No. CA-10 page 20, Williams reported to the CAISO that its Redondo Beach 6 unit was on forced outage between April 3 and April 6, 2000 due to boiler tube leak. The outage records kept by AES also show this outage, although the start and end times differ by a couple of hours. However, the logs kept by the plant personnel suggest that the personnel planned this shutdown, and that the unit did not trip off. The boiler tube leak was not mentioned for two days. The review of evidence from control operator logs suggests that the forced outage reported to the CAISO was in fact a deliberate shutdown, and the boiler tube leaks were only mentioned two days after the reported start date.

[25] Note that a unit cannot immediately start generating power when it is on reserve shutdown, because start-up and ramp-up processes require some time for the unit to generate at full capacity.

Q. What are your findings regarding AES/Williams' outage of Alamitos Unit 7 on August 15, 2000?

A. The CAISO's SLIC logs show that (see Appendix PQH-C, Exh. No. CA-10, page 21) Williams declared Alamitos 7 to be on a forced outage on August 15, 2000 between 1:50 PM and 11:59 PM due to claimed NO_x limits. The Alamitos plant is owned and operated by AES, but through a contract between AES and Williams, known as the "tolling agreement," Williams has the exclusive right to market the plant's power and acts as its scheduling coordinator with the CAISO. The Alamitos control operator log for that date, maintained by AES, states at time 1406 (2:06 PM) "Williams requestS (*sic*) Unit 7 off."[26] This incident is troubling for two reasons. First, according to the plant's control operator log, the unit was not forced out of service, but was directed to go off line by Williams, its marketing company, and this direction was given shortly <u>after</u> Williams notified the CAISO that the unit was forced out of service due to NO_x limits. Second, even if the AES records had confirmed Williams's claim of a forced outage due to NOx limitations, Williams has admitted that NO_x limitations do not, in any case, constitute a valid basis for a unit outage under the tolling agreement.[27] Much of this outage took place during a CAISO declared Stage 2 Emergency.

[26] AES-A008037. (Exh. No. CA-303)
[27] Exhibit No. CA-162, pp. 29-30

Q. What are your findings regarding Dynegy's outage of El Segundo Unit 1 from August 30, 2000 through September 3, 2000?

A. According to the CAISO SLIC records, Dynegy put its El Segundo 1 unit on a scheduled outage between August 30 and September 3, 2000 to repair generator brush rigging. Note that the outage was scheduled on August 31 (one day late). As shown in Appendix PQH-C, Exh. No. CA-10 page 22, Dynegy's GADS records only show a 20 MW forced curtailment between August 11 and September 1, 2000 to prevent creep damage to IP rotor. Moreover, the unit was on reserve shutdown between August 30 at 9:16 PM and September 13 at 3:40 PM. In other words, Dynegy's GADS records do not confirm the outage reported to the CAISO. The plant control operator logs indicate that the unit was derated by about 20 MW due to rotor temperature limitations, and the brush rigging was performed on August 15. A log entry on August 30 at 1:28 PM shows that the unit was not needed due to low prices, and then the unit was shutdown on the same day at 9:16 PM. The evidence shows that the outage reported to the CAISO was due to low prices, not to perform the brush rigging.

Q. What are your findings regarding Mirant's outage of Pittsburg Unit 1 from October 18, 2000 through October 22, 2000?

A. As shown in Appendix PQH-C, Exh. No. CA-10 page 23, Mirant declared to the CAISO that its Pittsburg 1 unit was on forced outage between October 18 and October 22, 2000 due to external tube leak. However, Mirant's GADS data show that this outage ended on October 20, and that the unit was on reserve shutdown between October 20 at 5:35 PM and October 22 at 10:15 PM. The plant control operator logs also indicate the outage ended on October 20. The discrepancy between the company's own records and the SLIC logs suggests that Mirant waited for approximately two days to notify the CAISO about the end of the outage.

Q. What are your findings regarding Reliant's outage of Etiwanda Unit 1 from November 14, 2000 through November 16, 2000?

A. Reliant notified the CAISO that its Etiwanda 1 unit was on forced outage between November 14 and November 16, 2000 due to problems with the cooling tower. As shown in Appendix PQH-C, Exh. No. CA-10 page 24, this outage does not appear in Reliant's GADS records. Instead, the unit was recorded as on reserve shutdown between November 3 and November 16, 2000. According to the shift supervisor logs, the unit was "off - not required" until November 14. At 5:55 PM on the same day, the unit's start-up was aborted due to environmental concerns with the cooling tower. But the unit was still "off-not required" on November 15. The available evidence shows that Reliant did not view the Etiwanda 1 unit as needed during the Stage 2 emergency periods on November 14 and November 15.

Q. What are your findings regarding Duke's outage of Oakland Unit 1 from November 19, 2000 through November 22, 2000?

A. The CAISO SLIC records show that Duke reported to the CAISO that its Oakland 1 unit experienced a forced outage between November 19 and November 22, 2000 due to repairs in lube oil cooler and cooling fan. Although the original expected time of return was reported to be November 21, Duke later postponed the expected return date to November 27. But then Duke notified the CAISO on November 27 that the unit was actually available on November 22. As shown in Appendix PQH-C, Exh. No. CA-10 page 25, the company's outage records indicate that the unit was in fact on an outage, but that the outage ended on November 20 at 9:09 PM. The plant control operator logs confirm the GADS records, and note that the unit was available for full load on November 20 at 10:23 PM. Therefore, the plant's own records show that Duke waited for at least two days to notify the CAISO about the end of outage. Note that the CAISO declared a Stage 2 emergency on November 20, and Stage 1 emergencies on November 19 and 20.

Q. What are your findings regarding AES/Williams' outage of Redondo Unit 5 from December 19, 2000 through December 20, 2000?

A. According to the CAISO's SLIC records, Williams declared a forced outage at its Redondo 5 unit between December 19 and December 20, 2000 due to boiler tube leaks. As shown in Appendix PQH-C, Exh. No. CA-10 page 26, the

GADS records confirm the outage in this period. However, the plant control operator log entries raise suspicions. An entry by the control operator on December 19 at 7:18 PM put quotation marks around the outage reason as "Blr. Tube Leak". Moreover, the logs indicate that no boiler tube leaks were found after carrying out tests. Note that the CAISO declared a Stage 2 emergency on both days. Therefore, I consider this outage event highly suspicious.

Q. What are your findings regarding Reliant's outage of Etiwanda Unit 1 from December 28, 2000 through December 30, 2000?

A. According to the CAISO's SLIC records, Reliant declared its Etiwanda 1 unit on forced outage between December 28, 2000 at 8:59 AM and December 30, 2000 at 12:30 PM due to "cooling water tower work". As shown in Appendix PQH-C, Exh. No. CA-10 page 27, the GADS records do not mention any outage during this period. The shift supervisor logs do not indicate any outage related to the cooling water tower during this time period. The logs indicate that the unit was on stand-by status, and Reliant requested the unit to be online on January 2, 2001. The plants' internal records show that the plant was not forced out of service as Reliant had informed the CAISO.

Q. What are your findings regarding Reliant's outage of Etiwanda Unit 2 from December 28, 2000 through December 30, 2000?

A. According to the CAISO SLIC records, Reliant declared its Etiwanda 2 unit on forced outage between December 28, 2000 at 9:03 AM and December 30, 2000 at 12:30 PM due to "cooling water tower work". As shown in Appendix PQH-C, Exh. No. CA-10 page 28, the GADS records do not mention any outage during this period. The shift supervisor logs indicate that the work on Unit 2 East Cooling tower rise was completed on December 29, 2000 at 4:51 PM. The logs indicate that Reliant requested the unit to be online on January 2, 2001. The plants' internal records show that the outage reported to the CAISO ended on December 29, not on December 30.

Q. What are your findings regarding Reliant's outage of Etiwanda Unit 2 from January 25, 2001 through January 28, 2001?

A. According to the CAISO SLIC records, Reliant notified the CAISO that its Etiwanda 2 unit was on scheduled outage between January 25 and January 28, 2001 to repair vacuum leaks. As shown in Appendix PQH-C, Exh. No. CA-10 page 29, Reliant's GADS records indicate that this outage ended on January 26 at 8:35 PM, and the unit was on reserve shutdown until January 28 at 3:02 PM. The shift supervisor logs agree with the GADS records, and also indicate that the outage ended and the unit was released to Reliant on January 26 at 8:35 PM. Moreover, a log entry in the nightshift of January 26 flags the unit as "off-line not needed". The CAISO declared continuous Stage 3 emergencies during the January 26-28 period. The evidence shows Reliant did not declare the end of outage to the CAISO for approximately two days while the CAISO system was experiencing continuous Stage 3 emergencies.

Q. What are your findings regarding Mirant's outage of Pittsburg Unit 1 from March 8, 2001 through March 21, 2001?

A. The CAISO SLIC logs show that Mirant declared a forced outage at its Pittsburg 1 unit between March 8 and March 21, 2001 due to a boiler tube leak (see Appendix PQH-C, Exh. No. CA-10 page 30). The outage was declared at an end on March 21 at 4:47 PM. Mirant's GADS records confirm this outage for the most part, except the end date is March 20 at 2:15 PM (about one day earlier than the end of the outage reported to the CAISO). The plant control operator logs indicate the outage ended on March 20 at 2:15 PM, too. According to the operator logs, the unit could have been ready to generate after a 16-hour start-up period (by about 7:00 AM on March 21). Note that the CAISO issued a Stage 3 alert on March 20 between 9:17 AM and 2:30 PM, a Stage 2 alert on the same day between 12:01 AM and 9:59 PM, and Stage 1 emergencies on March 20 and 21. Therefore, the evidence shows that the end of the outage was declared to the CAISO a day later than the end date according to the company's own records.

Q. What are your findings regarding Reliant's outage of Ellwood from January 12, 2001 through April 10, 2001?

A. As shown in Appendix PQH-C, Exh. No. CA-10 page 31, Reliant declared to the CAISO that its Ellwood unit was on forced outage between January 12, 2001 at 5:50 PM and April 10, 2001 at 6:24 AM due to exciter troubles. Reliant's GADS records show that this outage ended on April 9 at 3:13 PM, and that this unit went into reserve shutdown at 3:35 PM. Although Reliant did not provide shift supervisor logs for the April 9-10, 2001 period, the available evidence suggests that the end of outage was not reported to the CAISO for more than twelve hours during peak hours.

Q. What are your findings regarding Reliant's outage of the Etiwanda Unit 1 from May 9, 2001 through May 14, 2001?

A. According to the CAISO's SLIC records, Reliant declared its Etiwanda 1 unit on forced outage between May 9, 2001 at 10:38 PM and May 14, 2001 at 1:25 PM due to boiler tube leak and water wall troubles. As shown in Appendix PQH-C, Exh. No. CA-10 page 32, Reliant's GADS records indicate that this outage ended on May 12 at 12:45 AM, and that the unit was on reserve shutdown after the end of outage. The available evidence suggests that the unit was not on a forced outage between May 12-14, but it was actually on reserve shutdown.

Q. What are your findings regarding Reliant's outage of Etiwanda Unit 5 from May 30, 2001 through May 31, 2001?

A. As shown in Appendix PQH-C, Exh. No. CA-10 page 33, Reliant declared to the CAISO that its Etiwanda 5 unit was on forced outage between May 30 and May 31, 2001. But Reliant's GADS data does not show any outage during this period. Instead, the GADS data indicate the unit was on reserve shutdown between May 30 at 5:30 PM and May 31 at 9:59 AM. The CAISO declared Stage 2 emergencies on May 30 and May 31. Reliant did not provide plant control operator logs for Etiwanda 5 during this period. But the evidence provided shows that the unit was declared to be on a forced outage on system emergency periods when the company's own records show that the unit was on reserve shutdown.

2. *__Anomalous Events__*

Q. Are there any other outages you find suspicious?

A. Yes. I identified two outage events that are anomalous.

Q. What are your findings regarding Dynegy's outage of El Segundo Units 1 and 2 from November 19, 2000 through December 5, 2000?

A. According to the CAISO's SLIC records, Dynegy's El Segundo 1 and 2 units were declared to be on forced outage between November 19 and December 5, 2000. The reason for the outage was Dynegy's inability to staff the units, because of staff vacation schedules. As explained in more detail in Appendix

PQH-D, Exh. No. CA-10 page 34, Dynegy's own GADS records indicate that the unit was on reserve shutdown between November 18 and December 1, 2000. Moreover, the plant control operator logs indicate that the unit was removed from service on November 18, because it was not needed. The control room of these two units did not have any staff to operate the units after that day. According to CAISO's SLIC logs, the CAISO requested the unit on November 19, but Dynegy declined the request. The CAISO declared a Stage 1 emergency on November 19, and then a Stage 2 emergency on November 20. Although Dynegy's putative reason for the outage is its inability to staff the units during system emergencies because of its staff's vacation schedules, there is reason to believe that commercial interests unrelated to employee relations motivated the outage.

Q. What are your findings regarding Reliant's outage of Etiwanda Unit 3 from March 30, 2001 through June 13, 2001?

A. The CAISO's SLIC records indicate that Reliant declared its Etiwanda 3 unit on forced outage between March 30, 2001 and June 13, 2001 due to boiler tube leak and SCR work (see Appendix PQH-D, Exh. No. CA-10 page 35). Although the original return date was April 2, 2001, Reliant later notified the CAISO that the expected date of return was still unknown. The CAISO had requested on March 29 that Reliant should return the unit back to service as soon as possible if the unit had to go on forced outage. After the outage started, Reliant notified the CAISO that the expected date of return was updated to June 11, 2001. Reliant told the CAISO that the outage was being extended due to financial reasons. It is very suspicious that an outage was extended for a total of two months due to "financial reasons" during a period with two Stage 3 emergency days and thirteen Stage 2 emergency days.

3. *Reserve Shutdowns During CAISO-declared Emergency Periods*

Q. Have you also examined the periods in which the Sellers' units were recorded to be on reserve shutdown during system emergencies?

A. Yes. I have. I have examined the reserve shutdown periods reported in the GADS data provided by Dynegy, Duke, Mirant, and Reliant.[28] By comparing these periods against CAISO-declared emergency periods, I found that some of these reserve shutdown events took place during the emergency periods. I also found instances in which the Sellers reported an outage in their units to CAISO when their GADS records show these units were on reserve shutdown.

Q. What is the importance of observing that a unit was on reserve shutdown during a CAISO-declared emergency period?

[28] AES did not provide any data on reserve shutdown events. Therefore, I could not investigate the reserve shutdowns on AES generating units.

A. That a unit was on reserve shutdown during a CAISO-declared emergency period is a singular and telling observation. As noted above, the CAISO only declares an emergency when the operating reserves are expected to fall below certain levels; i.e. when total available generation capacity is dangerously close to expected electricity demand. Remember, in a Stage 3 emergency, involuntary curtailment to customers (rolling blackouts) is required.[29] It is highly suspicious when a unit is on reserve shutdown when the available generation sources are dangerously low.

Q. What are your findings related to reserve shutdowns during emergency periods?

A. The results based on my comparison of CAISO-declared emergency periods[30] to reserve shutdown events reported by Dynegy, Reliant, Mirant, and Duke are shown in Appendix PQH-E Exh. No. CA-10 pages 36 - 38.

D. CONCLUSIONS

Q. What are your conclusions for this first part of your testimony?

A. I conclude that in at least fourteen incidents spanning about thirty days, Dynegy, Reliant, Mirant, Duke and AES/Williams reported to the ISO that

[29] http://www.caiso.com/aboutus/glossary/index.html
[30] Source: CAISO, System Status Log. http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls

generating units were unavailable due to required maintenance or repairs or other limitations when their own internal records show that the units were, in fact, available. Eight of these incidents occurred during ISO declared system emergencies. I further conclude that there are twenty-two instances in these same Sellers' records that show they placed their units on Reserve Shutdown (shutdown for economic reasons) during CAISO-declared emergency periods and thus kept them out of the market even though they were operable. This form of physical withholding would not only have tended to raise prices, but it also made it more difficult for the CAISO to maintain system reliability.

III. PART II - THE EXERCISE OF MARKET POWER THROUGH THE BIDDING BEHAVIORS OF CALIFORNIA'S MAJOR GAS FIRED GENERATORS

Q. Have you assessed the bidding behavior of the major generation Sellers in California to see if there is evidence of the exercise of market power?

A. Yes. I sought to determine if these sellers altered their bids in ways that were not related to costs but were instead in response to changes in supply/demand conditions and changes in a particular seller's position in the market, that is, the seller's ability to profit from price increases. The FERC has itself recognized this type of behavior as indicative of market power, a position that is well-supported in economic theory. Specifically, FERC found in its April

26, 2001 Order in this proceeding that hockey-stick bids and bids that vary with system conditions and not changes in underlying price are anti-competitive.

First, bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit are prohibited. An example of this bidding practice is the so-called "hockey stick" bid where the last megawatts bid from a unit are bid at an excessively high price relative to the bid(s) on the other capacity from the unit. A variant of this pattern could be a single unit in a portfolio that is bid at an excessively high level compared to the remainder of the portfolio, without any apparent performance or input cost basis.

A second category of prohibited bids is those bids that vary over time in a manner that appears unrelated to changes in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis. An example of this is a bid that appears to change only in response to increased demand or reduced reserve margins, particularly if the timing of the bid is related to public announcements of system conditions or to timing of outages in a participant's portfolio[31].

[31] San Diego Gas & Electric Co., et al., 95FERC|61,115 (2001) (April 26, 2001 Order), p. 17.

Various sellers questioned that ruling on rehearing, contending that such bidding practices were legitimate. The Commission rejected these contentions flatly, stating:

> *"We will not tolerate abuse of market power or anticompetitive bidding or behavior. Emblematic of these practices is the now well-publicized bid of $3,880/MWh by Duke Energy."* ....
>
> Public utility sellers' market based rate authority will be subject to potential revocation if they are found to have engaged in inappropriate behavior. Further, WSCC public utility sellers' market-based rate authorizations are hereby conditioned on agreeing to potential refunds for overcharges resulting from anticompetitive behavior[32].

Q. Why is bidding above a unit's marginal cost an indication of the exercise of market power?

A. Bidding above marginal costs inherently is indicative of the exercise of market power. Recall that California's real-time electricity market is a uniform price auction where every seller receives the market-clearing price. A seller that

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[32] San Diego Gas & Electric Co., et al., 95FERC|61,418 (2001) (June 19, 2001 Order), p. 37.

bids above marginal costs can have only two purposes in doing so and both imply that it is exercising market power. Either the seller has a reasonable expectation that its bid will be accepted, implying there is insufficient supply to meet the current level of demand, or, it hopes to restrict the supply offered up to the market by pricing above the market clearing price. Both of these imply the seller is exercising market power to increase its revenues by attempting to raise prices. This is to be distinguished from the increase in prices that occurs in competitive markets when more expensive supply is brought forward as a result of increasing levels of demand.

Q. Which sellers did you examine?

A. I examined the same Sellers as in Part I of my testimony.

A. OVERVIEW OF BID CHARACTERISTICS

Q. Have you examined the bids in terms of their historical pattern?

A. Yes. I have included graphs that depict the Sellers' bids, my estimates of marginal costs and, thus, the mark-up over marginal costs for the Sellers. One set covers the period from May 1, 2000 until October 1, 2000, and a second set covers the period October 2, 2000 until December 7, 2000, and a third set that begins on December 8, 2000 and ends on January 18, 2001. Prices, bids and costs are weighted daily averages for the sixteen-hour on-peak period. Also, on these charts are lines depicting the price cap level as well as the average clearing price in the real time market. There are several simple and straightforward observations that can be made. First, some of the margins are nothing less than extraordinary. The margins for some Sellers are on the order of literally hundreds of dollars per megawatt, and clearly are not remotely related to their marginal costs. Second, it appears that these very large mark-ups above marginal costs preceded the price spikes in May and June 2000 that many see as the beginning of the market crisis that struck California. Indeed the correspondence between the inflated bids of some of the Sellers and prices during the spike periods suggest that spikes occurred when the market was forced to accept such bids. Look, for example, at the match between the Reliant bids and market prices June 20-22, 2000 and that between prices June 26-29, 2000 and the bids of Mirant, Dynegy and AES/Williams. Third, the "hard" price caps do appear to have been effective, particularly at the $250 level, in that they reduced opportunism relating to spiked bidding at higher levels. Fourth, from my casual examination of these data, the lowered cap not only reduces the level, but also the volatility/spread of the bids. Fifth, the "soft" cap seems to have been entirely ineffective in reducing the mark-ups over marginal costs. Nearly all Sellers' mark-ups increase substantially when the soft cap is instituted. Finally, one can not help but note the difference in Duke's bidding behavior from that of the other Sellers during the first of the two periods covered in the graphs. Duke mark-ups above costs, although substantial, are much smaller than those of the other Sellers. And except for its bids on July 18-20, 2000 they do not seem to have been associated with price spikes. During the later price cap period, however, Duke's mark-ups above costs become extremely aggressive.

B. ANALYSIS APPROACH

Q. What was the focus of your analysis?

A. I examined the Sellers' bid mark-ups in excess of the marginal costs of providing power from their units. I measure the bid mark-ups against marginal costs because in competitive markets a seller would, by virtue of the competition from other sellers in the market, be compelled to bid their marginal cost if they wish to sell their product. Thus, the mark-up over marginal costs and the frequency of bids exceeding marginal costs is a measure of the degree to which a seller has the ability to influence prices and, therefore, is indicative of the lack of competition in the market. The percentage mark-up of prices over marginal costs is a well-known measure of market power and is known as the Lerner Index.

Q. Was there any particular emphasis in your examination of the Sellers' mark-ups over marginal costs of the bids?

A. Yes, I examined the relationship of such bid mark-ups to market conditions and to each individual Seller's position in the market at the time of the bids. If the bid mark-ups of the Sellers is independent of their costs, then clearly they are capable of exercising market power. However, I examined the relationship between the bid mark-ups and what I call condition variables, specifically the tightness of the market and the depth of Sellers' positions in the market, to see if there was a systematic relationship between them. If the bid mark-ups increase with the tightness of the market or with the depth of Sellers' holdings in the market, then clearly the Sellers not only possess market power but they are also exercising it intentionally based upon opportunities presented in the marketplace and their own ability to capitalize upon increased prices.

Q. Why did you choose to examine these two particular features of the market, market tightness and Sellers' market position?

A. I chose these two features of the market to examine because one speaks to a Seller's opportunity to exercise market power while the other speaks to a Seller's motive. As the Commission has recognized, the tighter the market, the easier it is for a seller that has market power to exercise it. A market whose demand is large relative to the resources available to supply that demand is relatively easy prey for a Seller with resources of significance in size to the market. The FERC has noted that when markets are particularly tight, even relatively small Sellers may influence the price. So tightness is used in my analysis as a measure of opportunity to raise prices relative to costs.[33]

On the other hand, the more generation a Seller has in the market to benefit from a price increase, the greater the motivation to raise prices. As Professor Paul Joskow at Massachusetts Institute of Technology has described[34], bidder profits from unilaterally withholding supply to raise prices depend upon the tradeoff between sales volumes lost by increasing the price and the increased revenues realized on the remaining sales at the higher price. Obviously the more inframarginal generation the bidder has in the market the greater the leverage of any price increase and thus the greater the incentive to mark up bids.

Q. Since your calculations are sensitive to your estimate of costs and the bids themselves, how have you tried to address these issues in your analysis?

A. I have attempted to be as conservative in my approach as is feasible. My cost estimates include a variety of non-fuel-related costs such as permit costs for NO_x emissions, as well as a factor for maintenance. In addition, my choice of prices for gas is known to be at the high end of the range of possible values[35]. Further, we look only at the bids in the real-time market that were part of the

[33] San Diego Gas & Electric Co., et al., 93FERC 61,121 (2000) (November 1, 2000 Order), p. 33.
[34] Joskow, Paul and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000," *The Energy Journal*, Volume 23 (2002), Number 4, pp. 17-19.

so-called "BEEP" stack. This necessarily excludes sales that were accepted by the CAISO "out of market ('OOM')" and, thus, were higher than the bids in the BEEP stack. The choice of the real time market also eliminates most concerns regarding opportunity costs as they might affect marginal costs since, in real time, other opportunities are for the most part unavailable.

C. STATISTICAL ANALYSIS OF BID MARKUPS

Q. How did you perform your analysis?

A. My analysis is structured so as to relate the real time bid of each of a Seller's generating unit to: 1) its underlying costs; 2) the condition of the market; and 3) the amount of generation that the Seller has in the market at a price below that of the particular bid being evaluated. If the Seller based its bids solely on unit costs, then the market's condition and the Seller's market position should have no ability to explain any variations in the bids. That is, the bid would depend <u>only</u> on the generating unit's underlying costs. I chose the real time market because there are no opportunities for bidding into other markets, as there would be if I had examined the day-ahead market, and, thus, I eliminated most of the confounding effects that might arise from the possibility of opportunity costs. The real-time market is of interest also because, as Drs. Fox-Penner and Berry demonstrate, Exh. Nos. CA-1 and CA-7, over time Sellers

[35] San Diego Gas & Electric Co., et al., 95FERC 61,418 (2001) (June 19, 2001 Order), pp. 28-31.

appeared to shift their bids from the Day Ahead market to the real-time imbalance market. The data suggests such a move was made because it became clear to the Sellers that it was easier to manipulate the real-time market than the Day Ahead market to their advantage.

Q. How did you quantify the variables in your analysis?

A. I begin discussing the quantification of these variables by focusing on the Sellers' unit bids into the real-time energy market. These bids are taken from publicly available data of the California Independent System Operator. The CAISO enters all of the spin, non-spin, replacement, and supplemental energy bids into the Balancing and Ex-Post Pricing ("BEEP") software that it uses to operate its real-time energy market. Each step of each bid is placed in a merit order to form the so-called "BEEP stack," which is the supply curve from which the real-time price is determined. The real-time energy market is operated under a uniform market clearing price rule. Under that auction rule, the highest cost unit that is dispatched to meet the market's demand sets the price for all units in the market. The CAISO has supplied the information needed to decode the unit identifiers on this data set and, thus, the bids can be assigned to the appropriate generating unit and Seller. I have also used information about units that are already scheduled to dispatch, which includes units that have been scheduled from the Hour Ahead and Day Ahead markets.

Q. How do you calculate marginal costs?

A. In the calculation of marginal costs, each generating unit is represented by a ten-point incremental heat rate curve. This allows a very accurate representation of the fuel component marginal costs. The fuel cost calculation used California spot index gas prices as set forth in the current FERC Refund methodology.[36] They are *Gas Daily*'s published prices - PG&E Citygate for NP15 plants and Southern California Large Packages for SP15 and 2P26 plants. In addition, the costs include variable operations and maintenance costs other than fuel. Dr. Reynolds provided the cost information (Exh. No. CA-6). In addition, some generating units face charges with respect to their nitrous oxides ("NO_x") emissions. Dr. McCann has supplied that information and further discusses other environmental issues that affect generating unit operations (Exh. No. CA-11). Charges or fees for these permits are then added to a unit's marginal costs when appropriate.

No capital costs were included, nor were start-up or no-load costs. Those costs should be recovered by either infra-marginality of the unit's bid, i.e. the bid is successful and lower than the market, or through sales into the ancillary services markets.

Q. How do you calculate bid margins?

A. I do not calculate bid margins, per se. I accomplish the goal of having a variable that represents bid margin by using only bids that exceed marginal costs. By estimating a mathematical relationship in which the bids with positive mark-ups depend upon their associated marginal costs, I permit the changes in the costs of producing power, i.e. their marginal costs, to "explain" the variations in the bids. This removes the variation in the bids accountable by changes in their marginal costs. Any remaining variations in the bids are then accounted for by the other variables included in my statistical estimation of this mathematical relationship, the market conditions variables adumbrated above and more fully described below.

Q. How do you represent the Sellers' incentives resulting from their having a market position?

A. To capture the effect of a Seller having a portion of its generation already in the market, I calculate the number of megawatts that the Seller has bid into the market at a price less than that of the instant bid. I refer to this as the Seller's position in the real time market as measured by the total megawatts (from all units) that the seller already has in the real-time bid stack. If the instant bid were successful (i.e. the real-time market price is equal to or greater than this bid), then all megawatts bid into the market below this bid would receive the price of the instant bid. Thus, I should expect that if the Sellers were

[36] San Diego Gas & Electric Co., et al., 95FERC|61,418 (2001) (June 19, 2001 Order), pp. 28-31.

strategically bidding, then the larger the position the seller has in the market, the higher the bid. In the calculation of this variable all of the Seller's bids in the BEEP stack are included, not just those with positive margin. This variable also captures the so-called "hockey stick" bidding practice. To account for the impact of the Sellers having contracted some of their capacity forward, I multiply this market position variable by an estimate of the percentage of their capacity not contracted forward based upon information from the CAISO[37].

Q. What do you use as a variable to represent the condition of the market?

A. As a measure of market conditions, I use the ISO load in the hour of the bid. Again, this is public information obtainable from the CAISO. If the Sellers have the capability to exercise market power, then it is likely that their bids should be influenced by market conditions. In particular, should the data indicate that the mark-up over marginal costs rises with increases in market demand, then this is a clear indication that the generators are exercising their market power. Note also, that generators have at their disposal not only the capability to exercise power by financially withholding power, but also physically withholding power from the market. This may reduce this variable's impact.

[37] Exh. No. CA-270.

Q. Do you include any other variables in the relationship you statistically estimate?

A. Yes, I include a set so-called "indicator" or "zero-one" variables that, for each of the peak hours, take the value of unity when it is one of the peak hours and is zero otherwise, and a similarly structured variable which is unity if it is a weekday observation and zero otherwise. This is aimed at capturing some of the natural variation in demand that occurs all year round.

Q. Over what periods do you perform this analysis?

A. In performing the statistical analysis, I have broken up the period January 1, 2000 until January 18, 2001 into subperiods. Those subperiods are: 1) January 1 through April 30; 2) May; 3) June; 4) July 1 until August 6; 5) August 7 until August 31; 6) September 1 until October 1; 7) October 2 until December 8; and 8) December 9, 2000 until January 17, 2001. The first period had relatively low price volatility, but there is anecdotal evidence that there were some initial attempts at testing market manipulation strategies in this period. May evidenced the first serious price spikes, with the third period, June, experiencing even greater volatility. On July 1, 2000 the bid cap was reduced to $500 and remained so until August 6, 2000. On August 7, 2000 the bid cap was further reduced to $250 and remained so until December 8, 2000 when the $250 "soft" bid cap was introduced. That soft cap was further reduced to $150 on January 1, 2001 and remained so for the period I examine. Also, once the soft cap was introduced, start-up and no-load costs for Sellers were also potentially recoverable as part of their bids. I have divided the August through December period into three subperiods because this seems to provide reasonable homogeneity in apparent market conditions. I truncated the period beginning December 8, 2000 at January 17, 2001 because at that point the California Department of Water Resources ("CDWR") contracts come into play and the underlying economics of the real- time market change.

D. RESULTS

Q. What are the results of your analysis with respect to how the units' margins vary with respect to the Sellers' market position?

A. For the periods examined, the market position variable is uniformly statistically significant and positive for all Sellers for all periods[38]. (See Appendix PQH-J, Exh. No. CA-10, p. 158) This means that the Sellers' increase their units' bids more rapidly than costs as a function of how much they have already bid in at lower prices. As a generator enlarges its position in the market, its ability to benefit from a rise in market prices also increases. Further, this relationship between bids and market position is independent of scarcity since that is explicitly measured by another variable (described below). Thus, the fact that the bids increase when Sellers' have an increasingly large position in the market, and that they do so independently of market scarcity, evidences intentional exercise of market power, because the Sellers used their power precisely when it profited them the most.

Q. What are the results of your analysis with respect to changes in market conditions?

A. The market tightness variable over the periods examined generally has the sign that would be expected if Sellers attempted to increase their margins in response to market conditions, although not as uniformly in sign or significance as the market position variable. Although I might expect that as demand rises, prices in the market should also rise because more expensive resources will be needed to meet such demand. However, my dependent variable is not the unit's bid price per se, but rather I have restricted my attention to those bids that are greater than my estimate of marginal costs. That the margin rises with demand is not predicted by economic theory, but is a function of Sellers advantaging themselves of the market's condition to increase their profitability. As one Seller's e-mail stated, "Load is avg above 40,000 during peek (*sic*). So, submit revised supp bids and "stick-it to 'em!!!"[39] (emphasis in the original).

[38] I have not performed the statistical analysis for Duke for May because of insufficient data.
[39] MIR00000998335. (Exh. No. CA-141)

Q. Is there the potential that these two effects, market tightness and market position, could combine in ways to amplify their effect?

A. Absolutely. I would expect that during periods in which the market was tight more of a Seller's generation would have been bid into the market, thus increasing the incentive of the Seller to find some mechanism to withhold and drive its profitability up.

E. CONCLUSIONS

Q. What are your conclusions?

A. As a result of my analysis I have three conclusions. First, all of the Sellers submitted bids significantly above marginal costs. This occurs uniformly across all of the Sellers. That Sellers found it profitable to bid above marginal costs, and quite substantially so at times, in itself implies that the market was not competitive and that the Sellers were at least taking advantage of the situation, if not themselves elevating prices artificially. In effect, through their apparent market power, they were able to bid well above marginal costs and economically withhold supply. Withholding can be either physical (withholding operable generation from the market) or economic (bidding units far above their marginal costs and, thus, precluding their economic dispatch). Drs. Reynolds and Berry further discuss specific methods of withholding and witness Fox-Penner discusses various manipulative strategies that have the effect of withholding supply from the auction markets. Appendix PQH-H, Exh. No. CA-10, pages 103-117 depicts the megawatt-weighted margins of the Sellers indicates how divergent from marginal costs their bids were.

My second finding is that Sellers' markups over costs significantly increased with Sellers' market positions. That is, a seller's bid markup over its generating unit's marginal costs increased significantly with the total volume of a Seller's other real-time bids that are already in the bid stack (i.e. that are below the instant bid). The results clearly document that there is a strong (statistically significant) relationship between markups and the Seller's ability to benefit from an attempt to increase market price. A fairly straightforward strategy on the part of a seller is to bid its highest cost units significantly higher than their marginal costs. This is often referred to as "hockey stick" bidding and can potentially have one of two effects if successful. If the bid is chosen, it raises the profit margins of all other bids (from all units) that are already in the bid stack. Even if the bid is not chosen, it can have the effect of reducing available economic supply and, thus, can raise prices by forcing the choice of more costly units that would otherwise not have been dispatched. Further, the incentive to bid this way increases with the amount of generation that a seller has in the bid queue. As the amount of capacity already positioned in the real-time market increases, the greater the benefits from the manipulation of market prices and, thus, the greater the incentive to bid based on increased mark-ups over marginal costs. Thus, the larger the seller's position in the real-time market, the higher I expect the bid to be above marginal cost. The results show that this is in fact the case. As noted above, this is an indication that Sellers acted intentionally in marking up their bids.

My third conclusion is that Sellers' markups over costs significantly increased as market conditions tightened (or were perceived to tighten). That is, an individual bid's markup over its marginal costs increased significantly as the Sellers became aware of tight market conditions. It is important to distinguish between the expected rise in bids as demand increases because of the need to utilize less frequently operated and more expensive to operate generating units and an increase in the mark-ups over marginal costs of bids. The former is an attribute of a competitive market, but the latter is only characteristic of uncompetitive markets. This result holds true even after the imposition of the soft bid caps. Although bids above the soft cap cannot set the market-clearing price when the soft price cap is imposed, this variable generally remains positive and significant statistically.

Q. Does this conclude your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant	)	
v.	)	Docket Nos. EL00-95-069
Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, Respondents.	)	
Investigation of Practices of the California Independent System Operator and the California Power Exchange.	)	Docket Nos. EL00-98-058

AFFIDAVIT OF PHILIP HANSER

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

Executed on February 24, 2003.

[Name]

Index of Relevant Material Template

Submitter (Party Name)	California Parties
Index Exh. No.	CA-10
Privileged Info (Yes/No)	Yes
Document Title	Prepared Testimony of Philip Hanser
Document Author	Philip Hanser
Doc. Date (mm/dd/yyyy)	03/03/2003
Specific finding made or proposed	Units were falsely reported to the ISO that generating units were forced out of service for mechanical reasons when the plant's own records show that the plant was capable of normal operation. Units were placed on "reserve shutdown" when no maintenance was required, during times when the ISO had declared a system emergency. Units were withheld by not bidding the output into the market even though the plant was fully operational. This withholding behavior occurred during numerous system emergencies. Generators withheld generation from the market by bidding high, and in excess of its costs, so as to deliberately price itself out of the market.
Time period at issue	a) before 10/2000; b) between 10/2000 and 6/2001
Docket No(s). and case(s) finding pertains to *	EL00-95 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	In at least fourteen incidents spanning about thirty days, a number of entities reported to the ISO that generating units were unavailable due to required maintenance or repairs or other limitations when their own internal records show that the units were, in fact, available. Eight of these incidents occurred during CAISO-declared system emergencies. There were at least twenty two instances in these same Sellers' records tht show they placed their units on Reserve Shutdown during CAISO declared emergency periods even though they were operable. Such forms of physical withholding would not only raise prices, but it also made it more difficult for the CAISO to maintain system reliability.

Party/Parties performing any alleged manipulation	Dynegy, Reliant, Mirant, Duke and AES/Williams

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

PHILIP HANSER — Principal

Philip Hanser is a Principal at *The Brattle Group* in its Cambridge office. Mr. Hanser provides consulting support in the areas of economics and business analysis, strategic planning and other business issues, with an emphasis on conceptual and quantitative analysis. His practice includes assistance on issues ranging from industry structure and market power and associated regulatory questions, to specific operational and strategic questions, such as transmission pricing, generation planning, tariff strategies, fuels procurement, environmental issues, forecasting, marketing and demand-side management, and other management issues. He has also provided support to utilities in insurance recovery of environmental liabilities arising from former manufactured gas plant sites.

He has appeared as an expert witness before the Federal Energy Regulatory Commission, the California Energy Commission, the New Mexico Public Service Commission, the Public Service Commission of Wisconsin, the Public Service Commission of Vermont, and the Public Utilities Commission of Nevada. He has also presented before the National Association of Regulatory Utility Commission and the New York State Energy Research and Development Authority. Prior to joining *The Brattle Group*, his past employment experience included a number of different academic positions and serving as the Manager of the Demand-Side Management Program at the Electric Power Research Institute. He has been published widely in leading industry and economic journals and testified frequently before regulatory agencies. Mr. Hanser has taught at the University of the Pacific, University of California at Davis, and Columbia University, and guest lectured at the Massachusetts Institute of Technology and Stanford University.

REPRESENTATIVE RECENT EXPERIENCE

- For a power marketer, provided expert testimony to the FERC for its market-based rate authority application.

- For the Pennsylvania—New Jersey—Maryland Interconnection, LLC (PJM) he co-authored the first annual report on the state of its markets. The report included an assessment of the Market's competitiveness and potential structural deficiencies, and identified potential instances of market abuse.

- For PJM, he developed an ensemble of metrics for assessing market power in its markets. The metrics included an early warning system to permit PJM interventions into market abuse at the earliest possible stage.

- For PJM, he developed software for unilateral market power assessment and assisted PJM in its preliminary implementation. Its use was demonstrated with an incident involving potential market power abuse by PJM members.

- For NSTAR, he provided expert testimony before the FERC with regard to the necessity of imposing bid caps on the New England electricity market.

- For NSTAR, he provided expert testimony at the FERC in their intervention of the granting of market-based rate authority to a New England generator.

- For NSTAR, he provided expert testimony on the appropriate rates for generators during transmission upgrades or enhancements requiring substantial and sustained reduction in transfer capability.

- For Nevada Power Company, he provided expert testimony before the FERC for its market-based rate authority application.

- For a European transmission company, he provided an analysis of the likely development of the European electricity market. He also assessed the market implications for the transmission company of modifications to the transmission grid.

- For a power marketer and developer of independent power projects in Great Britain, he assisted in the preparation of comments on proposals by the U.K. pool regarding the pricing of transmission losses and the role of demand-side bidding.

- For Sierra Pacific Resources Company, he provided expert testimony before the Public Utilities Commission of Nevada and the FERC, regarding the market power implication of generation asset divestiture required for the merger of Sierra Pacific Power and Nevada Power Company.

- For the Public Service Company of New Mexico, he provided expert testimony before the Public Utilities Commission of New Mexico regarding forecasted growth of the El Paso and Juarez, Mexico markets.

- For Vermont Public Service, he provided expert testimony on the impact of its demand-side management programs before the Public Service Commission of Vermont.

- Before staff members of the FERC, he assisted in the development of a review of the implications of the restructuring in transmission assets' cost of capital.

- For Southern California Edison, he submitted testimony before the FERC describing the implications for the electricity market of the manipulation of gas market prices.

- He co-authored a report assessing the reliability implications of the New York Independent System Operator's (NYISO) modification of its rules regarding installed capacity.

- For a Midwest utility, he examined the implications of differing configurations of the independent system operator on potential market power concerns. Assessed the liability risk of an insurance company that provided coverage relevant to a mass tort suit.

- Assessed the potential liability of a utility under the Clean Air Act's New Source Review.

- Assisted a U.S. electric utility in the preparation of a bid proposal to an industrial firm for the leasing of a portion of a new power plant. The assignment included risk analysis of the proposal, assessment of financial and rate impacts, and market assessment of competitors' potential offerings.

- For a U.S. electric utility, he assisted in the valuation of generation assets for use in its testimony on stranded costs. This included developing a financial model to determine the generation assets' market value, development of a convolution algorithm to convert market scenarios into a probability distribution of asset values, and statistical analysis of the relationship of the utility's generation assets' operating costs in comparison to its competitors. The assignment also included testimony preparation, interrogatories, and rebuttals.

- For a U.S. electric utility, he assisted in the development of a legislative and regulatory strategy with regard to restructuring. This assignment included generation asset valuation in a competitive market, development of stand-alone transmission and distribution rates under cost-of-service and performance-based regulation, and estimation of strandable costs.

REPRESENTATIVE PAST EXPERIENCE

- For a gas utility, he assisted in the development of potential manufactured gas liabilities for use in insurance recovery. For this assignment, he assisted in estimating potential recovery under a variety of insurance allocation theories and estimated the risk distribution of the estimates.

- He assisted a gas utility in the development of an assessment of the announcement effect of environmental liabilities on its cost of capital. This assignment included estimation of changes in betas for pre- and post- environmental liability announcement.

- For an international development bank, he assisted in a generation resource needs assessment for an Eastern European country as well as a determination of alternative means to meet those generation needs. This assignment included an evaluation of the impact of privatization on the country's economy, its import and export sectors and future development of Russian electricity and gas resources.

- For a California utility, he supervised short- and long-term forecasts of sales and peak demand for use in resource and corporate planning. He supervised and helped prepare forecast documentation for public hearings before the California Energy Commission and represented the utility to the Commission on the forecast. He supervised the design and implementation of long-term strategic planning and financial models for the utility, and prepared both marginal and embedded cost of service studies for the utility and assisted in their use for the design of customer rates. He evaluated the impact of energy conservation programs and legislation on long-term system resource requirements. Designed and implemented the residential survey of appliance holdings and commercial customer equipment survey. He also designed and implemented the load research survey for use in PURPA 133 submittals and cost of service studies.

- For the Electric Power Research Institute (EPRI), he was responsible for developing and directing a research program to provide electric utilities the following capabilities: marketing, marketing research, pricing and rate design, integrated resource planning, capital budgeting, environmental impacts of electric utilities and end-use technologies, load research, forecasting, and demand-side management through software tools, database development and technology development. He served as the final project manager of the Edison Electric Institute (EEI), Natural Rural Electric Cooperatives Association (NRECA), American Public Power Association (APPA), and National Association of Regulatory Utility Commissioners (NARUC) jointly sponsored Electric Utility Rate Design Study (EURDS). Represented the Institute before various regulatory commissions, Federal agencies, and utility executives. He served on the Environmental Protection Agency's advisory committee for the Clean Air Act Amendments. He also served as the operating agent for Annex IV, Improved Methods for Integrating Demand-Side Options into Utility Resource Planning, of the International Energy Agency Agreement on Demand-Side Management.

- For the investor-owned utilities of Wisconsin, he provided testimony before the Public Service Commission of Wisconsin on the cost of capital.

ACADEMIC HISTORY

Guest Lecturer, Energy Laboratory Short Courses, Massachusetts Institute of Technology, Cambridge, MA	1997-1998
Visiting Lecturer, Department of Economics, University of California, Davis; Davis, CA	1981-1982
Assistant Professor, Department of Economics and Mathematics, University of the Pacific, Stockton, CA	1975-1980
Ph.D. Candidacy Requirements Completed, Columbia University, NY	1975
Phil.M. (Economics and Mathematical Statistics) Columbia University	1975
A.B. (Economics and Mathematics) The Florida State University, FL	1971
Time Series and Econometric Forecasting, University of California at Berkeley Engineering Extension Course	September 1979
Data Analysis and Regression, American Statistical Association Short Course, San Diego, CA	August 1978

PROFESSIONAL MEMBERSHIPS

American Statistical Association, Member of Committee on Energy Statistics, 1993-1999
Institute of Electrical and Electronics Engineers
Association of Energy Service Professionals, Board Member, 1991-1995
Journal of ADSMP, Editor, 1995
American Economic Association

HONORS

Who's Who in the West	1984
Teaching Incentive Award, University of the Pacific	1979
Outstanding Young Men of America, Junior Chamber of Commerce	1980
Teaching Assistantship in Econometrics, Columbia University	1974
National Science Foundation Research Traineeship	1972-1974
Undergraduate and Graduate Research Assistantships, Florida State University	1968-1972
Omicron Delta Epsilon, Economics Honor Society	1971

PUBLICATIONS AND PRESENTED PAPERS

"Does SMD Need a New Generation of Market Models? Or How I Learned to Stop Worrying and Enjoy Carrying a Pocket Protector," SMD Conference, Washington D.C, December 5, 2002.

"Standard Market Design in the Electric Market: Some Cautionary Thoughts," SMD Conference, May 10, 2002, Chicago, Illinois.

"The Design of Tests for Horizontal Market Power in Market-Based Rate Proceedings" (with James Bohn and Metin Celebi), *The Electricity Journal*, May 2002.

"The State of Performance-Based Regulation in the U.S. Electric Industry" (with D.E.M. Sappington, J.P. Pfeifenberger, and G.N. Basheda), *The Electricity Journal*, October 2001.

"Deregulation and Monitoring of Electric Power Markets" (with R.L.Earle and J.D. Reitzes), *The Electricity Journal*, October 2000.

"Lessons from the First Year of Competition in the California Electricity Market" (with R.L.Earle, W.C. Johnson, and J.D. Reitzes), *The Electricity Journal*, October 1999.

"In What Shape is Your ISO?" (with J.P. Pfeiffenberger, G.M. Basheda and P.S. Fox-Penner), *The Electricity Journal*, Vol. 11, No. 6, July 1998.

"What's in the Cards for Distributed Resources?" (with J. P. Pfeifenberger and P.R. Ammann), in Special Issue of *The Energy Journal, Distributed Resources: Towards a New Paradigm of the Electricity Business*, January 1998.

"One-Part Markets for Electric Power: Ensuring the Benefits of Competition" (with F.C. Graves, E.G. Read, and R.L. Earle), in *Power Systems Restructuring: Engineering and Economics*, ed. M. Ilic, F. Galiana, and L. Fink, (Boston, MA: Kluwer Academic Publishers, 1998)

"Power Market Price Forecasting: Pitfalls and Unresolved Issues" (with R.L. Earle and F.C. Graves), forthcoming in *The Energy Journal.*

Five EPRI reports and approximately 20 articles in EPRI Reports and Conference Proceedings.

"Insurance Recovery for Manufactured Gas Plant Liabilities" (with G.S. Koch and K.T. Wise), *Public Utilities Fortnightly*, April 1997.

"Real-Time Pricing-Restructuring's Big Bank?" (with J.B. Wharton and P. Fox-Penner), *Public Utilities Fortnightly*, March 1997.

"Load Impact of Interruptible and Curtailable Rate Programs" (with D.W. Caves, J.A Herriges, and R.J. Windle), *IEEE Transactions on Power Systems*, Vol. 3, No. 4, November 1988.

"Estimating Hourly Electric Load with Generalized Least Squares Procedures" (With N. Toyama and C.K. Woo.), *The Energy Journal*, April 1986.

"Transfer Function Estimation Using TARIMA," *SAS User's Group International, 1982 Proceedings*. Cary, North Carolina: SAS Institute. Inc., 1982.

"Invited Editorial Response to Behavioral Community Psychology: Integrations and Commitments," by Richard Winett, *The Behavior Therapist* 4(5), Convention, 1981.

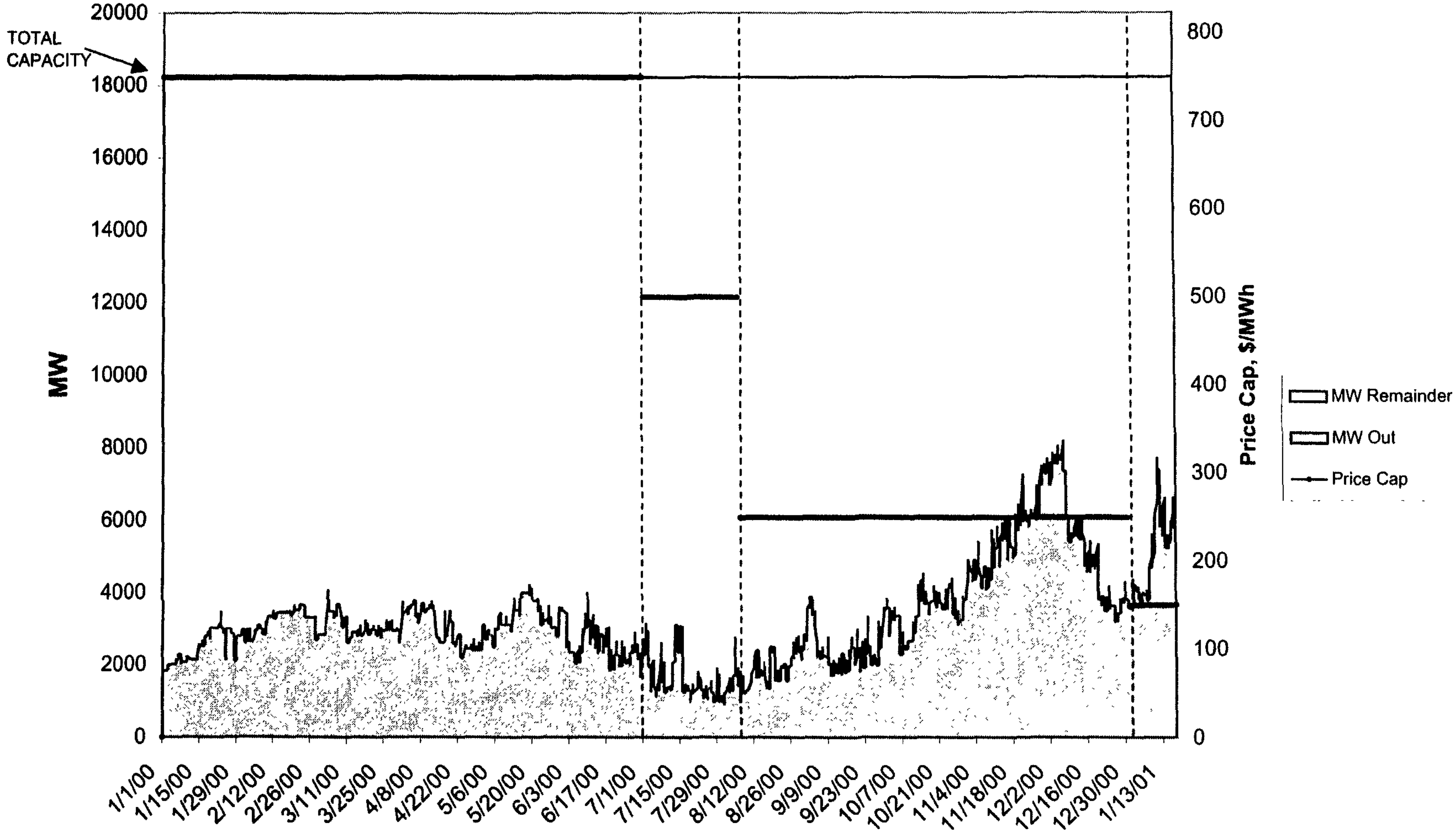
Statistics Through Laboratory Experiences (with D. Christianson and D. Hughes), Stockton, CA: University of the Pacific 1976-1977.

"Unsolved Advanced Problem," *American Mathematical Monthly*, May 1975.

"Multiattribute Utility Theory and Earthquake Mitigation Policy" (with T. Munroe), Western Economic Association Conference, June 1978.

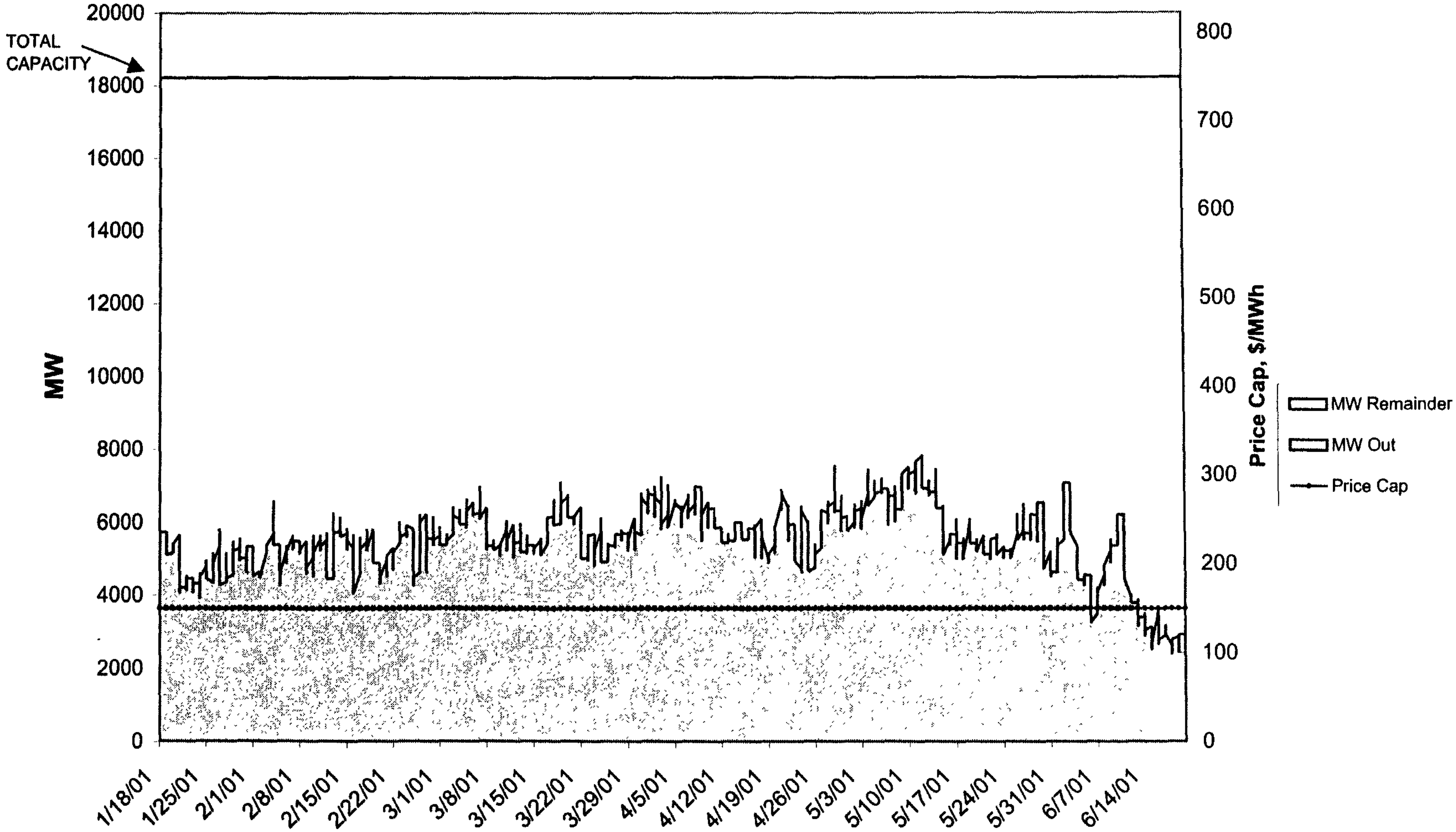
"Introduction to Multivariate Data Analysis Techniques," Bureau of Applied Social Research, Columbia University, New York, NY, 1973.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Big-Five Units
January 2000 - January 18, 2001



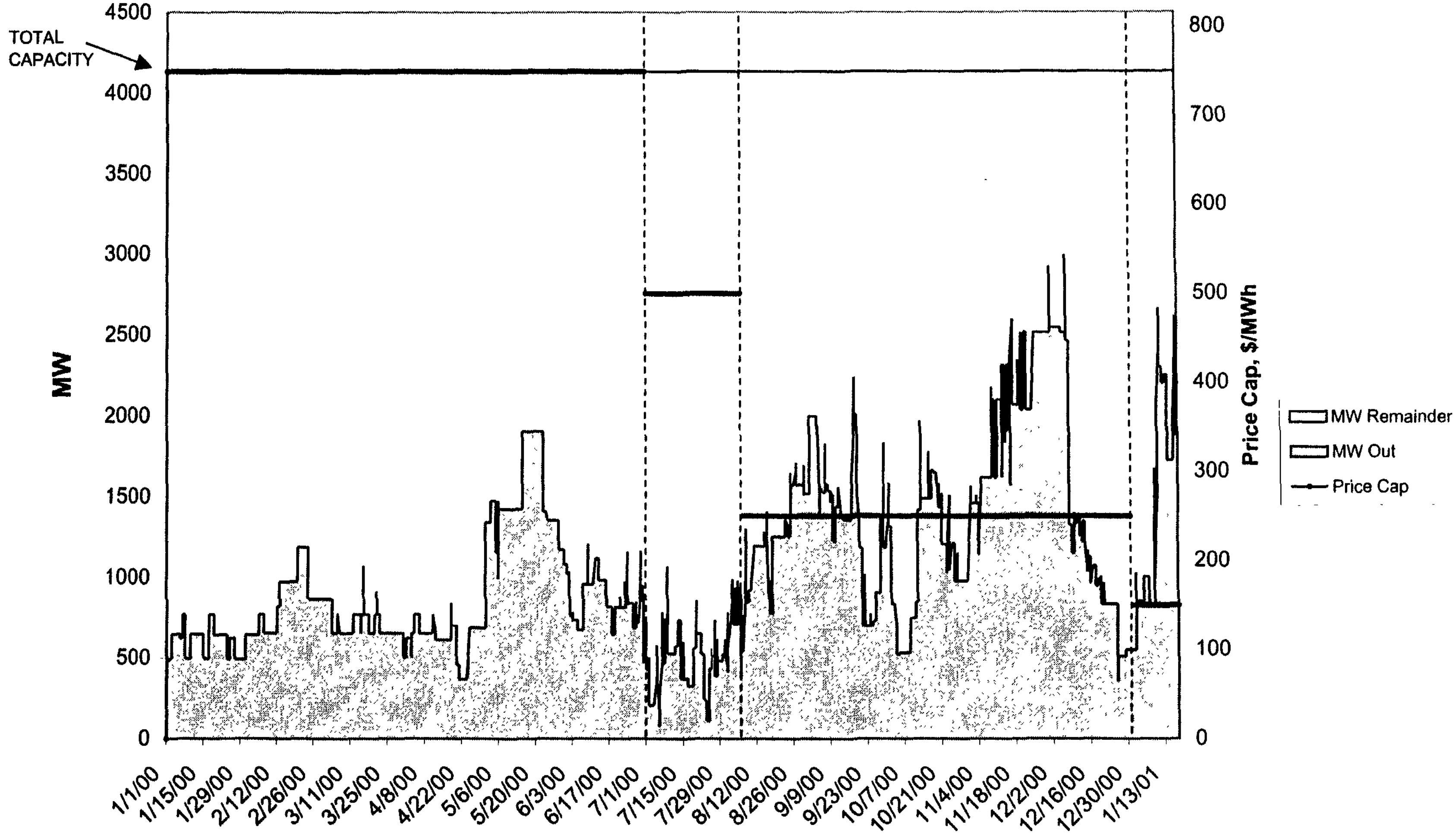
Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Big-Five Units
January 18, 2001 - June 20, 2001



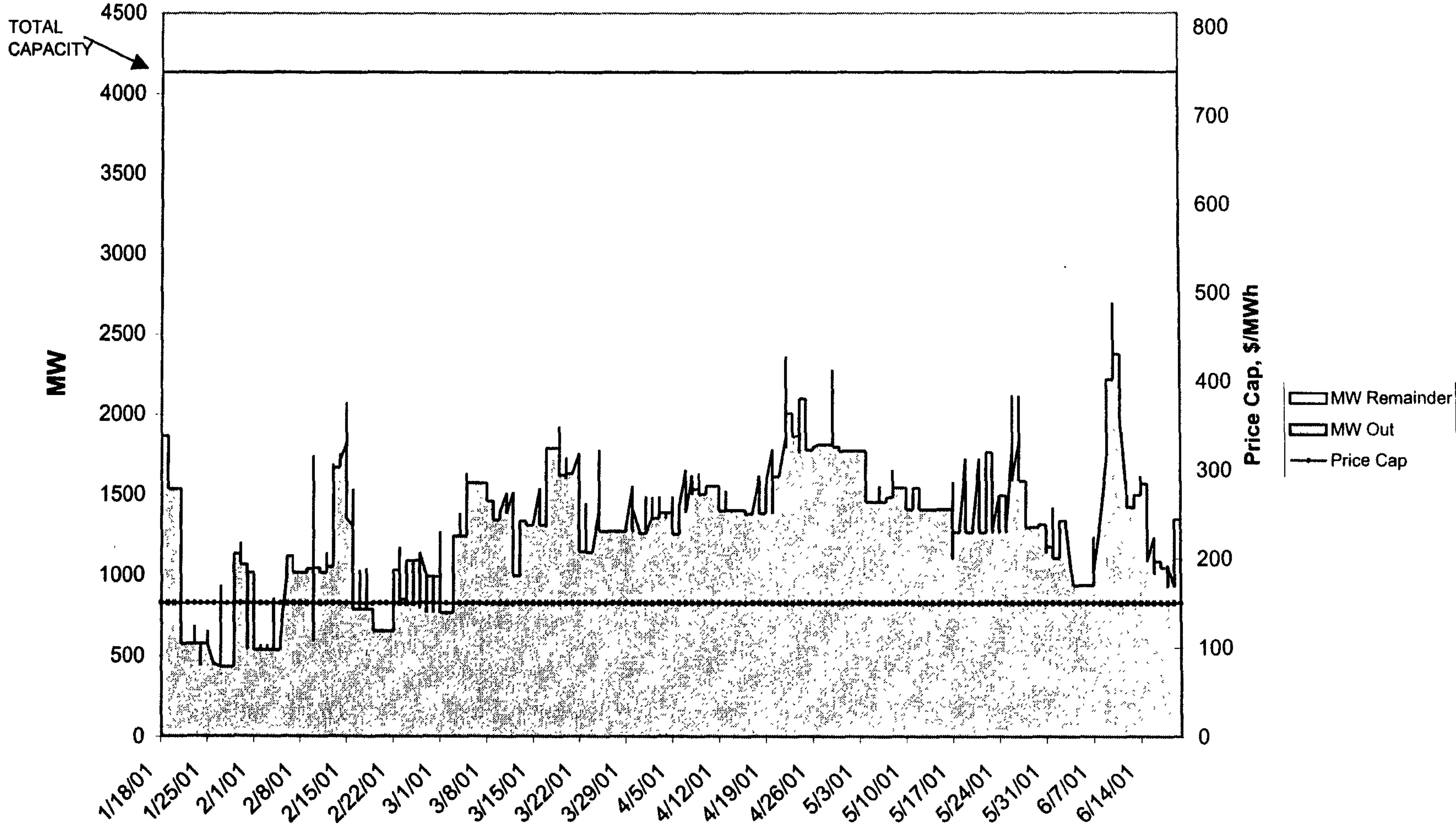
Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all AES Units
January 2000 - January 18, 2001



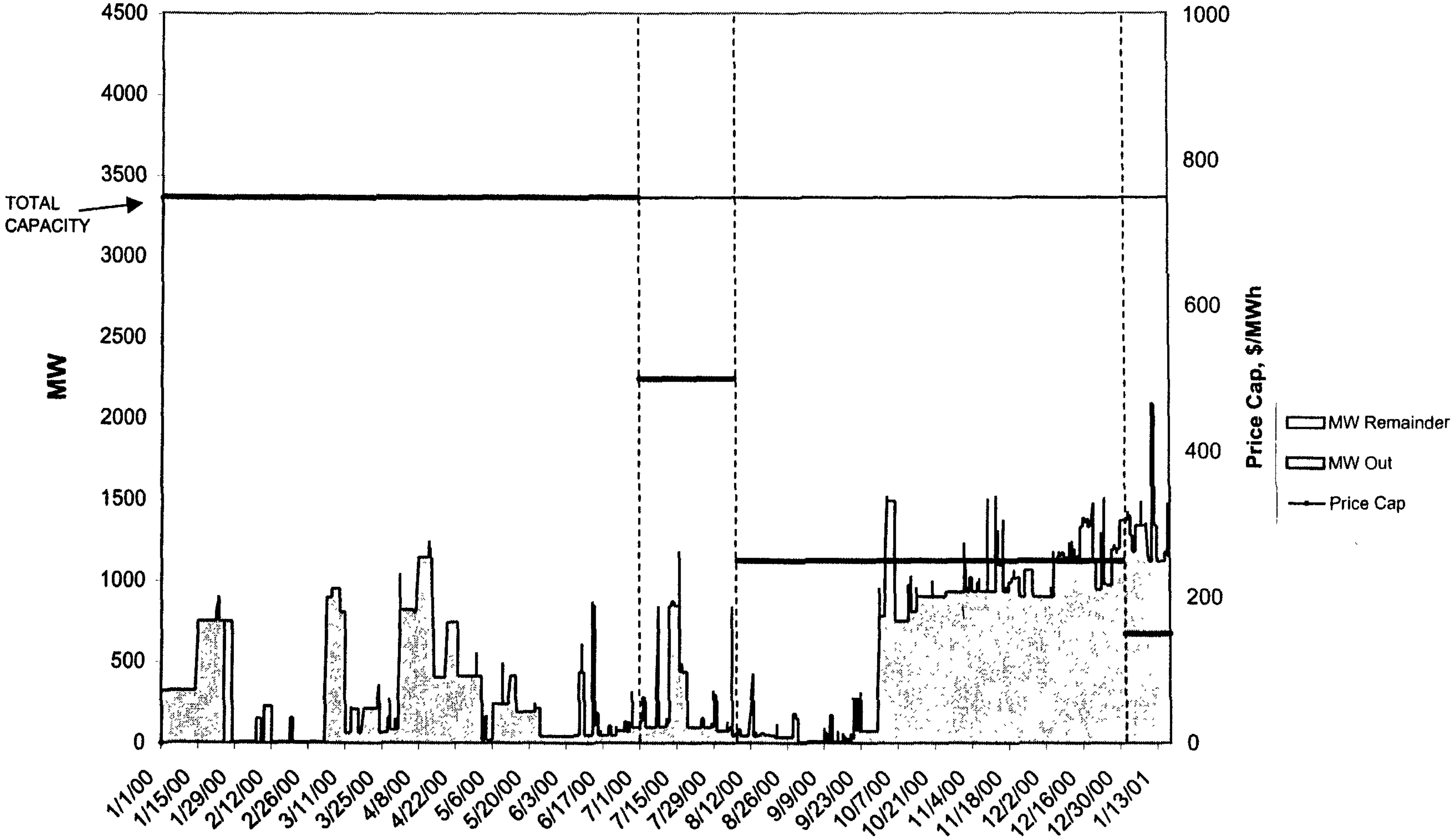
Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all AES Units
January 18, 2001 - June 20, 2001

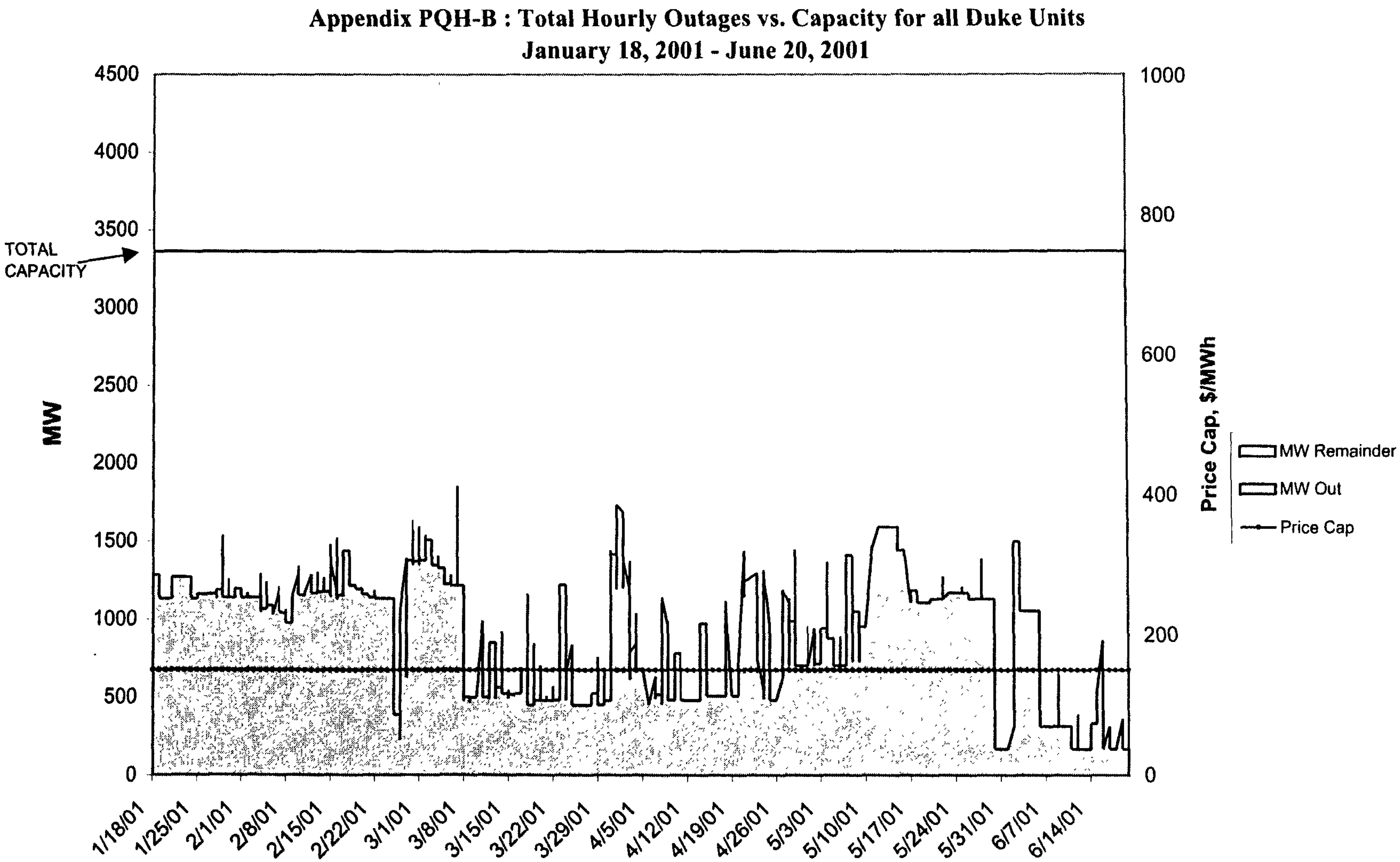


Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Duke Units
January 2000 - January 18, 2001

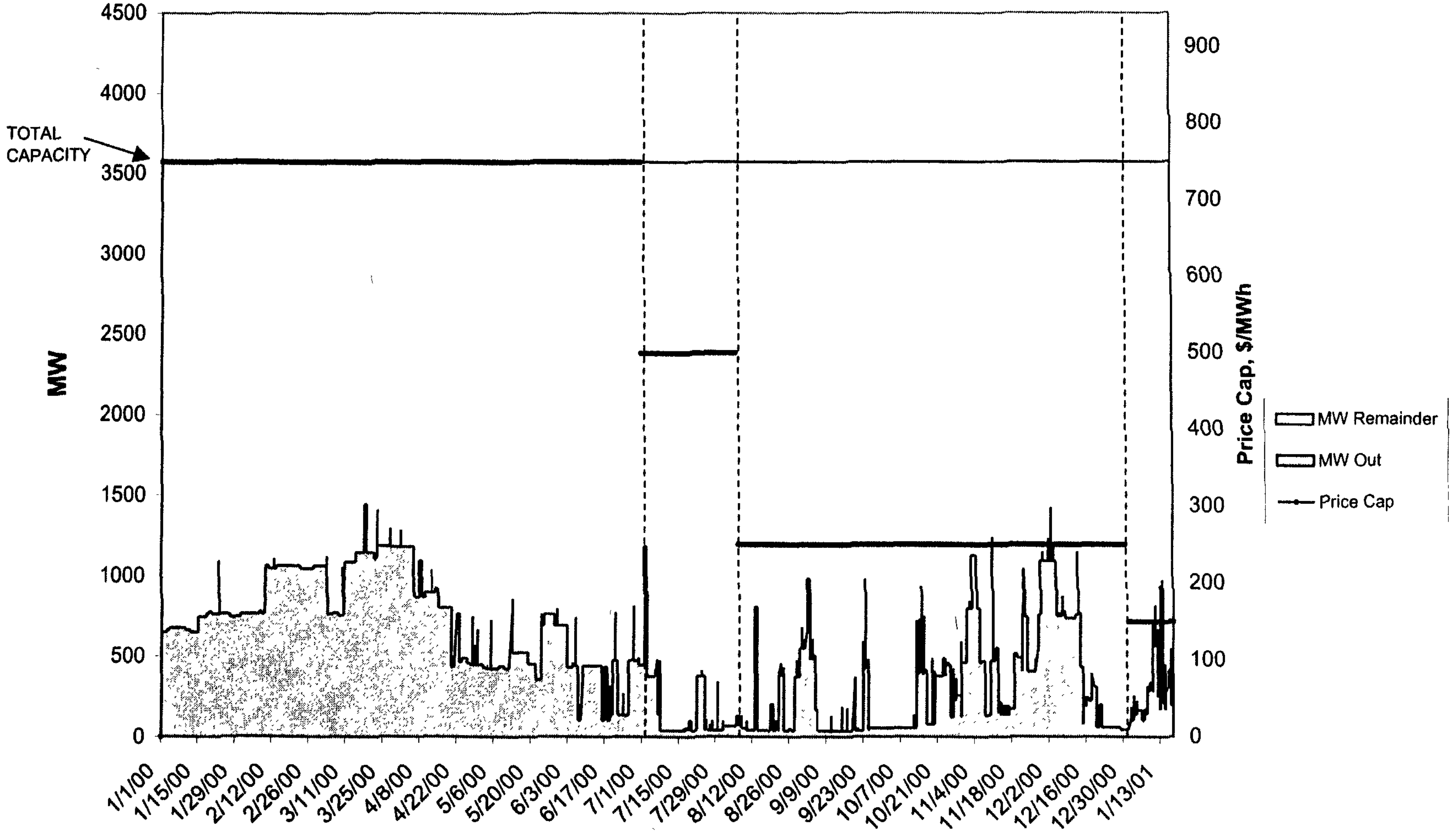


Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.



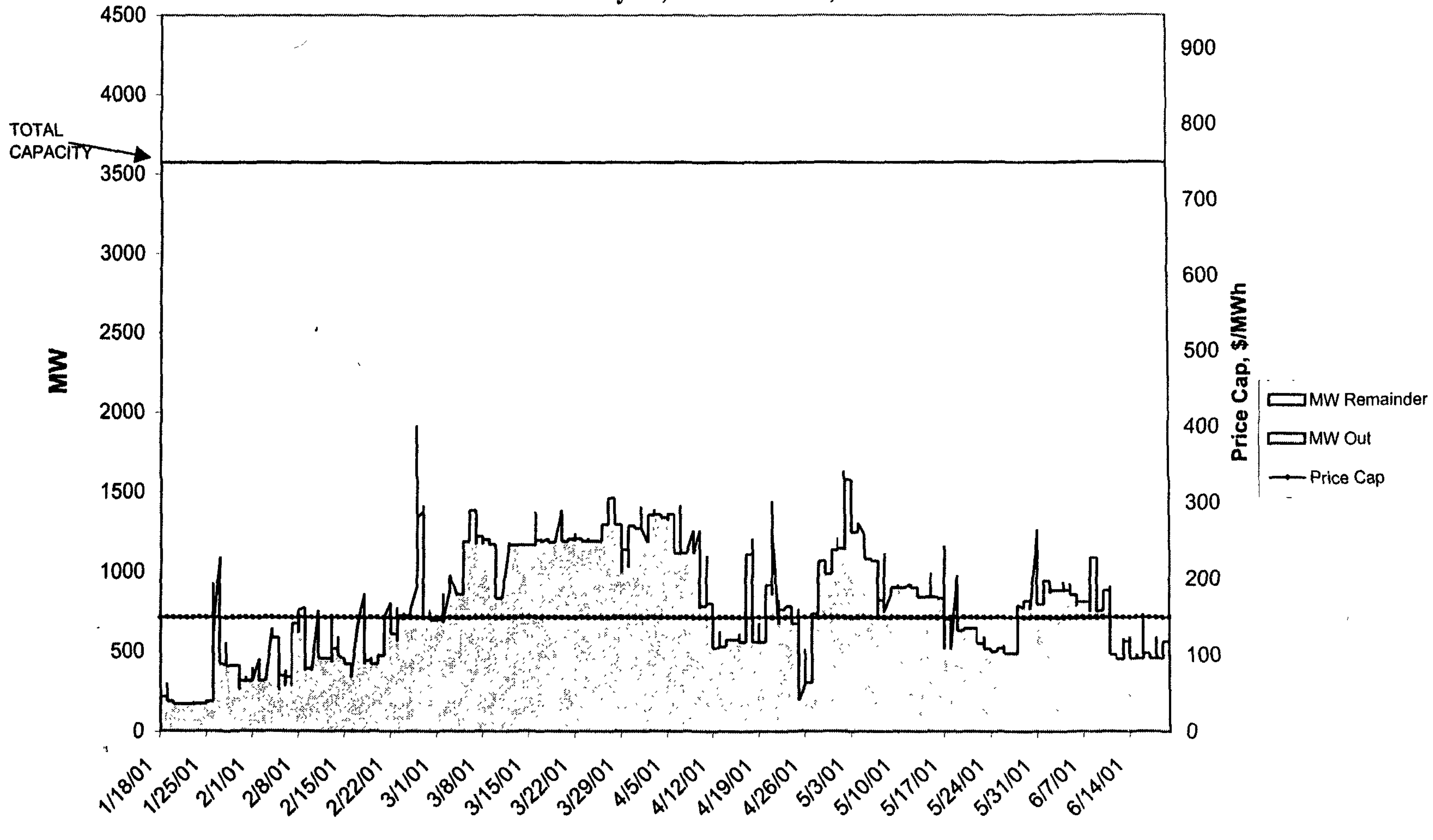
Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Dynegy Units
January 2000 - January 18, 2001



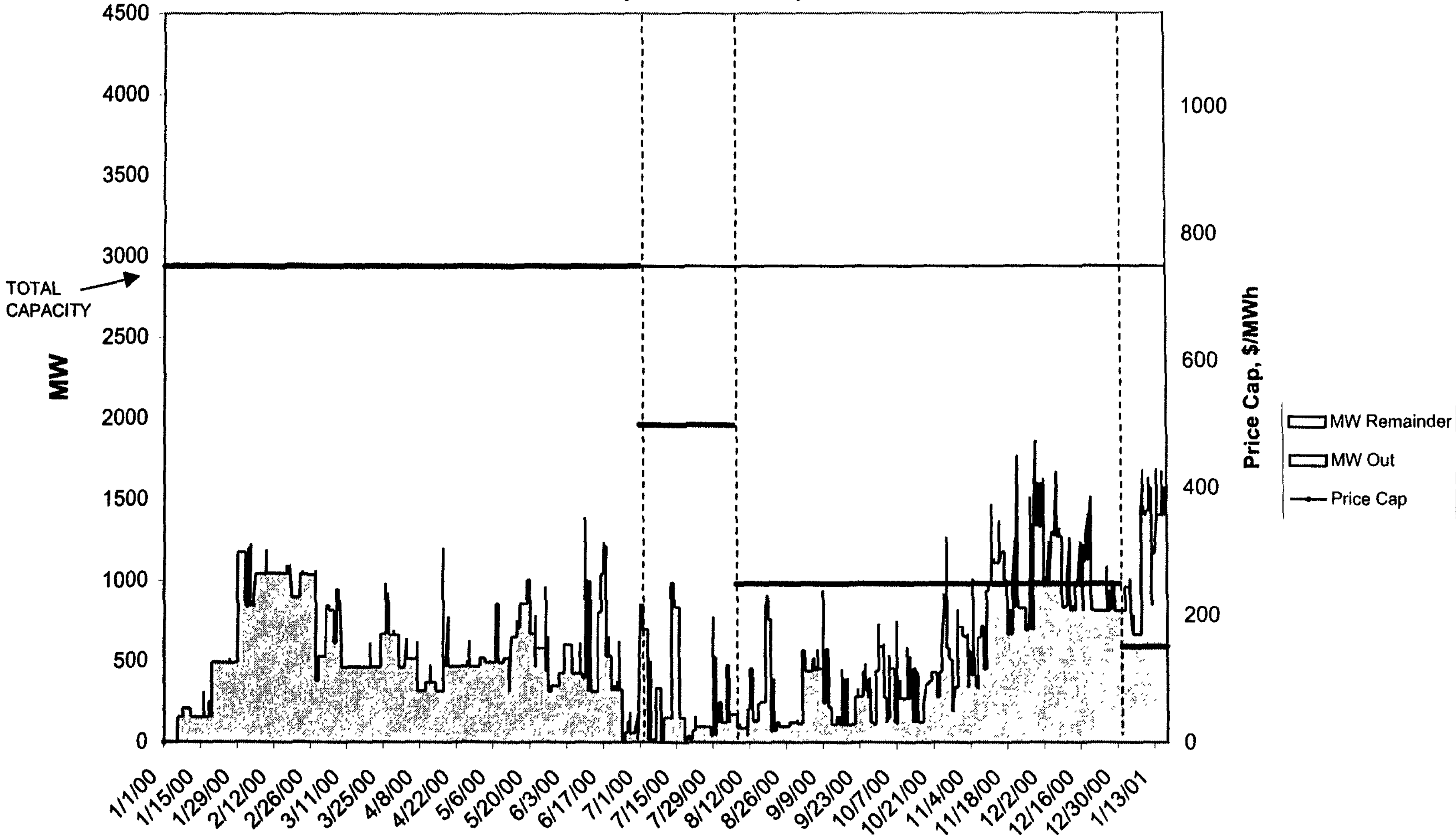
Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Dynegy Units
January 18, 2001 - June 20, 2001



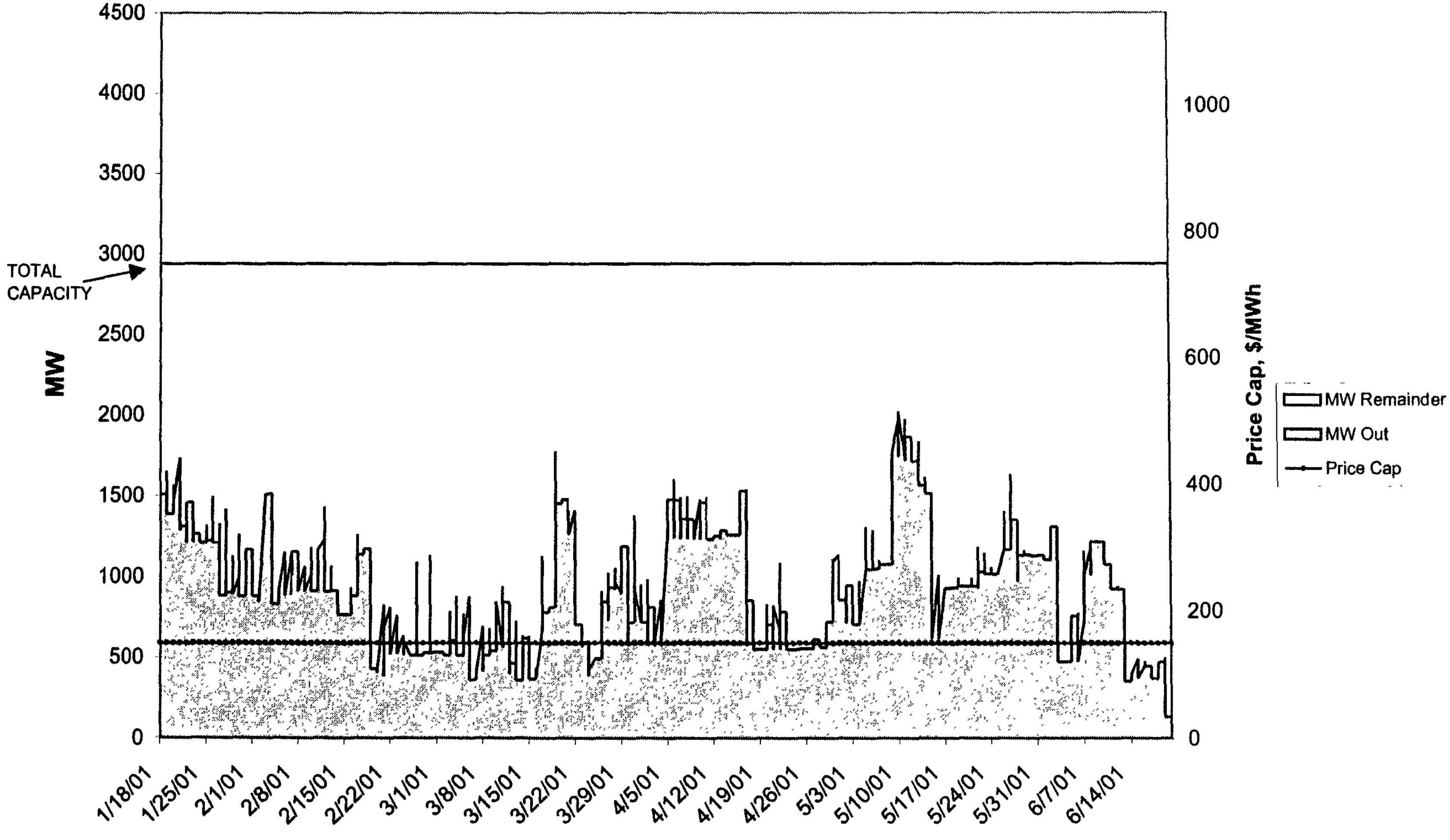
Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Mirant Units
January 2000 - January 18, 2001



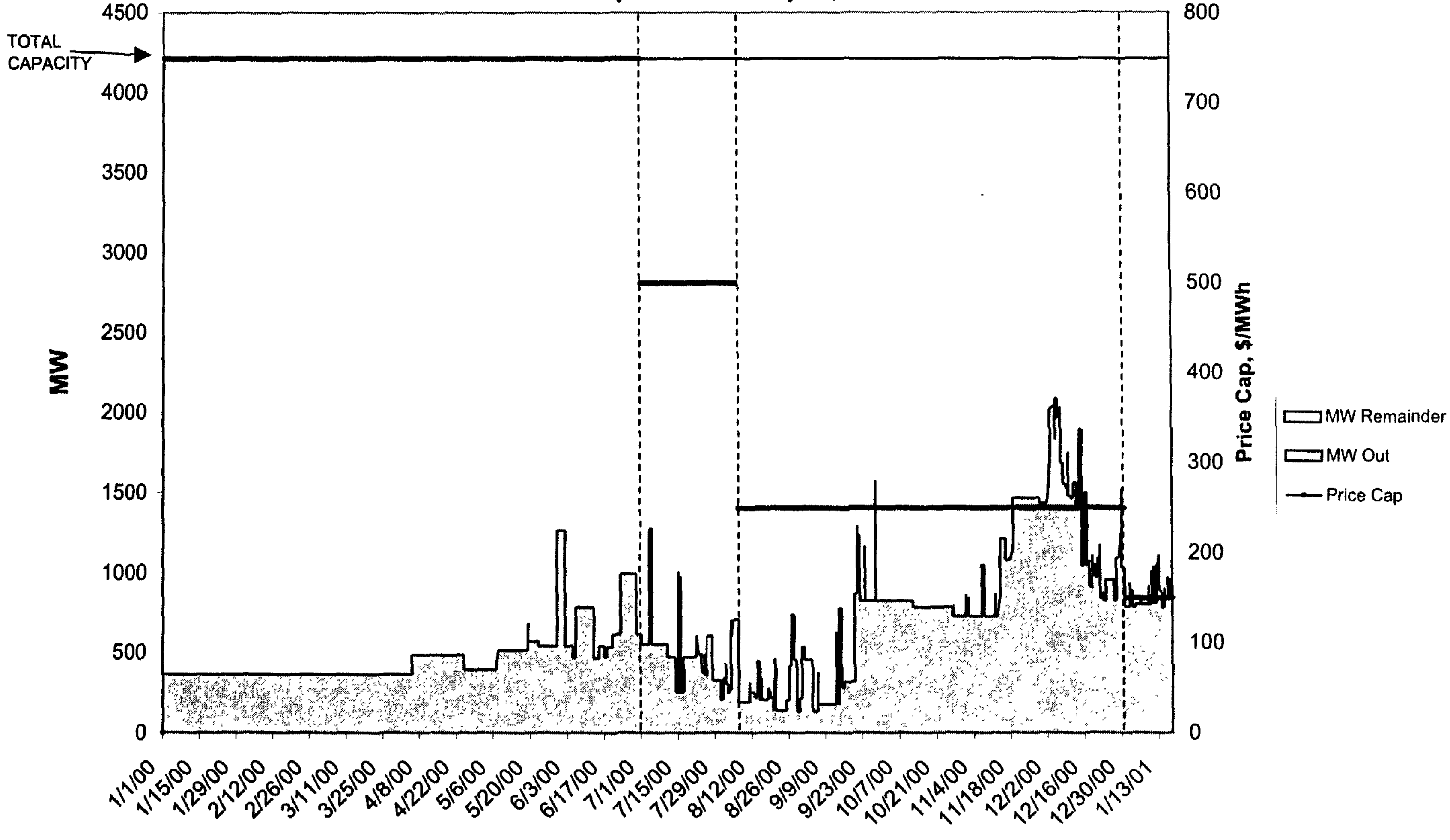
Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Mirant Units
January 18, 2001 - June 20, 2001



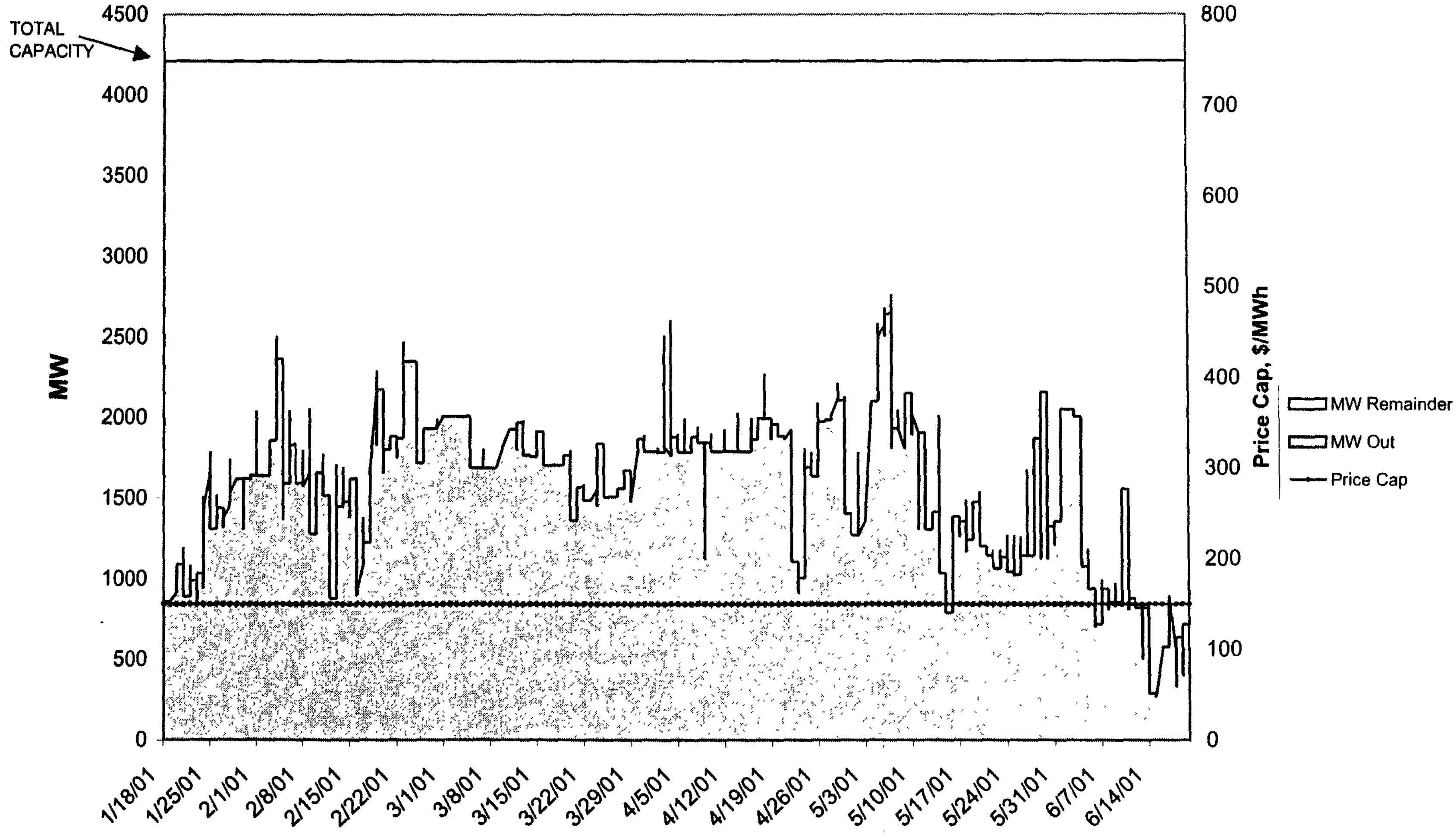
Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Reliant Units
January 2000 - January 18, 2001



Sources: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

Appendix PQH-B : Total Hourly Outages vs. Capacity for all Reliant Units
January 18, 2001 - June 20, 2001



S urces: Capacity from the Capacity Worksheet in Appendix PQH-H.
MW_Out from the CAISO SLIC logs (gen_abail_tbl). Conversion of event-based data to hourly data explained in Appendix PQH-G.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		4/3/00 - 4/6/00
Unit		Redondo 6 (AES/Williams)
Summary of ISO outage databases	[1]	Complete forced outage due to boiler tube leak between 4/3/00 @8:28 PM and 4/6/00 @9:19 AM. (Note that the Availability Table does not have entry for the end of the event)
Text in OutageTable	[2]	Unit Out of Service - Boiler Tube Leak 4/3/2000 8:28 PM 4/6/2000 9:19 AM
Availability Log Information	[3]	Outage key: 523475 4/3/2000 8:28 PM (0 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	A complete outage between 4/3/2000 10:00 PM and 4/6/2000 7:00 AM due to boiler tube failure.
Text in GADS (if outage reported)	[5]	Boiler Tube Failure
Summary of CO Log	[6]	*The Control Operators log reflects that Redondo personnel planned this shutdown, the unit did not trip off.* The log entry of 19:48 hrs on 4/3 reads "Bring Unit 6 down and off" (Alvarez, Nelson, McKnight). There is no mention of a boiler tube leak. *(Note: Mr McKnight consistently keeps detailed logs).* The midnight log indicates the unit status as OUTAGE *(emphasis added)* although no log entries reflect any report to WESCO of problems. The log does reflect tube repairs two days later. Unit online on 4/6/00 @ 07:05.
RMR Unit?	[7]	Yes
Generation during the period?	[8]	Between 4/3/2000 8:28 PM and 4/6/2000 9:19 AM, there was average metered generation of 22.64 MW during 4 hours of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	Between 4/3/2000 8:28 PM and 4/6/2000 9:19 AM: The average bid in the BEEP Stack was 134 MW. Bidding took place during 8 hours. The average bid in HA Operating Reserve markets was 150 MW. Bidding took place during 6 hours.
System Conditions	[10]	No ISO emergencies declared.
Observations		
Likely Overall Conclusions		Although the SLIC and GADS records are not conflicting, the Control Operator Log suggests that the outage due to boiler tube leak was not real.

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : AES outage data received in CD CAL-AES 01293 from the 5_9_01 FERC Request.
[6] : AES CD 6, AES-R012777-R012780.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		8/15/00
Unit		Alamitos 7 (AES/Williams)
Summary of ISO outage databases	[1]	Forced outage for 10 hours on 8/15/00 from 1:50 PM to 11:59 PM. Unit curtailed 134 MW due to Nox limits.
Text in OutageTable	[2]	Alamitos #7 O/S - Curtailed 134 MW - NOx Limits Unit not available due to Nox limits 08/16/00 @0800: WESC reports that due to the cost of NOx requirements, it is not cost effective to run this unit at the present cap of S250/MW. They said they would possibly run the unit if the price cap was substantially higher or lifted. WESC reports Unit Available. 08/30/00 @ 0900 WESC Henry reports Alamitos #7 has been available and bids have are submitted. The unit will be run discretionarily due to emissions credits running short. Unit is curtailed 44MW due to engine trouble.
Availability Log Information	[3]	Outage key: 534064 8/15/2000 1:50 PM (0 MW) 8/15/2000 11:59 PM (90 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	Derated to 90 MW between 7/30/00 11:59 PM and 9/8/00 1.00 PM due to problems in #4 engine pair. Forced outage on 8/5/00 between 3:00 PM and 5:00 PM due to #3 expander vibration.
Text in GADS (if outage reported)	[5]	#4 engine pair #3 expander vibration
Summary of CO Log	[6]	8/15/00 1:26 PM WESCO requested unit on line. The unit was on and loading at 1331 and the unit was shutdown and off line at 1415 at the request of WESCO.
RMR Unit?	[7]	No
Generation during the period?	[8]	During the overlap of ISO Stage 1 emergencies and the outage, there was averaged metered generation of 27.09 MW during 2 hours of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage: The average bid in the BEEP Stack was 74 MW. Bidding took place during 6 hours. The average bid in HA Operating Reserve markets was 91 MW. Bidding took place during 7 hours.
System Conditions	[10]	An ISO Stage 1 emergency was declared on 8/15/00 1100-2000. An ISO Stage 2 emergency was declared on 8/15/00 1300-1930.
Observations		The unit was declared to be on forced outage due to high cost of NOx during a Stage 2 emergency day.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : AES outage data received in CD CAL-AES 01293 from the 5_9_01 FERC Request.
[6] : AES-A008033 - AES-A008043.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		8/30/00 - 9/3/00
Unit		El Segundo 1 (Dynegy)
Summary of ISO outage databases	[1]	175 MW scheduled outage between 8/30/00 @9:16 PM - 9/3/00 @4:00 PM to repair generator brush rigging. The outage was scheduled on 8/31 (late)
Text in OutageTable	[2]	#1 Unit O/S-Gen Brush Rigging Repair generator brush rigging. Return time duration of outage.
Availability Log Information	[3]	Outage Key 535382: 8/30/2000 9:16 PM (0 MW) 9/3/2000 4:00 PM (175 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	20 MW forced outage between 8/11 12:00 AM - 9/1/00 12:00 AM. Unit on reserve shutdown between 8/30/00 @9:16 PM and 9/13/00 @3:40 AM.
Text in GADS (if outage reported)	[5]	For the outage period: prevent creep damage to IP rotor
Summary of CO Log	[6]	"8/15/00 10:25 Irwin electricians clear of brush rigging routines on 1&2. Grnd detectors on. Unit 1 main gen East side changed 3 severely damaged brushes due to vibration. Unit 1 main exciter changed 2 brushes. No changes on unit 2. Monitor unit 1 main generator brushes frequently." 8/30/00 @ 1:28 PM, "Dynegy requests unit 1 and 2 off", "not required ... due to low prices". Unit 1 is tripped on the same day @ 9:16 PM. *Unit 1 was disabled during the shut down with clearances issued on Waterside, Turbine/Generator. Station maintenance cleaned condensers during this time frame. Not much detail as to work being performed on brush rigging other than commentators being ground.*
RMR Unit?	[7]	No
Generation during the period?	[8]	Between 8/30/2000 9:16 PM and 9/3/2000 4:00 PM, there was metered generation of 4.28 MW during 1 hour of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	Between 8/30/2000 9:16 PM and 9/3/2000 4:00 PM: The bid in the BEEP Stack was 150 MW. Bidding took place during 1 hour. The average bid in HA Operating Reserve markets was 85 MW. Bidding took place during 2 hours.
System Conditions	[10]	No ISO emergencies declared.
Observations		The unit was on reserve shutdown "due to low prices" when a complete scheduled outage was declared to CAISO. Moreover, CO logs indicate that the brush rigging routines on Unit 1 were performed on 8/15.
Likely Overall Conclusions		Possible false reporting on the size and type of the outage.

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS event data received in response to CA-DYN - 1 -7 from CD dated 1/21/03; Docket No. EL00 - 95-069, et al.
: Reserve Shutdown event data received as Dynegy's Fourth Response to the First Set of Data Requests CAL - DYN -38.
[6] : DYN AG 155440 - DYN AG 155483.
. Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		10/20/00 - 10/22/00
Unit		Pittsburg 1 (Mirant)
Summary of ISO outage databases	[1]	Complete forced outage between 10/18/2000 @12:32 AM and 10/22/2000 @10:15 PM due to tube leak.
Text in OutageTable	[2]	Unit O/S - Tube Leak Pittsburg Unit 1 ramping down and off-line due to external tube leak. No ETR at this time. 10/18/00 2340: ETR extended to 10/22. SCEM/Pasquito
Availability Log Information	[3]	Outage key: 539698 10/18/2000 12:32 AM (0 MW) 10/22/2000 10:15 PM (150 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	Derated 150 MW between 10/18/2000 1:05 AM and 10/20/2000 5:35 PM due to tube leak. Unit on Reserve shutdown from 10/20/2000 5:35 PM through 10/22/2000 10:15 PM.
Text in GADS (if outage reported)	[5]	BLR FURN WALL TUBE LEAK EXTERNAL TUBE LEAK
Summary of CO Log	[6]	"10/20/2000 5:35 PM: Reported OFM off #1 Unit Blr. tube leak repair to Todd @ SCEM, lifting 150 NMW curtailment." "10/20/2000 7:30 PM: Completed making #1 Boiler available, RT22550 released" "10/22/2000 7:45 AM: Per Todd @ SCEM have #1 Unit in service and available for loading by 2400 tonight." "10/22/2000 8:00 AM: Plugged 2 leaks in north half of #1 unit condenser and closed doors." "10/22/2000 10:15 PM: Paralleled #1 Unit to system, ntfd. Shean @ SCEM of same." *The log reflects the following:* *Tube leak repairs were completed and the unit was released as of 7:30 pm on 10/20/00. The log clearly indicates those responsible for scheduling the unit were notified of the unit's availability at that time. The station continued other "routine" repairs such as condenser tube leak investigations and repairs, however, there is no evidence in the logs to suggest the unit could not be started up upon request That request was made top the station on 10/22/00 at 7.45 am when the unit was requested to be started, on-line, and available for loading as of midnight that night (10/22/00).*
RMR Unit?	[7]	Yes
Generation during the period?	[8]	Between 10/20/2000 5:35 PM and 10/22/2000 10:15 PM, there was metered generation of 10.98 MW during 1 hour of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	Between 10/20/2000 5:35 PM and 10/22/2000 10:15 PM: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	No ISO emergencies declared.
Observations		The GADS records and control operator logs indicate that the unit was available and on reserve shutdown after 10/20/00 7:30 PM. However, SLIC records indicate the outage continued until 10/22/00 10:15 PM.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS event data received on 2/3/03 in response to CAL-MIR-58 in CD 1278.
[6] : Response to Data Request CAL-MIR-58, CD (MIR_E4).
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		11/14/00 - 11/16/00
Unit		Etiwanda 1 (Reliant)
Summary of ISO outage databases	[1]	The unit had a complete forced outage between 11/14/2000 @12:01 AM and 11/16/2000 @6.03 AM due to "Unit cooling tower out of service - 60 hour start delay".
Text in OutageTable	[2]	Unit cooling tower out of service - 60 hour start delay.
Availability Log Information	[3]	Outage Key 541946 11/14/2000 12:01 AM (0 MW) 11/16/2000 6:03 AM (134.7 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	No outage reported, but the unit was on reserve shutdown between 11/3/2000 @11:48 AM and 11/16/2000 2:00 AM.
Text in GADS (if outage reported)	[5]	None
Summary of Shift Supervisor Log	[6]	The unit was listed as "off not required" until 11/14/00. 11/13/00: "1520 #1 East Cooling Tower cleared to continue gutting (to accomodate Unit 2 Start-up) But the unit was ordered to start-up on 11/14/00 @2:07 AM, and the start-up aborted at 5:55 PM due to environmental concern with cooling towers. The log at 5:55 PM reads: "UNIT #1 START UP ABORTED – ENVIRONMENTAL CONCERN WITH UNIT #1 EAST COOLING TOWER CLEARED AND THREE CIRC. WATER PUMPS IN SERVICE . UNIT #1 EAST CT CLEARANCE WILL BE RELEASED ON 11/15/00 AND UNIT AVAILABLE FOR START UP - ROBERT." Unit still marked "off not required" on 11/15/00, Unit goes online 11/16/00 @ 0200. *It appears Etiwanda 1 was off not required while the ISO experienced various Stage Emergencies. Unit was returned to service and released at 1000 hours on 11/16/00.*
RMR Unit?	[7]	Yes
Generation during the period?	[8]	During the overlap of ISO Stage 1 emergencies and the outage, there was metered generation of 0.01 MW during 1 hour of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	ISO Stage 1 emergency on 11/13/00 1658-2046; 11/14/00 1600- 2200; 11/15/00 0700-2300; 11/16/00 1600-2200. ISO Stage 2 emergency on 11/13/00 1713-2048; 11/14/00 1700-1900; 11/15/00 1600-2000.
Observations		An outage declared to ISO although the unit was on reserve shutdown according to company's own records. Moreover, the unit was "off-not required" during a period with Stage 2 emergencies.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS Event Data (Report 97). Received in response to CA -REL -1-35.
[6] : Response to Data Request 36, CAL-REL 749,992.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		11/20/00 - 11/22/00
Unit		Oakland 1 (Duke)
Summary of ISO outage databases	[1]	Complete forced outage between 11/19/00 @6:37 AM and 11/22/00 @12:00 PM due to lube oil cooler and cooling fan needing repair. Unit was also reported to have a forced outage between 10:15 AM and 3:10 PM on 11/20 due to low fuel. Although the initial ETR was 11/21, the ETR was extended to 11/27 by Duke. But Duke reported on 11/27 that the unit was back to service on 11/22.
Text in OutageTable	[2]	Unit unavailable, 0 MW Unit was declared unavailable due to lube oil cooler and cooling fan needing repair. 11/21/00, 2126: New ETR of 11/27/00. RRR/Davis 11/27/00 1938: DETM(Tyler) reports unit was available for 57.7 MW since 11/22/00 1200 hours.-JM. Unit is also unavailable due to low fuel.
Availability Log Information	[3]	Outage key: 542394 11/19/00 6:37 AM (0 MW) 11/22/2000 12:00 PM (57.7 MW) Outage key: 542453 11/20/00 10:15 AM (0 MW) 11/20/00 3:10 PM (0 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	Forced outage with 55 MW curtailment between 11/18/00 @12:34 PM and 11/20/00 @9:09 PM due to problems in cooling air fan and lube oil cooler.
Text in GADS (if outage reported)	[5]	K-1A loss of cooling air fan and generator lube oil cooler work. COOLING AND SEAL AIR SYSTEM
Summary of CO Log	[6]	The CO log states on 11/20 @10:23 PM "Unit K1 A&B Available Full Load and reported same to CO". *Further review warranted concerning this outage. Information within log books does not support shutting down units due to low fuel. Log entry to secure units was made at 1000 hours, but electronic time stamp of log indicate the entry was made at 1500 hour. This was after the delivery of 5136 barrels of fuel.* *Detail lacking within log as the repairs made to the Cooling and Seal Air System, which was logged as primary reason for outage.*
RMR Unit?	[7]	Yes
Generation during the period?	[8]	No generation. Condition 2 RMR unit.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	No bids. Condition 2 RMR unit.
System Conditions	[10]	ISO Stage 1 emergency on 11/19/00 0915-2200, 11/20/00 0520-2100. ISO Stage 2 emergency on 11/20/00 1645-1900.
Observations		GADS data and CO log indicate the unit was available as of 11/20 @ 10:23 PM, but the SLIC records show that the unit came back from outage on 11/22 @ 12:00 AM.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS event data received in response to CAL-DUKE-58 and CAL-DUKE-163 on 1/29/03.
[6] : Response to Data Requests CAL-DUK-58 and CAL-DUK-163, CD number 27, received on 1/30/03.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		12/19/00 - 12/20/00
Unit		Redondo 5 (AES/Williams)
Summary of ISO outage databases	[1]	Unit on forced outage between 12/19/2000 7:18 PM and 12/20/2000 6:43 PM due to a boiler tube leak.
Text in OutageTable	[2]	Unit O/S - Boiler Tube leak Unit coming off line. No ETR 1918: Unit OFF line. No ETR at this time 12/20/00 1148: WESC reports unit may be available to begin start-up by 2000 hours tonight, if test today reveal no problems. WESC will keep ISO informed of pending status.
Availability Log Information	[3]	Outage key: 544780 12/19/2000 7:18 PM (0 MW) 12/20/2000 6:43 PM (175 MW) 12/21/2000 7:55 AM (40 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	Unit on forced outage between 12/19/00 8:00 PM and 12/20/2000 8:00 PM due to boiler tube problems. 12/20/00 8:00 PM to 12/29/00 12:00 PM unit derated 55 MW due to weak boiler tubes.
Text in GADS (if outage reported)	[5]	Boiler Tube Leak Weak Boiler Tubes
Summary of CO Log	[6]	The Control Operators log reflects that Redondo reported to WESCO a suspected boiler tube leak on 12/19/00 at 0455 hrs. At 1837 hrs that day, WESCO requested Unit 5 off at 1900 hrs (Jim). Personnel on shift are Dixon, Saeed and Jackson. At 1918 hrs the log reads: Unit 5 is off line. "Blr. tube leak". *Note: It is not typical to see quotes in the log in this manner unless a statement is deliberately attributed to others.* On 12/20 at 1745 hrs the boiler is filled and no leaks are found. The unit is released to WESCO and WESCO requests it be started.
RMR Unit?	[7]	Yes
Generation during the period?	[8]	During the overlap of ISO Stage 1 emergencies and the outage, there was metered generation of 6.37 MW during 1 hour of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage: The bid in the BEEP Stack was 20 MW. Bidding took place during 1 hour. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	ISO Stage 1 emergencies on 12/19/00 0130-2400 and 12/20/00 0915-2400. ISO Stage 2 emergencies on 12/19/00 0915-2400 and 12/20/00 1410-2400.
Observations		The forced outage declared to the CAISO appears in GADS records too. The outage took place because of suspected boiler tube leaks. However, control operator log entries raise suspicions that the outage was not real. There were no leaks found.
Likely Overall Conclusions		Entries in the control operator logs suggest that the outage was not necessary.

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : AES outage data received in CD CAL-AES 01293 from the 5_9_01 FERC Request.
[6] : AES CD 6, AES-R013282-R013283.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

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Period		12/28/00 - 12/30/00
Unit		Etiwanda 1 (Reliant)
Summary of ISO outage databases	[1]	Complete forced outage between 12/28/2000 @8:59 AM and 12/30/2000 @12:30 PM due to "cooling water tower work".
Text in OutageTable	[2]	Etiwanda #1 O/S Etiwanda #1 unavailable due to forced cooling water tower work. ETR: 12/30/00 @ 1200
Availability Log Information	[3]	Outage Key: 545116 12/28/2000 8:59 AM (0 MW) 12/30/2000 12:30 PM (134.7MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	No outage reported.
Text in GADS (if outage reported)	[5]	None
Summary of Shift Supervisor Log	[6]	*Further review warranted concerning this outage. Forced outage attributed to Cooling Water Tower work. Shift Supervisors logs indicate temporary repairs to the cooling water tower were completed on 12/26/00 at 1645 hours. Etiwanda Unit 1 was released to NORAM at 0520 on 12/27/00 At 0525 NORAM reported that Unit 1 was not required for load at this time. Shift Supervisors log on 12/28/00 at 0000 hours indicated Unit 1 is in standby mode. On 12/28/00 REI requests ISO approval to repair 2E Cooling Tower Riser.*
RMR Unit?	[7]	Yes
Generation during the period?	[8]	Between 12/28/2000 8:59 AM and 12/30/2000 12:30 PM, there was no metered generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	Between 12/28/2000 8:59 AM and 12/30/2000 12:30 PM: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	No ISO emergencies declared.
Observations		The GADS records and Shift Supervisor logs do not mention any outage during the period, but SLIC records show a forced outage.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS Event Data (Report 97). Received in response to CA -REL -1-35.
[6] : Response to Data Request 36, CAL-REL 749,992.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

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Period		12/28/00 - 12/30/00
Unit		Etiwanda 2 (Reliant)
Summary of ISO outage databases	[1]	Complete forced outage between 12/28/2000 @9:03 AM and 12/30/2000 @12:30 PM due to "cooling water tower work".
Text in OutageTable	[2]	Etiwanda #2 O/S Etiwanda #2 unavailable due to forced cooling water tower work. ETR: 12/30/00 @ 1200
Availability Log Information	[3]	Outage Key: 545117 12/28/2000 9:03 AM (0 MW) 12/30/2000 12:30 PM (133.9 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	No outage reported.
Text in GADS (if outage reported)	[5]	None
Summary of Shift Supervisor Log	[6]	*0001 12/28 the unit was taken off line manually by operating personnel at the request of REI.* *0900 12/28 REI reported to the station that the ISO had given approval to repair the Unit 2 East Cooling tower rise which was leaking. These repairs were expected to be completed on Saturday AM (12/30). The work was completed on 12/29 at 1651 hours. Both units 1 and 2 were called to start-up such that they be on and released for loading on 1/2/01 at 5 am.*
RMR Unit?	[7]	Yes
Generation during the period?	[8]	Between 12/28/2000 9:03 AM and 12/30/2000 12:30 PM, there was no metered generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	Between 12/28/2000 9:03 AM and 12/30/2000 12:30 PM: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	No ISO emergencies declared.
Observations		According to the Shift Supervisor logs, the outage ended on 12/29, not on 12/30.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS Event Data (Report 97). Received in response to CA -REL -1-35.
[6] : Response to Data Request 36, CAL-REL 749,992.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		1/26/01 - 1/28/01
Unit		Etiwanda 2 (Reliant)
Summary of ISO outage databases	[1]	Unit on Scheduled outage between 1/25/2001 @4:00 AM and 1/28/2001 @5:15 PM to repair vacuum leak.
Text in OutageTable	[2]	Unit O/S - Turbine Bearing Work Unit out of seervice to repair major vacuum leak on #3 bearing for #2 turbine. Emergency Return: Duration
Availability Log Information	[3]	Outage key: 547369 1/25/2001 4:00 AM (0 MW) 1/28/2001 5:15 PM (133.9 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	Maintenance Outage between 1/25/2001 4:30 AM and 1/26/2001 8:35 PM due to vacuum leak. Unit on Reserve shutdown from 1/26/2001 8:35 PM through 1/28/2001 3:02 PM.
Text in GADS (if outage reported)	[5]	Loss of vacuum not attributable to a particular component such as air ejectors or valves; or, high back pressure not attributable to high circulating water temperature, or vacuum losses from a known cause. Vacuum Leak - #3 Turb Brg Drain
Summary of Shift Supervisor Log	[6]	1/25/01: "0257 APPROVAL TO TAKE UNIT #2 DOWN AND OFF LINE – 4 DAYS OUTAGE." "0312 REI REQUEST UNIT #2 SHUT DOWN ABORTED – ISO SCHEDULED 120 MWS ETGS UNIT #2 HRS 0600, AND 0700. WILL CALL AFTER CONTACTING KEVIN - MATT." "0337 REI APPROVAL TO REMOVE UNIT #2 FROM SERVICE FOR 4 DAYS OUTAGE" "0430 UNIT #2 OFF LINE VIA PB." The unit was "Off Line Not Needed" according to the nightshift entry on 1/26/01. 1/26/01: "2035 Released Unit #2 to reliant." 1/28/01: "0405 Go into Startup on Unit #2 to be on ASAP." "1502 UNIT #2 ON LINE." *Unit outage is suspicious in nature. No mention of vacuum problem on Unit 2 in Shift Supervisors midnight log data on 12/25/01. At 0337 on 12/25/01 REI approves removing Unit 2 from service for a four day outage. Log entries report "unit down not needed" At 2035 hours on 1/26/01 control room released Unit 2 to REI. At 0405 on 01/28/01 the log reads "Go into startup on Unit #2 to be on ASAP". Unit was on line at1502 hours. Unit could have been called into service much sooner to assist ISO with various Stage Emergencies.*
RMR Unit?	[7]	Yes
Generation during the period?	[8]	During the overlap of ISO Stage 1 emergencies and the outage, there was average metered generation of 14.24 MW during 4 hours of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
Market Conditions	[10]	ISO Stage 1, 2, and 3 emergencies on 1/26/01 0001-2359, 1/27/01 0001-2359 and 1/28/01 0001-2359.
Observations		GADS records and CO logs indicate that the outage ended and the unit was available on 1/26/01 at 8:35 PM. But the SLIC shows the outage continued until 1/28/01 at 5:15 PM.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS Event Data (Report 97). Received in response to CA -REL -1-35.
[6] : Response to Data Request 36, CAL-REL 749,992.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		3/20/01 - 3/21/01
Unit		Pittsburg 1 (Mirant)
Summary of ISO outage databases	[1]	Forced outage from 3/8/2001 12 25 PM to 3/21/2001 4 47 PM due to massive boiler tube leak
Text in OutageTable	[2]	Unit O/S - boiler tube leak 03/08/01, 1225 Unit tripped off line due to massive boiler tube leak ETR 2-3 days to ascertain damage and repair 03/10/01, 0833 ETR delayed by two days New ETR is 3/13/01 at 0001 hrs 0132 12 March 2001 Revised ETR, 1800 17 March 2001 KAG 03/12/01 1138 Per Mirant/Chris, new ETR is 3/18/01, due to more tube damage than anticipated TPD 0915 14 March 2001 Revised ETR 1800 21 March 2001 KAG
Availability Log Information	[3]	Outage key 551578 3/8/2001 12.25 PM (0 MW) 3/21/2001 4 47 PM (142 MW)
Text in General Log	[4]	Not available
Summary of GADS info	[5]	Unit on Reserve Shutdown from 3/20/2001 2 15 PM through 3/21/2001 2 35 AM Curtailed 13 MW starting 1/1/2001 (indefinitely) due to combustion control problems Curtailed 8 MW between 2/21/2001 3 22 PM and 3/25/2001 12 42 AM due to Unit 7 being on Start-up bank Curtailed 150 MW between 3/8/2001 12 28 PM and 3/20/2001 2:15 PM due to boiler tube leak
Text in GADS (if outage reported)	[5]	BLR COMB/STEAM CONTROLS Combustion Control Problems SWTCHYRD CIRCUIT BREAKERS ISO Net MW at full load only 142 MW due to #7 Unit on Start-up Bank BLR FURN WALL TUBE LEAK Boiler tube leak (1000 - 1090)
Summary of CO Log	[6]	CO logs On 3/8/01, the unit tripped due to boiler "tube leak in Fire box" "3/20/2001 6 00 00 AM: D Tharp report off #1 boiler RT 23001 " "3/20/2001 2.15 00 PM Reported off #1 Unit clearance to Terecina @ MAEM, #1 Unit on reserve shutdown, but #1 Blr is lite-off for start up (16 Hr Cold Start-up time)" "3/20/2001 4 42.00 PM Per Switch log ACO M/A #1 Unit from Reserve Shutdown" "3/20/2001 8:54:29 PM Requested T O Ccollins Complete yard switching to M/A #1 Unit from fuel economy" "3/20/2001 9 08 04 PM. T.O Collins Completed yard switching to M/A #1 Unit from fuel economy" "3/20/2001 11 00 00 PM #1 UNIT IS LITE OFF, #2 UNIT IS DOWN, #3 & #4 UNIT ARE ON LINE " "3/21/2001 2.35 00 AM #1 UNIT IS PAR. WITH THE SYSTEM " *The logs reflect a massive tube leak in the fire box which extinguished the flames and resulted in the shutdown of the unit This type of result from a tube leak legitimizes the severity of the leak* *The logs reflect completion of tube leak repairs on 3/19/01 at 9 30 am with the unit drained to proper firing level for start-up at 8 27pm that day* *The unit stayed off line until released to MAEM and called upon for start by MAEM on 3/20/01 at 2.15pm* *In the interim period between the completion of the tube repairs and the start of the unit the boiler air preheaters were washed and some condenser tube repairs were done* *It would appear that failure to conduct these maintenance tasks would not have kept the unit from starting if requested*
RMR Unit?	[7]	Yes
Generation during the period?	[8]	During the overlap of ISO Stage 1 emergencies and the outage, there was average metered generation of 88 61 MW during 11 hours of generation
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage The average bid in the BEEP Stack was 22 MW Bidding took place during 2 hours No bidding took place in HA Operating Reserve markets
Market Conditions	[10]	ISO Stage 1 emergencies on 3/20/01 0001-2159 and 3/21/01 0626-2259 ISO Stage 2 emergency on 3/20/01 0001-2159 ISO Stage 3 emergency on 3/20/01 0917-1430
Observations		The unit was ready to generate on 3/21 @2 35 AM according to logs, but the SLIC records show outage ended on 3/21 @ 4 47 PM
Likely Overall Conclusions		The unit was likely held off the market during an emergency day after the unit came back from outage

[1] . CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY
[4] Not available.
[5] · GADS event data received on 2/3/03 in response to CAL-MIR-58 in CD 1278.
[6] Response to Data Request CAL-MIR-58, CD (MIR_E4)
Direct quotes from CO/Shift Supervisor logs are in quotation marks Log summaries are in plain text and opinions are italicized.
[7] Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General
[8] data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files
[9] BEEP Stack data from data request Cal-ISO-1 CAL_ISO_1_Engy_xxxx csv files
Bids in Operating Reserve markets from data request Cal-ISO-4 CAL_ISO_4_Gen_Sch2_xxxx csv files
[10] List of CAISO-declared emergency periods from http.//www caiso.com/docs/09003a6080/08/8a/09003a6080088aa7 xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		4/9/01 - 4/10/01
Unit		Ellwood (Reliant)
Summary of ISO outage databases	[1]	Unit on forced outage between 1/12/2001 5:50 PM and 4/10/2001 6:24 AM due to exciter trouble.
Text in OutageTable	[2]	Goleta/Ellwood jet O/S - Exciter Trouble Exciter trouble 02/14/01, 1105: The generator rotor has been removed and is being machined. Tentative ETR 3/16/01. 04/07/01 @ 0438 NES1/Wilson reports new ETR 04/09/01 @ 2359 04/10/01 @ 0320 NES1/Sticka reports new ETR 04/10/01 @ 2359
Availability Log Information	[3]	Outage key: 546441 1/12/2001 5:50 PM (0 MW) 1/23/2001 2:55 PM (0 MW) 4/10/2001 6:24 AM (56.1)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	Unit on forced outage between 1/12/2001 5:48 PM and 4/9/2001 3:13 PM due to rotor windings. Unit on Reserve shutdown from 4/9/2001 3:35 PM through 5/6/2001 12:01 AM.
Text in GADS (if outage reported)	[5]	Rotor windings Open field on generator
Summary of Shift Supervisor Log	[6]	Not available.
RMR Unit?	[7]	No
Generation during the period?	[8]	During the overlap of ISO Stage 1 emergencies and the outage, there was no metered generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	ISO Stage 1 emergency on 4/9/01 0750-1045. ISO Stage 2 emergency on 4/9/01 0750-1045.
Observations		GADS records indicate that the outage ended on 4/9/01 at 3:13 PM, but Dynegy waited until 4/10/01 at 6:24 AM to notify the CAISO about the end of the outage.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS Event Data (Report 97). Received in response to CA -REL -1-35.
[6] : Not available.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		5/12/01 - 5/14/01
Unit		Etiwanda 1 (Reliant)
Summary of ISO outage databases	[1]	Complete forced outage between 5/9/01 @10:38 PM and 5/14/01 @1:25 PM due to boiler tube leak and unit water wall trouble.
Text in OutageTable	[2]	Unit water wall trouble. ETR 5/31/01. Etiwanda 1 not available - boiler tube leak 05/14/01 0012 NES1 reports the unit is in start up at this time. Once paralleled it will be released for full load.
Availability Log Information	[3]	Outage Key 557928 5/9/2001 1:10 PM (54 MW) 5/14/2001 1:25 PM (79MW) Outage key 558002 5/9/2001 10:38 PM (0 MW) 5/14/2001 1:26 PM (134.7 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	A complete forced outage between 5/9/01 @10:35 PM and 5/12/01 @12:45 AM due to boiler tube leak and water wall trouble. Unit on reserve shutdown between 5/12/01 @12:45 AM and 5/14/01 @1:15 AM.
Text in GADS (if outage reported)	[5]	Between 5/9 and 5/12: Boiler tube Leak Waterwall #28 E>W East side; furnace wall. No outage reported between 5/12 and 5/14.
Summary of Shift Supervisor Log	[6]	Not available.
RMR Unit?	[7]	Yes
Generation during the period?	[8]	Between 5/12/2001 12:45 AM and 5/14/2001 1:15 AM, there was metered generation of 4.92 MW during 1 hour of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	Between 5/12/2001 12:45 AM and 5/14/2001 1:15 AM: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	No ISO emergencies declared.
Observations		
Likely Overall Conclusions		False declaration of forced outage between 5/12 and 5/14 when in fact the unit was on reserve shutdown.

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS Event Data (Report 97). Received in response to CA -REL -1-35.
[6] : Not available.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-C: UNITS REPORTED TO THE CAISO AS UNAVAILABLE DUE TO REQUIRED MAINTENANCE OR OTHER LIMITATIONS, WHERE SELLERS' INTERNAL RECORDS SHOW THAT THE UNIT WAS AVAILABLE

Period		5/30/01 - 5/31/01
Unit		Etiwanda 5 (Reliant)
Summary of ISO outage databases	[1]	Unit on forced outage from 5/30/2001 6:25 PM through 5/31/2001 5:34 AM because operators unable to get turning gear moving.
Text in OutageTable	[2]	unable to get turning gear moving 05/31/01 0110 matt reports the electricians called out to repair this problem unsuccessful. Will wait for others in the morning to look at problem. Possible ETR is noon.
Availability Log Information	[3]	Outage key: 559906 5/30/2001 6:25 PM (0 MW) 5/31/2001 5:34 AM (130 MW) 6/4/2001 2:09 AM (130 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	Unit on Reserve Shutdown from 5/30/2001 5:30 PM through 5/31/2001 9:59 AM. No outage mentioned.
Text in GADS (if outage reported)	[5]	None.
Summary of Shift Supervisor Log	[6]	Not available.
RMR Unit?	[7]	No
Generation during the period?	[8]	During the overlap of ISO Stage 1 emergencies and the outage, there was no metered generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	ISO Stage 1 emergencies on 5/30/01 1130-2359 and 5/31/01 0900-2300. ISO Stage 2 emergency on 5/30/01 1400-2359 and 5/31/01 1132-2215.
Observations		The GADS records show a reserve shutdown during the period when Reliant declared a forced outage to the CAISO.
Likely Overall Conclusions		The unit was likely withheld during emergency periods.

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS event data received on 2/3/03 in response to CAL-MIR-58 in CD 1278.
[6] : Not available.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-D: ANOMALOUS OUTAGE EVENTS

Period		11/18/00 - 12/5/00
Unit		El Segundo 1 and 2 (Dynegy)
Summary of ISO outage databases	[1]	Complete forced outage between 11/19/00 1 05 PM and 12/5/00 5·40 AM for Unit 1, and 11/19/00 1·05 PM and 12/5/00 6 40 AM for Unit 2, due to an inability to staff the plant (staff on vacation).
Text in OutageTable	[2]	Unit O/S - Plant Staffing 11/21/00 LJT Per Mike Stewart, Units 1 and 2 boilers are currently still full of water We are not able to restart these units because we do not have the operator staffing during winter months to start these units safety We have to call on our operators to work overtime to run Units 1 and 2 but because of vacation schedules, we are not able to get the operators to come in. Per G.Larsen, Extend outage to 5/1/01. Notified Gen Desk. El Segundo #1 unavailable due to inability to staff plant. Unit was ordered on 11/19 @ 1211. El Segundo #2 unavailable due to inability to staff plant. Unit was ordered on 11/19 @ 1211
Availability Log Information	[3]	Unit 1 Outage key· 542397 11/19/2000 1:05 PM (0 MW) 11/20/2000 12:42 AM (0 MW) 12/5/2000 5·40 AM (175 MW) Unit 2 Outage key: 542398 11/19/2000 1·05 PM (0 MW) 11/20/2000 12:45 AM (0 MW) 12/5/2000 6 40 AM (164 MW)
Text in General Log	[4]	not available
Summary of GADS info	[5]	Unit 1 on Reserve Shutdown from 11/18/2000 12:06 AM through 12/1/2000 12·00 AM. Unit 2 on Reserve Shutdown from 11/18/2000 12:20 AM through 12/1/2000 12:00 AM
Text in GADS (if outage reported)	[5]	None
Summary of CO Log	[6]	Unit off-line 11/18/00 @ 0600: Units were removed from service. "1800 Nightshift Unit 1 and 2 down not needed" "1850 Unit 1 and 2 Control room de-manned." Unit 1 and 2 return on 12/5/00 @ 0544 and 0624, respectively. *The log reflects that both units were shutdown and remained off line not needed for the entire period. There is NO evidence from the logs that these units could not operate.*
RMR Unit?	[7]	No
Generation during the period?	[8]	Unit 1. During the overlap of ISO Stage 1 emergencies and the outage, there was no metered generation. Unit 2· During the overlap of ISO Stage 1 emergencies and the outage, there was metered generation of 2.09 MW during 1 hour of generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage: Unit 1. No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets. Unit 2: No bidding took place in the BEEP Stack. No bidding took place in HA Operating Reserve markets.
System Conditions	[10]	ISO Stage 1 emergency on 11/19 0915-2200, 11/20 0520-2100, 12/4 0657-2200 and 12/5 0535-2200. ISO Stage 2 emergency on 11/20 1645-1900, 12/4 1600-2159 and 12/5 1600-2100.
Observations		The forced outage in the ISO's records do not show up in GADS data. Dynegy did not want to start the units because the operators were on vacation!!
Likely Overall Conclusions		The units were made unavailable (operators on vacation) during ISO emergency conditions.

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] · Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'.
[3] · From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS Reserve Shutdown event data received as Dynegy's Fourth Response to the First Set of Data Requests CAL - DYN -38.
[6] · DYN AG 155634 - 155674.
: Direct quotes from CO/Shift Supervisor logs are in quotation marks. Log summaries are in plain text and opinions are italicized.
[7] : Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] . data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
Bids in Operating Reserve markets from data request Cal-ISO-4· CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH-D: ANOMALOUS OUTAGE EVENTS

Period		3/30/01 - 6/13/01
Unit		Etiwanda 3 (Reliant)
Summary of ISO outage databases	[1]	Complete forced outage between 3/30/01 @12:45 AM and 6/13/01 @10:25 AM due to boiler tube leak and SCR work, but extended for two months due to financial reasons
Text in OutageTable	[2]	Unit O/S - Tube Leaks/ SCR work 3/30/01, 1457: Received a phone call from Kevin Frankeny reporting that the ETR of 0800, 4/2/01 given to the ISO by Matt Elliot, was incorrect and Reliant would not know the ETR until AM on 4/3/01. 2348 03/29/01 Notified NES/Elliott Etiwanda Unit 3 is to remain on line and available If Unit 3 is Forced out with tube leaks, work is to be expedited (work around the clock) so the unit can be returned to service ASAP. 0045 3/30/01 Unit 3 Forced out of service, tentative ETR 4/2/01 @ 0800 Elliott/Olson 04/03/01 1626 Per NES/David the management should be in around 0500 hrs tomorrow, 04/04/01 OK, I will make a new ETR of 0800 on 04/04/01 TPD 04/04/01 1155 - Per NES/Frankeny, outage is extended to 6/11/01 1155 Frankney notfied Sal Cardinale that he dissussed this return date with Greg Van Pelt and was passing on to realtime that they intend to proceed with this exteneded outage even though realtime operations requested that this unit be returned when the tube leak was repaired. Frankney says the reasons are financial. 06/12/01 0630 - Per NES/Elliot, no word yet on this unit.
Availability Log Information	[3]	Outage Key: 553611 3/30/2001 12:45 AM (0 MW) 6/13/2001 10 25 AM (320 MW)
Text in General Log	[4]	Not available.
Summary of GADS info	[5]	A complete planned outage for full capacity between 3/30/01 12:44 AM and 6/19/01 04.30 AM in order to install SCR and inspect turbine.
Text in GADS (if outage reported)	[5]	Other SCR problems Install SCR + HP/IP Turb Insp
Summary of Shift Supervisor Log	[6]	Not available.
RMR Unit?	[7]	Yes
Generation during the period?	[8]	During the overlap of ISO Stage 1 emergencies and the outage, there was no metered generation.
Bid in BEEP Stack and HA Operating Reserves Markets?	[9]	During the overlap of ISO Stage 1 emergencies and the outage: No bidding took place in the BEEP Stack No bidding took place in HA Operating Reserve markets
System Conditions	[10]	2 Stage 3, 13 Stage 2, and 13 Stage 1 emergencies during the period.
Observations		ISO notified Reliant that the unit should remain on-line. If a forced outage occurs, the repairs should be done around the clock to make the unit available ASAP. However, the outage took more than 2 months due to "financial" reasons.
Likely Overall Conclusions		

[1] : CAISO's SLIC Databases: Outage Table (outage_tbl), Availability Table (gen_abail_tbl).
[2] : Combined text fields from fields 'equipment', 'outage coordinator text', and 'dispatch text'
[3] : From fields PNT_DTS_PDT, UA_AVAIL, OUTAGE_KEY.
[4] : Not available.
[5] : GADS Event Data (Report 97). Received in response to CA -REL -1-35
[6] : Not available.
[7] . Unit characteristics and ownership identification derived from ISO data provided by the CA Attorney General.
[8] : data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
[9] : BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
· Bids in Operating Reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.
[10] : List of CAISO-declared emergency periods from http.//www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.xls.

APPENDIX PQH - E: RESERVE SHUTDOWNS DURING SYSTEM EMERGENCY PERIODS

		Reserve Shutdown Period				Overlap with ISO-Declared Emergencies			
Supplier	Unit Name	Start Date	End Date	Duration (hrs)	Emergency Periods	Overlap with Stage 1 (hrs)	Overlap with Stage 2 (hrs)	Overlap with Stage 3 (hrs)	Generation and Bid
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Duke	OAK C_7_UNIT 2	11/20/00 10:00	11/20/00 15.00	5	Stage 1: 0520-2100	5			Condition 2 RMR
Duke	OAK C_7_UNIT 3	11/20/00 10:00	11/20/00 15:00	5	Stage 1: 0520-2100	5			Condition 2 RMR
Duke	SOBAY_7_GT1	9/18/00 21:16	9/19/00 15:59	19	9/19/00. Stage 1 1100 - 2200	5			No generation or bidding.
Dynegy	ELSEGN_7_UNIT 1	11/18/00 0:06	12/1/00 0:00	312	11/19/00: Stage 1: 0915-2200 11/20/00: Stage 1: 0520 - 2100 Stage 2 1645 - 1900	28	2		No generation or bidding
Dynegy	ELSEGN_7_UNIT 2	6/27/00 0:00	6/27/00 18:00	18	Stage 1: 1000 - 2020 Stage 2: 1330 - 1900	8	5		No generation or bidding
Dynegy	ELSEGN_7_UNIT 2	7/12/00 23:00	7/20/00 10:06	179	7/19/00: Stage 1: 1450 - 1900 Stage 2: 1450 - 1800	4	3		No generation or bidding
Dynegy	ELSEGN_7_UNIT 2	11/1/00 0:00	11/15/00 0:32	337	11/13/00: Stage 1: 1658 - 2046 Stage 2: 1713 - 2048	4	4		No generation or bidding
Dynegy	ELSEGN_7_UNIT 2	11/18/00 0:20	12/1/00 0 00	312	11/19/00: Stage 1: 0915-2200 11/20/00: Stage 1. 0520 - 2100 Stage 2: 1645 - 1900	28	2		No generation or bidding
Dynegy	Long Beach 6	5/1/00 0:00	6/1/00 0.00	744	5/22/00: Stage 1: 1030 - 1800 Stage 2: 1230 - 1700	8	5		No generation or bidding
Dynegy	Long Beach 7	5/1/00 0:00	6/1/00 0.00	744	5/22/00: Stage 1: 1030 - 1800 Stage 2: 1230 - 1700	8	5		No generation or bidding.

APPENDIX PQH - E: RESERVE SHUTDOWNS DURING SYSTEM EMERGENCY PERIODS

		Reserve Shutdown Period				Overlap with ISO-Declared Emergencies			
Supplier	Unit Name	Start Date	End Date	Duration (hrs)	Emergency Periods	Overlap with Stage 1 (hrs)	Overlap with Stage 2 (hrs)	Overlap with Stage 3 (hrs)	Generation and Bid
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Mirant	POTRPP_7_UNIT 4	3/6/01 19:46	3/16/01 22:35	243	3/15/01. Stage 1&2: 1030 - 2159	11	11		No generation or bidding
Mirant	POTRPP_7_UNIT 5	3/13/01 16.34	3/18/01 18:52	122	3/15/01: Stage 1&2: 1030 - 2159	11	11		No generation or bidding
Mirant	POTRPP_7_UNIT 6	11/17/00 9:37	11/20/00 5:23	68	11/19/00: Stage 1: 0915-2200	13			No generation or bidding
Mirant	POTRPP_7_UNIT 6	11/20/00 9:22	11/29/00 9:40	216	11/20/00: Stage 1. 0520 - 2100 Stage 2 1645 - 1900	12	2		No generation or bidding.
Mirant	POTRPP_7_UNIT 6	2/2/01 2:20	2/5/01 3:50	74	2/2/01 - 2/5/01: Stage 1, 2, & 3: 0001 - 2359	73	73	73	No generation or bidding.
Mirant	POTRPP_7_UNIT 6	3/6/01 19:43	3/18/01 18.51	287	3/15/01: Stage 1 &2: 1030 - 2159	11	11		No generation or bidding
Reliant	COOLWATER #4 CT #1	4/16/01 1:15	5/4/01 0:20	431	4/24/01: Stage 1: 1337 - 2359 Stage 2. 1405 - 2359 4/25/01: Stage 1&2: 1518 - 2159	17	17		No generation or bidding
Reliant	COOLWATER #4 CT #2	4/16/01 0:18	5/2/01 22:35	406	4/24/01: Stage 1: 1337 - 2359 Stage 2: 1405 - 2359 4/25/01: Stage 1&2: 1518 - 2159	17	17		No generation or bidding
Reliant	COOLWATER #4 ST	4/16/01 0:52	5/4/01 11:59	443	4/24/01: Stage 1. 1337 - 2359 Stage 2: 1405 - 2359 4/25/01: Stage 1&2: 1518 - 2159	17	17		No generation or bidding
Reliant	ETIWND_7_UNIT 2	12/21/00 12:06	12/26/00 1.25	109	12/23/00: Stage 1 & 2: 0022 - 2200 12/24/00: Stage 1: 0920 - 2200	34	22		No generation or bidding

APPENDIX PQH - E: RESERVE SHUTDOWNS DURING SYSTEM EMERGENCY PERIODS

		Reserve Shutdown Period				Overlap with ISO-Declared Emergencies			
Supplier	Unit Name	Start Date	End Date	Duration (hrs)	Emergency Periods	Overlap with Stage 1 (hrs)	Overlap with Stage 2 (hrs)	Overlap with Stage 3 (hrs)	Generation and Bid
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Reliant	ETIWND_7_UNIT 5	2/25/01 20.17	3/9/01 10:26	278	2/28/01. Stage 1: 1000 - 2359 Stage 2. 1000 - 2000 3/1/01: Stage 1 & 2: 0650 - 1000 3/5/01: Stage 1· 0800 - 2359	33	13		No generation or bidding.
Reliant	GOLETA_6_ELLWOD	4/9/01 15.35	5/6/01 0:01	632	4/24/01: Stage 1· 1337 - 2359 Stage 2: 1405 - 2359 4/25/01· Stage 1 & 2. 1518 - 2159	17	10		No generation or bidding

Sources and Notes:

[1], [2]: 'Reserve shutdown data comes from the following sources for each supplier.

Duke: GADS event data received in response to CAL-DUKE-58 and CAL-DUKE-163 on 1/29/03.

Dynegy: GADS event data for the El Segundo plants received as Dynegy's Fourth Response to the First Set of Data Requests CAL - DYN -38.
GADS event data for the Long Beach plants received as Dynegy's Fourth Response to the First Set of Data Requests CAL - DYN -38.

Mirant: GADS event data received on 2/3/03 in response to CAL-MIR-58 in CD 1278.

Reliant: GADS Event Data (Report 97). Received in response to CA -REL -1-35.

[3]: ([2] - [1])*24

[4]· List of CAISO-declared emergency periods from http://www.caiso com/docs/09003a6080/08/8a/09003a6080088aa7 xls

[5] - [7]: Number of hours overlapping between an ISO emergency and reserve shutdown event.

[8] : Bid in BEEP Stack and the Hour_Ahead Operating Reserve Markets.
: BEEP Stack data from data request Cal-ISO-1: CAL_ISO_1_Engy_xxxx.csv files.
: Bids in operating reserve markets from data request Cal-ISO-4: CAL_ISO_4_Gen_Sch2_xxxx.csv files.

The averages in [8] reflect an average of all the hours overlapping between the reserve shutdown event and the Stage 1 emergency periods

APPENDIX PQH – F

Comparison of National and California Outage Rates

1. I have examined and compared available data on national and California generating units' outage rates. This is sometimes known as a "benchmark analysis."

2. The benchmark analysis I have done compares performance statistics observed at the power generation units that AES, Duke, Dynegy, Mirant, and Reliant operate in California to a national benchmark of power generation units. I examined 81 units in the Sellers' group. The benchmark consists of all units of the same technology as the Sellers' units with a positive net capacity factor in the year 2000. Any patterns in the deviation of the statistics measured at the Sellers' units from those measured at units of the national benchmark would need to be explained by factors idiosyncratic to the Sellers' units.

3. I performed the analysis for two measures of a generating unit's availability for the generation of power. These are net capacity factor ("NCF") and a proxy for equivalent forced outage rate ("EFOR").

   The net capacity factor of a generating unit is a measure of how much of its potential output a unit actually generated over a given period. It is calculated by the following formula:

A. Yes, I examined the relationship of such bid mark-ups to market conditions and to each individual Seller's position in the market at the time of the bids. If the bid mark-ups of the Sellers is independent of their costs, then clearly they are capable of exercising market power. However, I examined the relationship between the bid mark-ups and what I call condition variables, specifically the tightness of the market and the depth of Sellers' positions in the market, to see if there was a systematic relationship between them. If the bid mark-ups increase with the tightness of the market or with the depth of Sellers' holdings in the market, then clearly the Sellers not only possess market power but they are also exercising it intentionally based upon opportunities presented in the marketplace and their own ability to capitalize upon increased prices.

Q. Why did you choose to examine these two particular features of the market, market tightness and Sellers' market position?

A. I chose these two features of the market to examine because one speaks to a Seller's opportunity to exercise market power while the other speaks to a Seller's motive. As the Commission has recognized, the tighter the market, the easier it is for a seller that has market power to exercise it. A market whose demand is large relative to the resources available to supply that demand is relatively easy prey for a Seller with resources of significance in size to the market. The FERC has noted that when markets are particularly tight, even

It effectively converts forced derated hours into an equivalent number of forced outage hours. The numerator of EFOR is thus the equivalent of how many hours the unit was on forced outage. The denominator is the number of hours that the unit was either forced off-line, running or the equivalent of forced off-line during a reserve shutdown. The EFOR ranges from 0 to 100.

5. I used three datasets to perform my analysis. One is the NERC's GADS event formatted data for each of the Sellers' units from the beginning of 2000 until the end of May, 2001.[5] The second dataset is a subset of the NERC personal computer-Generating Availability Report ("pc-GAR") that shows national monthly performance data for the years 1994 through 2000. The third dataset details hourly generation for the units in the California group from the beginning of 2000 until the end of June, 2001. The California ISO provided this in response to data requests.[6] I use earlier generation data, covering April 1998 until December 1999 also provided by CAISO to complement the 2000 and 2001 dataset.

6. The GADS event data provide detailed information on the generation-impeding events that take place over the year. This includes the start time and date of an event, the end time and date, the type of event, the net available capacity as a result of the event, and a cause code that associates a component with the event. The events that

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[5] Note that AES did not supply GADS event formatted data. We used hourly availability data supplied to calculate event-based data.
[6] CAISO CD 1534.

are of interest in my analysis are all types of events that forced the unit to reduce its generation. These are: 1) all three types of forced outages, 2) all three types of forced deratings, and 3) startup failures.

7. The pc-GAR database provides detailed performance data for all power generating units reporting to NERC's GADS. This includes variables such as net actual generation, service hours, forced outage hours, equivalent forced derated hours, net capacity factor, and EFOR.

8. As the GADS event data do not include information about service hours, I did not calculate EFOR for the California units. Instead I construct an EFOR proxy ("EFORP") for both the California units and the national benchmark. The formula for EFORP is:

   (Forced Outage Hours + Equivalent Forced Derated Hours) ÷ Period Hours

9. My analysis consists of the following:

   a) I examined the average seasonal EFORP for the California group in relation to the average seasonal EFORP for the national benchmark and a confidence band that I constructed around it. I performed this comparison grouped by all existing combinations of unit technology and the choice of unit age ranges. Additionally, I provided a capacity-weighted average seasonal EFORP for each technology group among both the Sellers' units and the national benchmark units. I also constructed the appropriate capacity-weighted confidence band around the national benchmark seasonal average.

b) I examined the average seasonal NCF for the California group in relation to the average seasonal NCF for the national benchmark and a band constructed around it over time. I also group this by all existing combinations of unit technology and unit age ranges. Additionally, I calculated the capacity-weighted average seasonal NCF for each technology group among the Sellers' units and the national benchmark. I also constructed the appropriate capacity-weighted confidence band around the national benchmark seasonal average.

c) I compared the average EFORP of the California group in the first half of the year 2000, the second half of 2000, and the first half of 2001 to the same measures in the national benchmark. The measures were again grouped by technology and age. In this comparison I also showed the capacity factor in the prior one-year period associated with each group. Additionally, I calculated the ratio of EFORP to NCF for both groups of units.

All the units in the Sellers' group use one of three types of technology: 1) combustion turbine burning fuel oil ("CTFO"); 2) combustion turbine burning natural gas ("CTNG"); and 3) steam turbine burning natural gas ("STNG"). Based on its age, I assigned one of the following age brackets, given in years, to each unit in the California group: 21-25, 26-30, 31-35, 36-40, 41-45, and 46-50. I use the same age brackets for obtaining national benchmark data from pc-GAR. The following were the combinations among the Sellers' units: CTFO, 21-25; CTFO, 26-30; CTFO, 31-

35; CTNG, 21-25; CTNG, 26-30; CTNG, 31-35; STNG, 26-30; STNG, 31-35; STNG, 36-40; STNG, 41-45; STNG, 46-50. Appendix PQH-F, Table 1 shows, for the California group and the national benchmark, the number of units in each technology/age grouping, the sum of the net maximum capacity of these units, and their average net maximum capacity.

10. I performed my calculations as follows:

a) Using the aforementioned formula, I calculated the EFORP for each event that occurred at one of the Sellers' units. From this I calculated the monthly EFORP at each unit by summing all EFORP for each month. Using the classification of technology and the age bracket associated with each unit, I then calculated the monthly average EFORP for each existing combination of technology and age. Since I could not be certain about when the event-formatted data that generators supplied began, I had to establish a decision rule on how to treat the months prior to the first reported event. It could have been that the data for these months were missing. Alternatively, the generator might not have experienced a forced outage or derating. In these cases, I inspected the CAISO SLIC records[7] for the same generator. If I found a forced outage or derating prior to the first event provided by the Seller in the SLIC records, I assigned a missing value to the monthly average EFORP for every month before the first event provided by the Seller. If I did not find a forced event in the SLIC records prior to the first Seller-provided

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[7] See Appendix PQH-C.

event, I assumed that no forced events took place since the beginning of the year in all months prior to the first Seller-provided event and set the monthly EFORP for those months to zero.

I used the values that I arrived at to calculate a seasonal average EFORP for each technology/age grouping. In doing this I counted December, January, and February as winter months, March, April, and May as spring months, June, July, and August as summer months and September, October, and November as fall months. The results of these calculations are shown in Appendix PQH-F, Table 2.

I calculated the EFORP for the national benchmark from the average monthly forced outage hours and equivalent forced derated hours reported in the NERC pc-GAR database for each grouping of technology and age bracket. These are summarized in Appendix PQH-F, Table 3. As no 2001 pc-GAR data is available from NERC, I cannot calculate EFORP for the national benchmark for 2001.

Additionally, I calculated the national benchmark seven-year seasonal average over the years 1994 through 2000. The result is one average for each season: winter, spring, summer, and fall. Along with the seasonal average, I determined other key statistics: median, standard deviation over the time period observed, minimum, and maximum. These allowed me to construct a confidence band around the seasonal average by calculating an upper bound and a lower bound. The lower bound is defined as either the average minus two standard deviations or the minimum observed value, whichever is bigger. The upper bound is defined similarly as either the average plus two standard deviations or the maximum observed value, whichever is smaller. The results of these calculations are shown in Appendix PQH-F, Tables 4A through 4C.

A graphical representation of each technology/age grouping's average seasonal EFORP compared to the national benchmark's average seasonal EFORP and the upper and lower bound of the national benchmark's seven-year average seasonal EFORP is shown in Appendix PQH-F, Figures 1 through 10.

Finally, I created a capacity-weighted seasonal average EFORP for each technology grouping for both the national benchmark and the California units. I did this by multiplying the seasonal average EFORP for each technology/age grouping by the sum of the net maximum capacity of all the units in the group. I then added these together for the same technologies and divided the result by the sum of the net maximum capacity of all the units in the same technology group. Similarly, I weighted the upper and the lower bound of the confidence band by capacity. A graphical representation of the capacity weighted seasonal average EFORP for each technology over time is shown in Appendix PQH-F, Figures 11 through 13.

b) Using a dataset that details hourly generation for each of the California units[8], I calculated an hourly NCF for each of them. I then used these to calculate a

[8] CAISO CD 1534.

monthly capacity factor. Using the technology and age bracket assigned to each California unit, I calculated a monthly average NCF for each combination of technology and age among the California units. I used these values to compute a seasonal average for each technology/age grouping. I assigned months to the same seasons as I describe above in my treatment of EFORP seasonal averages.

For the national benchmark, I took the average NCF that is reported in pc-GAR for the relevant month. Using the same technology and age combinations, I calculated a monthly average NCF for each combination. I used these numbers to construct a seasonal average. The results are shown in Appendix PQH-F, Tables 5 and 6.

Using a comparable method as detailed above in my treatment of EFORP, I calculated a seasonal mean that averages the monthly NCF provided by pc-GAR from 1994 through 2000. I also determine the median, the standard deviation over the period observed, and the minimum and maximum values observed. I construct a confidence band around the seven-year seasonal averages. This band has an upper and a lower boundary defined similarly to the band for EFORP. The lower boundary is the higher of either the minimum value observed or the seasonal average minus two standard deviations. The upper boundary is defined as the lesser of either the maximum value observed or the seasonal average plus two standard deviations. The results of these calculations are shown in Appendix PQH-F, Tables 7A through 7C.

A graphical representation of each technology/age grouping's average seasonal NCF compared to the benchmark's average seasonal NCF and the upper and lower bound of the national benchmark's seven-year average seasonal NCF is given in Appendix PQH-F, Figures 14 through 23.

I also created a capacity-weighted seasonal average NCF for each technology grouping for the national benchmark and the California units. I did this in a manner analogous to my methodology for calculating capacity-weighted seasonal average ERFORP by multiplying the seasonal average NCF for each technology/age grouping by the sum of the net maximum capacity of all the units in the group. I then added these together for the same technologies and divided the result by the sum of the net maximum capacity of all the units in the same technology group. In the same way, I weighted the upper and the lower bound of the confidence band by capacity. A graphical representation of the capacity weighted seasonal average NCF for each technology over time is shown in Appendix PQH-F, Figures 24 through 26.

c) Having calculated monthly average EFORP for each technology/age combination for both the California units and the national benchmark, I also aggregated these data into averages for the first half of 2000, the second half of 2000, and the first half of 2001. I defined the first half of a year to range from December of the previous year through May of the given year, and I defined the second half to range from June through November. I did this to match with the earlier seasonal definitions. Thus, the first half of a year captures winter and spring, and the second half captures summer and winter. The calculation excluded months for which no data are present. For the national benchmark no data were present after December 2000. To examine whether there is any correlation between the performance of the California units in a given period and prior utilization of the generating capacities of a unit, I calculated the average NCF in the one-year timespan prior to and including the given period. Thus, for the first half of 2000, I calculated the average NCF between June 1999 and May 2000; for the second half of 2000, I calculated the average NCF between December 2000 and November 2000; and for the first half of 2001, I calculated the average NCF between June 20000 and July 2001. For the national benchmark no data were available for the first half of 2001. Therefore, the NCF for this period is missing.

I normalized the relation between EFORP and NCF by dividing EFORP by its corresponding NCF. This measure enabled me to compare the California group directly to the national benchmark. The higher this measure is, the more a unit was forced off-line relative to its generating utilization.

The findings of this analysis are summarized in Appendix PQH-F, Tables 8, 9, and 10.

11. The following are the conclusions I draw from my analysis:

a) Appendix PQH-F, Tables 8, 9, and 10 show the comparison of EFORP to NCF in the prior year for the first half of 2000, the second half of 2000, and the first half of 2001. In the first half of 2000, the EFORP was bigger for the California units than for the benchmark in six out of ten available technology/age categories of units[9]. In the second half of 2000, the same was true for nine of eleven cases. In the first half of 2001 no such measurement could be made because of a lack of national data beyond the year 2000.

The average NCF for the California units prior to and including the first half of 2000 was bigger than that of the national benchmark in seven of eleven cases. In the second half of the year that was the case for nine of eleven instances. This indicates that in the year prior to and including the second year of 2000, the California units on average ran more than the national benchmark units. Again, no such comparison can be made for the first half of 2001.

In the first half of 2000, in four out of ten cases, the EFORP/NCF ratio was higher for the California units than for the national benchmark. It suggests that the California units were going off-line less for a given level of generating utilization than the national benchmark was.

In the second half of 2000, the situation was reversed. In seven out of eleven cases, the California units had a higher EFORP/NCF ratio in this period than did the national benchmark. This suggests that during this period, the California units were

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[9] No data was available for the CTFO units between age 26 and 30 for this period.

going off-line more than the benchmark units were for a given level of generating utilization.

In the first half of 2001, again no benchmark comparison can be made, as no national data is available for 2001. However, the EFORP/NCF ratio for the Sellers' units is lower than the ratio for the same technology/age grouping in the second half of 2000 for four of the eleven groups. This suggests that in this period the California units were going off-line less often for a given level of generating utilization in the first half of 2001 than they were in the second half of 2000.

b) The capacity-weighted average EFORP for Sellers' CTFO units started below the national benchmark but rose above it. It exceeds the upper bound of the confidence band in summer 2000. In the spring of 2001 it peaks and declines to a level that is still well above the upper bound in summer 2001. This is shown graphically in Appendix PQH-F, Figure 11. The high EFORP is driven mainly by the younger units (age 21-25), which exceed the upper bound of the confidence band in Summer 2000 and stay high above it throughout the rest of the period, while older units (31-35) fall below the upper bound during most periods.[10]

c) The capacity-weighted average EFORP of Sellers' CTNG units started below the benchmark's average and climbed above it in spring 2000. In fall 2000 it rises above the upper bound of the confidence band and peaks in summer 2001. This is shown graphically in Appendix PQH-F, Figure 12.

d) The capacity-weighted average EFORP of Sellers' STNG units was above the national benchmark average over the entire period. From summer 2000 until spring

[10] I omit a graph for the CTFO 26-30 grouping since the only unit in this group is Goleta Ellwood.

2001 the California units' EFORP was above the upper bound of the confidence band, peaking in winter 2000/2001. This is shown graphically in Appendix PQH-F, Figure 13.

e) Thus, for all technologies, outage rates were very high compared to the national benchmark from winter 2000 until summer 2001. For STNG and CTFO units, this was also true for earlier periods, specifically from the summer of 2000 onwards.

f) For Sellers' CTFO units, the capacity-weighted average NCF stays fairly constant from spring 1999 until spring 2000, usually close to and above the national benchmark, falling below it in the summers when the benchmark average rises. In the summer of 2000 the average NCF rises above the upper bound and remains well above it until spring 2001. It peaks in winter 2000/2001. This information is graphically shown in Appendix PQH-F, Figure 24. The general shape of this Figure is reflected in both the younger and the older CTFO units (ages 21-25 and 31-35).[11]

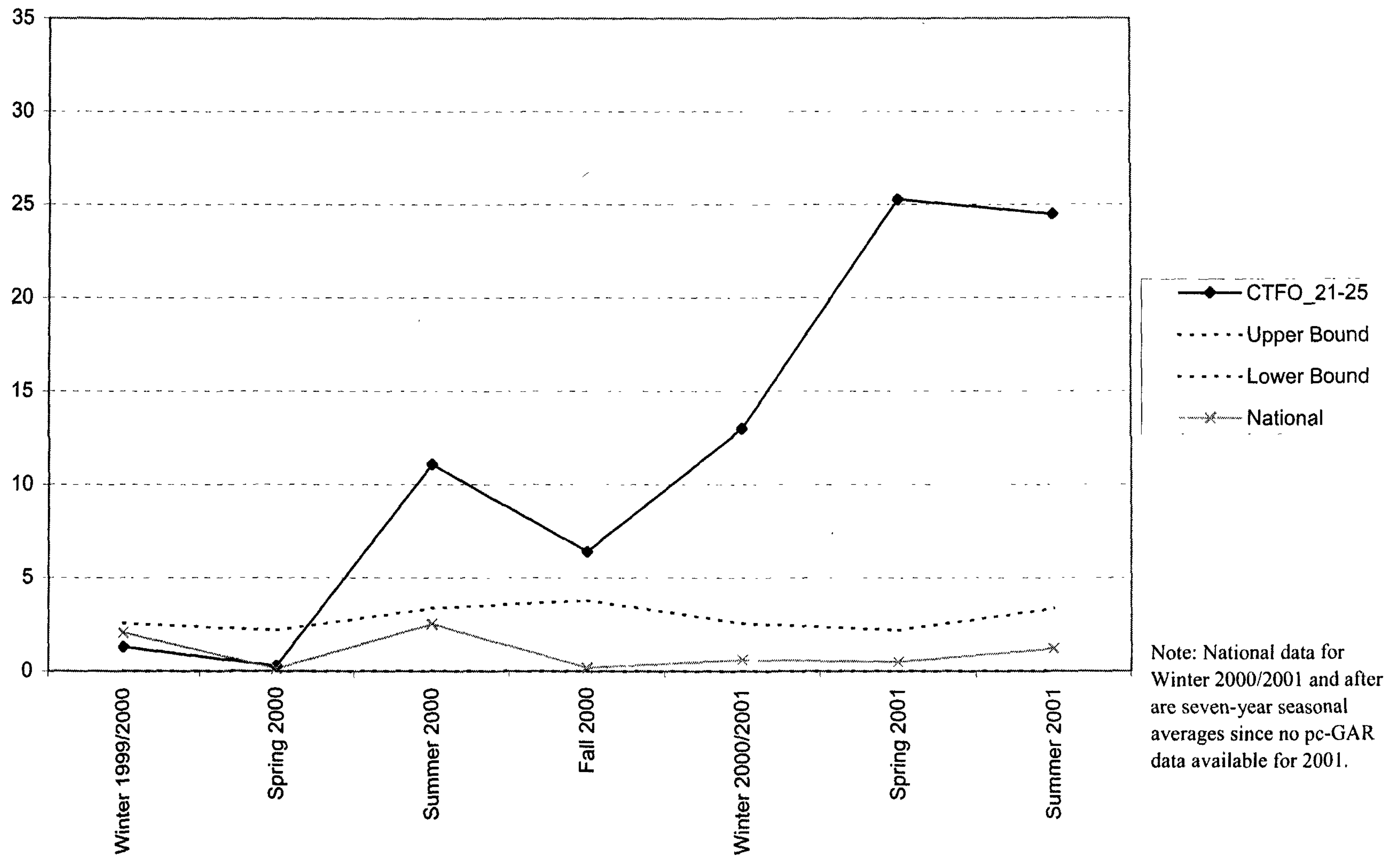
g) The capacity-weighted average NCF for CTNG units is below the benchmark's average only in spring 1998 and below the upper bound of the confidence band only in summer 1998 and spring 2000. After spring 2000 it rises again and peaks in winter 2000/2001. CTNG units were also the ones with the EFORP closest to the national benchmark over the entire period. This could indicate that an NCF that lies high above the national benchmark does not necessarily imply a similarly highly deviating EFORP. The average NCF for CTNG units is shown graphically in Appendix PQH-F,

[11] Again, I omit the CTFO 26-30 grouping in my Figures as the only Sellers' unit in this grouping is Goleta Ellwood.

Figure 25. The weighted average is driven mainly by the young units (age 21-25), which comprise about 78% of the net maximum capacity in the CTNG group.

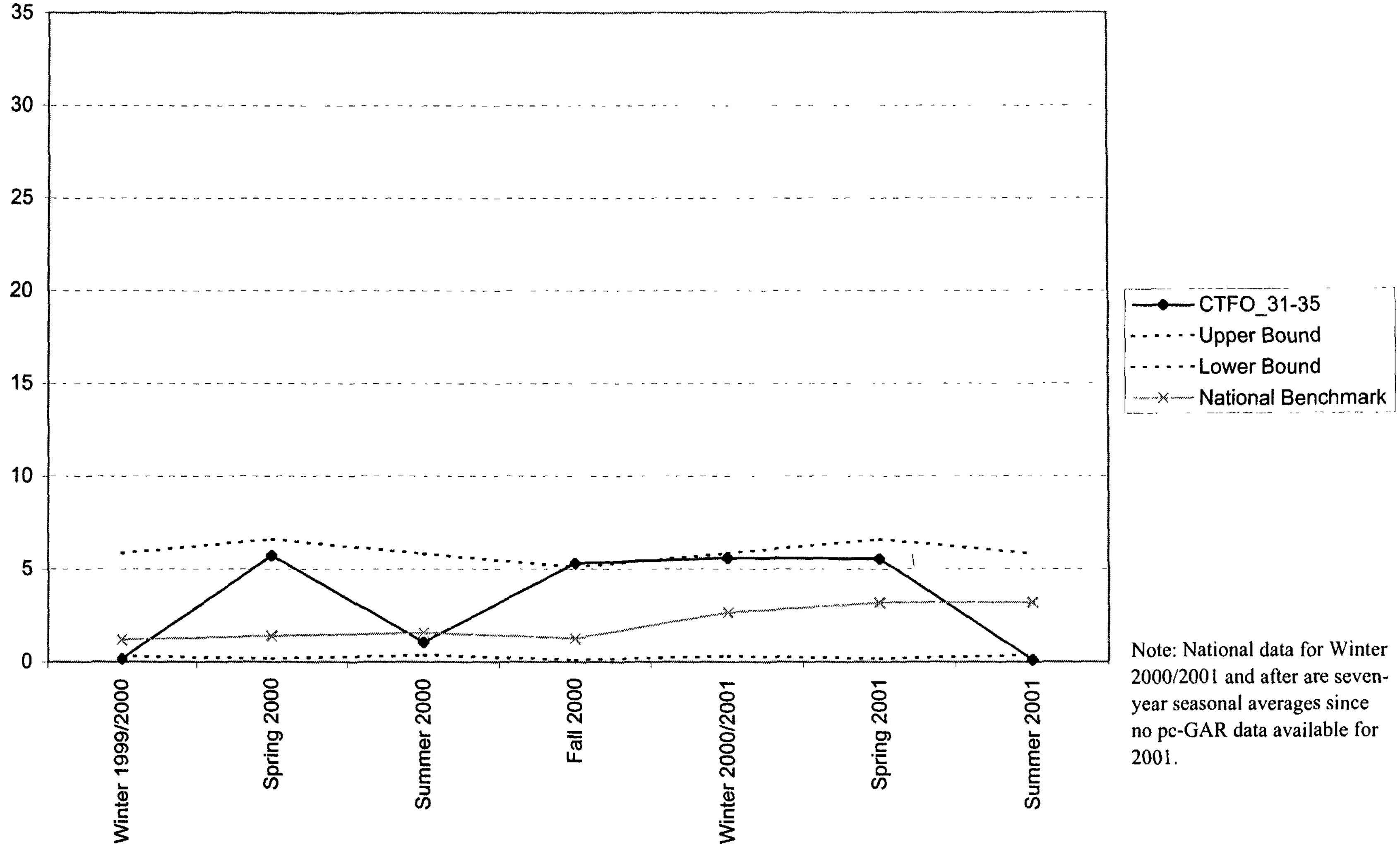
h) For Sellers' STNG units, the average NCF remains below the national benchmark for most periods prior to fall 1999. During this time, it is also below the lower bound four out of six seasons. It then briefly rises above the national average in fall 1999 and winter 1999/2000. It dips below the benchmark in spring 2000 and then in summer 2000 rises above it, close to the upper bound of the confidence band. It remains high and well above the upper bound until spring 2001. The movements of both, the national benchmark and the confidence band, fluctuate strongly (by about 30 points.) This is shown graphically in Appendix PQH-F, Figure 26.

**Appendix PQH-F, Figure 1:
EFORP Over Time - California vs National Seasonal Average**



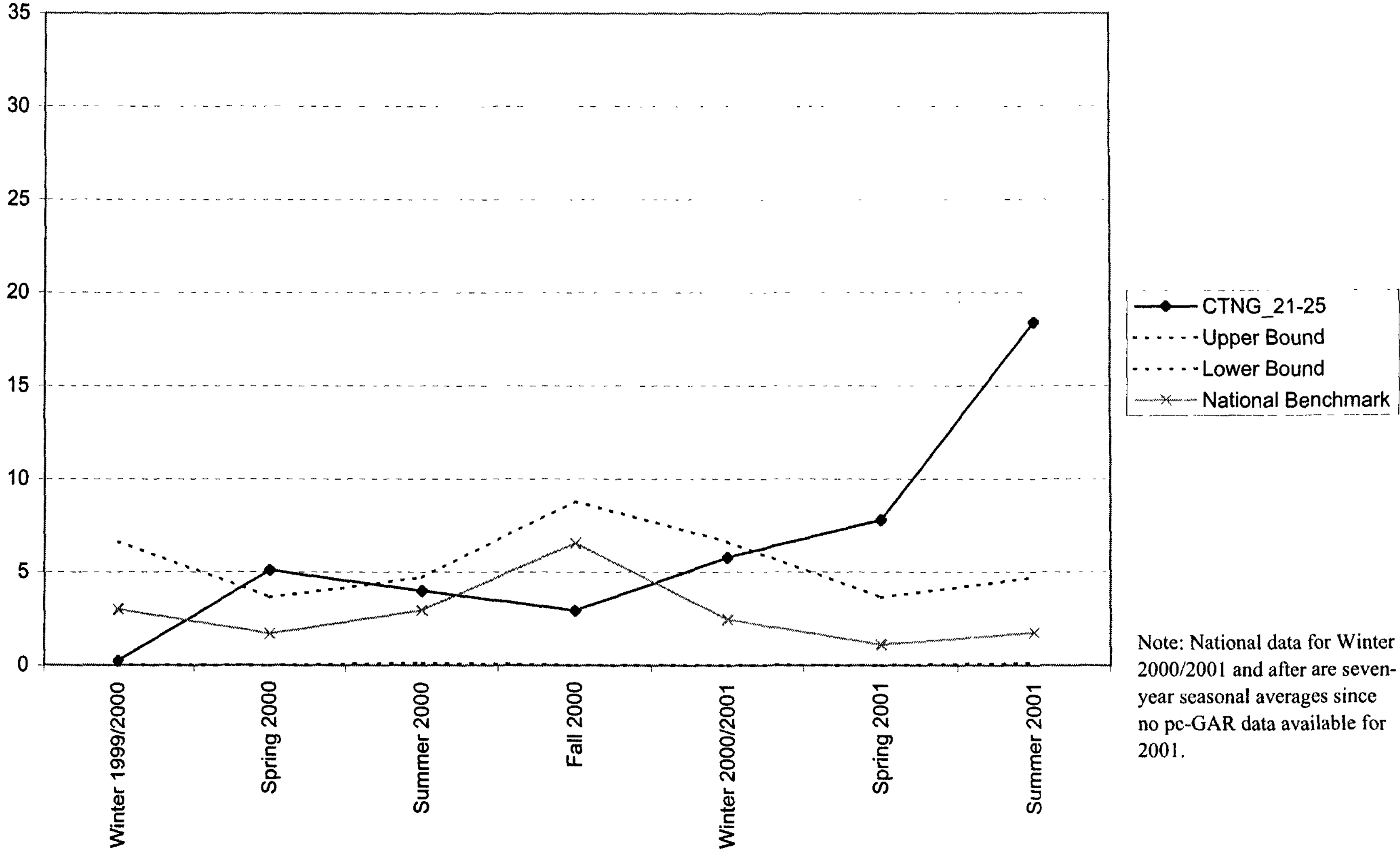
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

Appendix PQH-F, Figure 2:
EFORP Over Time - California vs National Seasonal Average



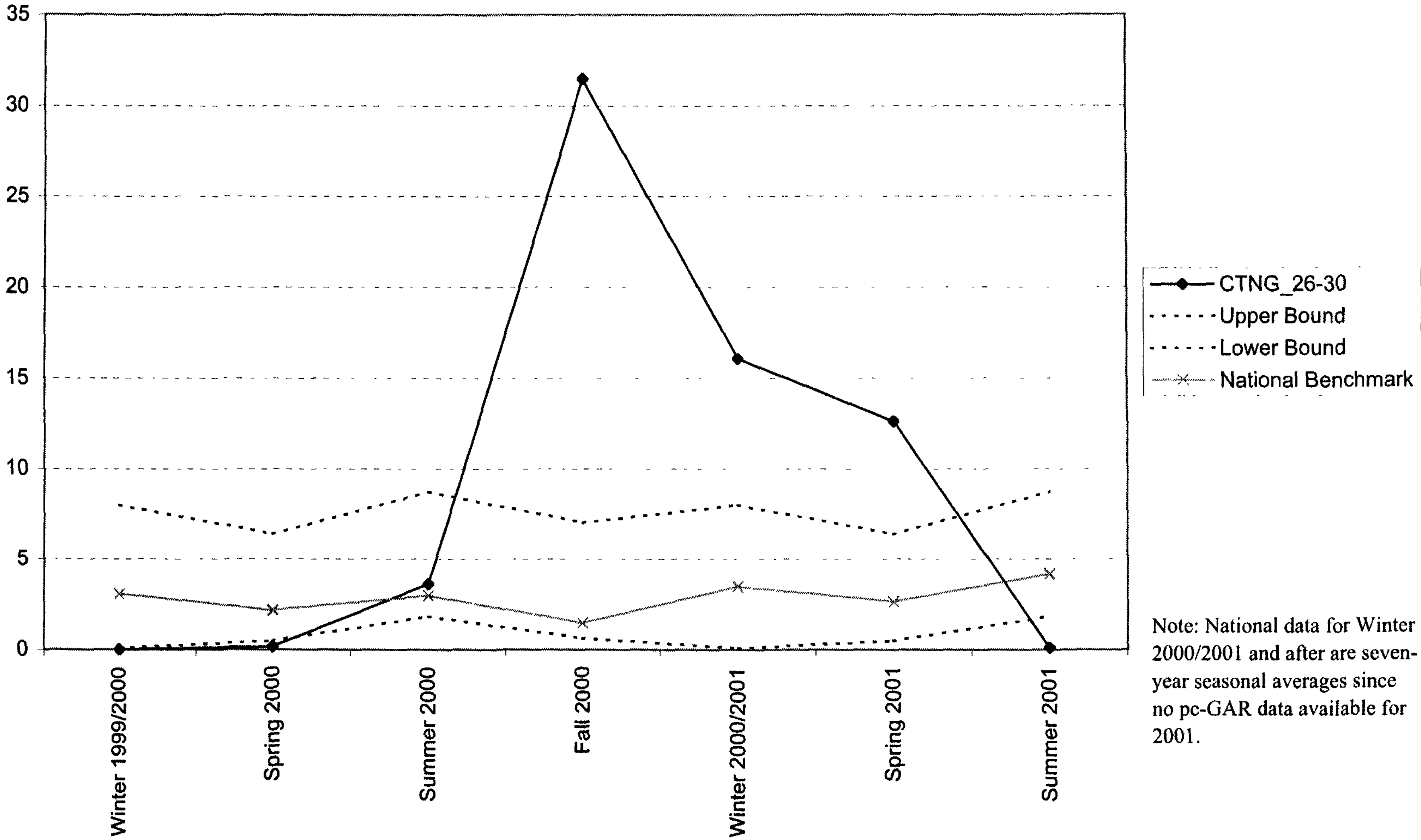
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

Appendix PQH-F, Figure 3:
EFORP Over Time - California vs National Seasonal Average



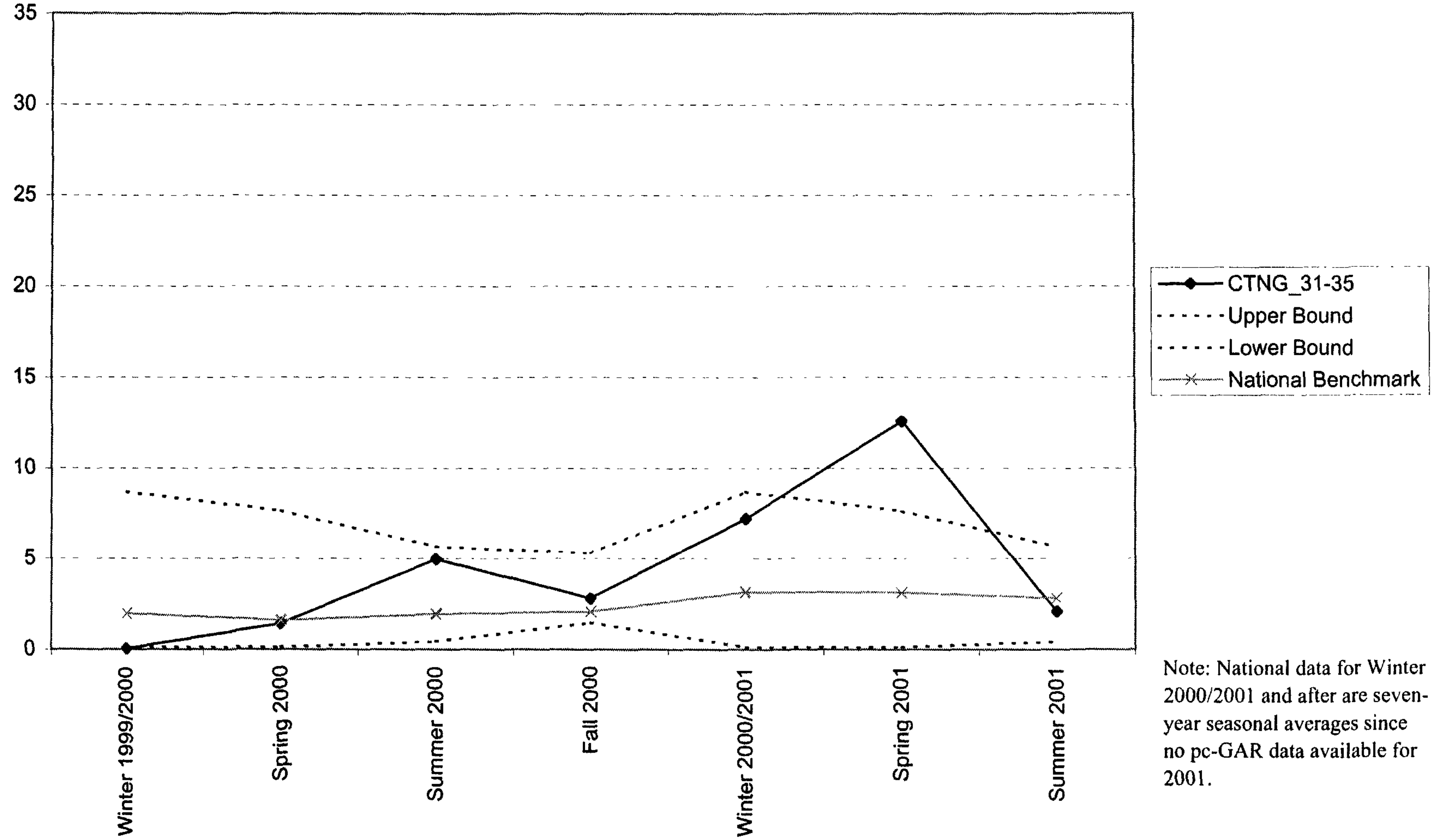
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

Appendix PQH-F, Figure 4:
EFORP Over Time - California vs National Seasonal Average



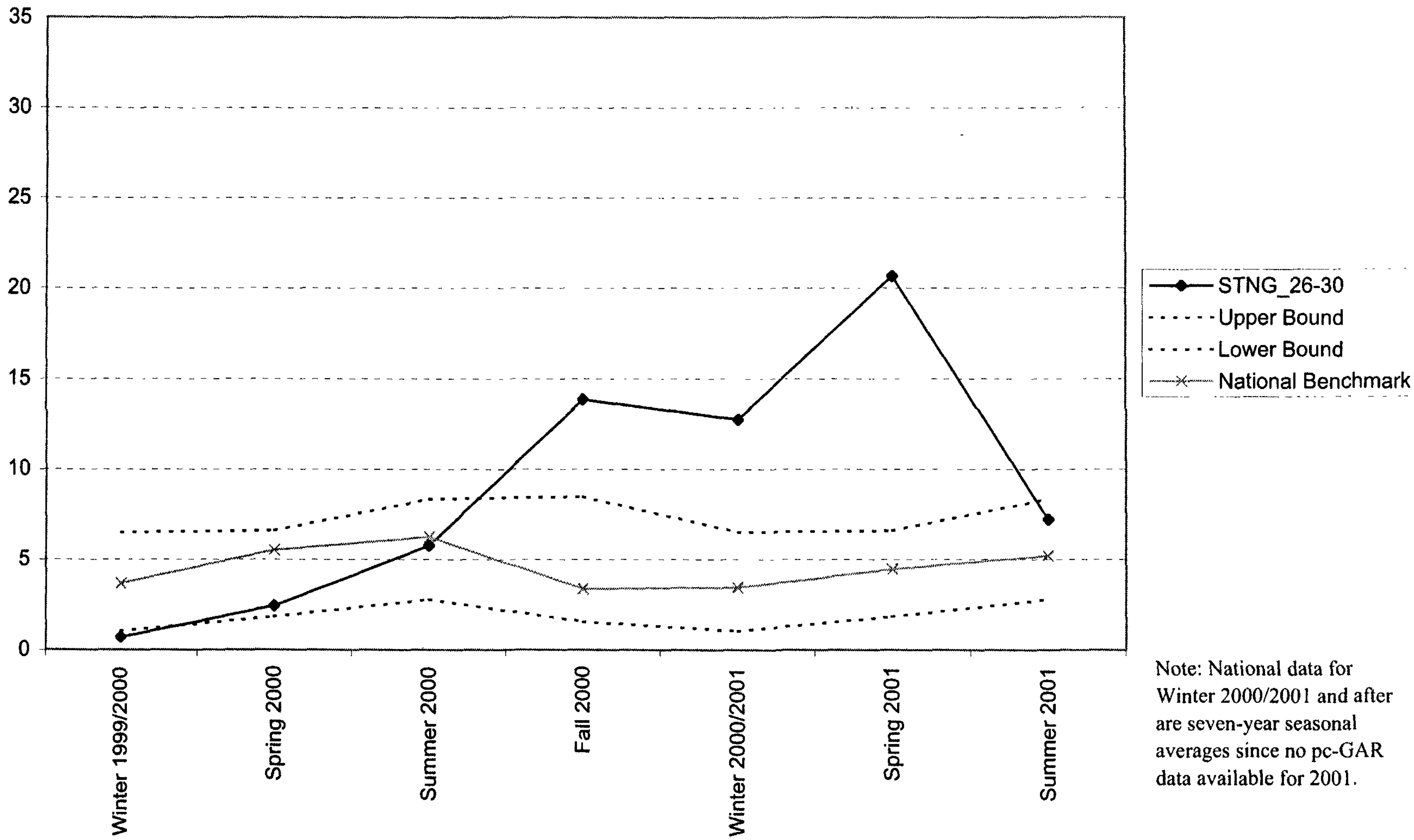
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

**Appendix PQH-F, Figure 5:
EFORP Over Time - California vs National Seasonal Average**



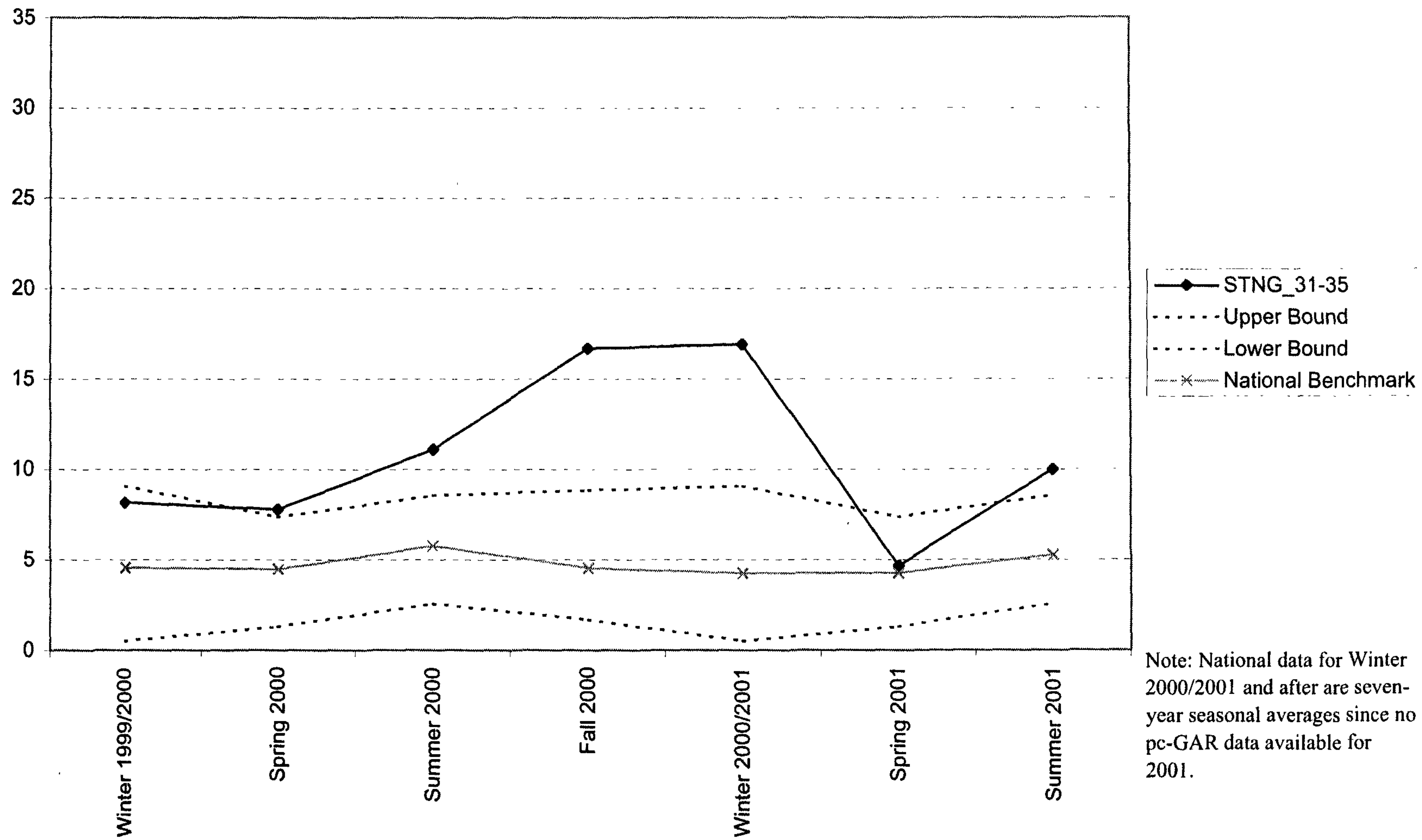
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

**Appendix PQH-F, Figure 6:
EFORP Over Time - California vs National Seasonal Average**



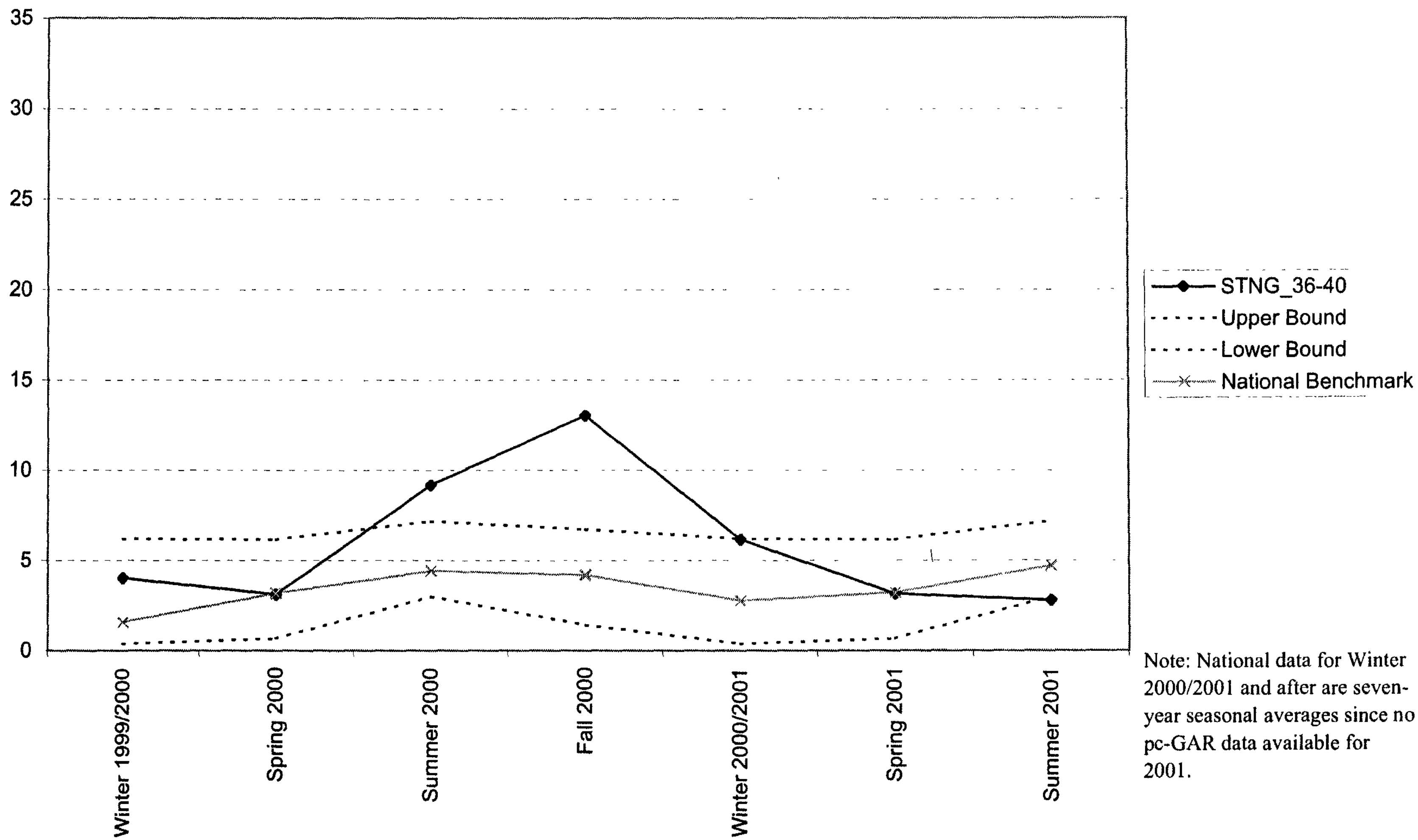
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

**Appendix PQH-F, Figure 7:
EFORP Over Time - California vs National Seasonal Average**



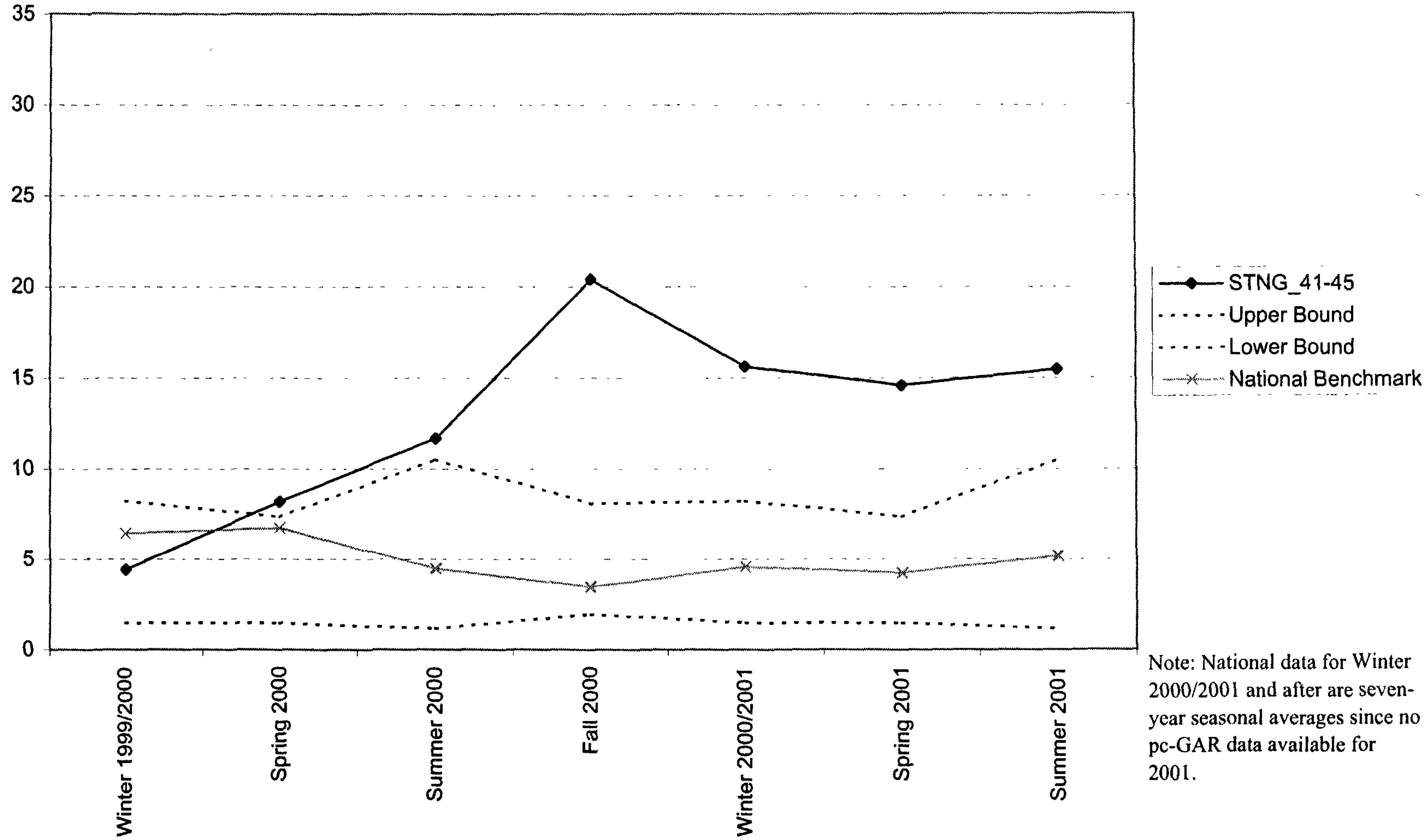
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

Appendix PQH-F, Figure 8:
EFORP Over Time - California vs National Seasonal Average



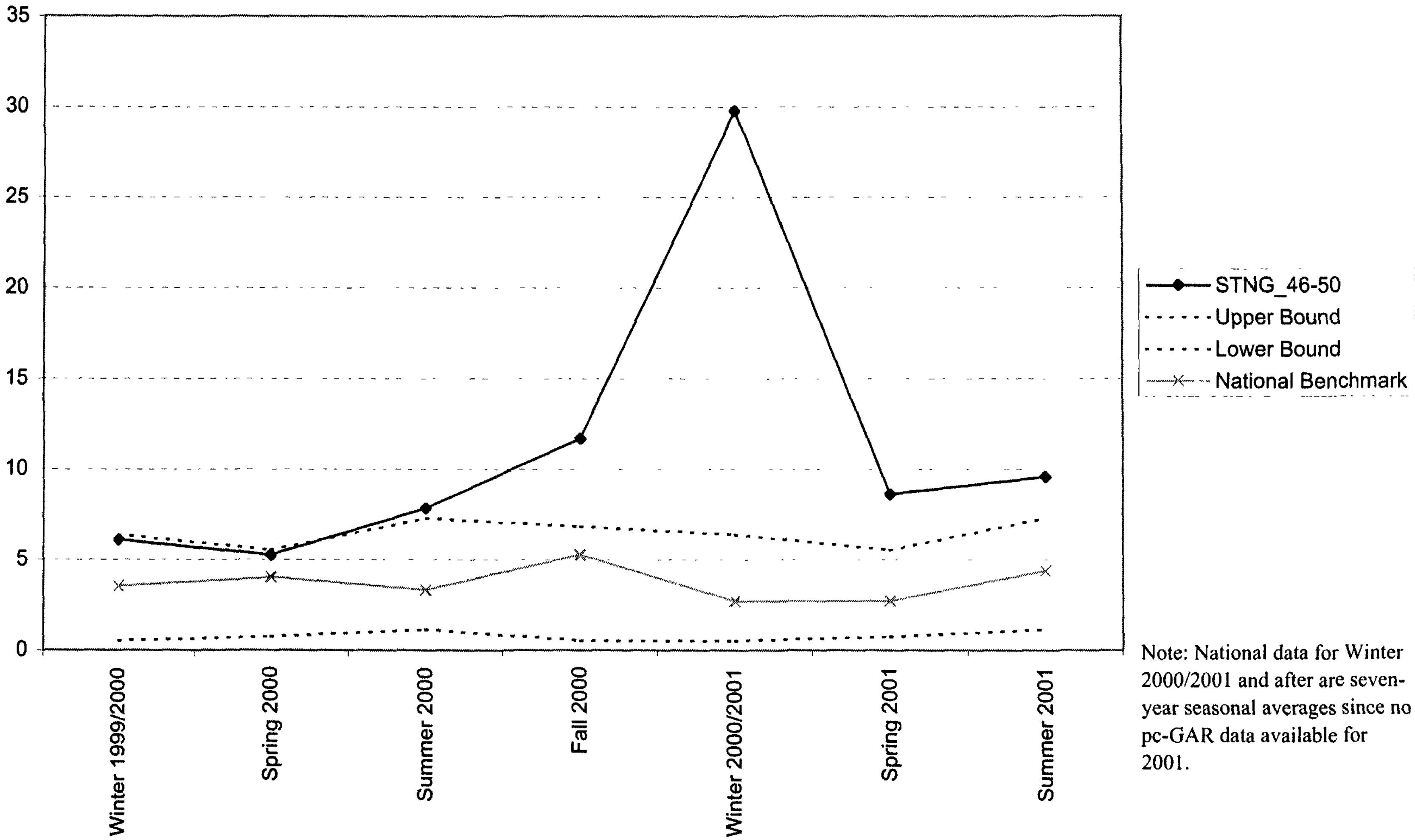
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

**Appendix PQH-F, Figure 9:
EFORP Over Time - California vs National Seasonal Average**



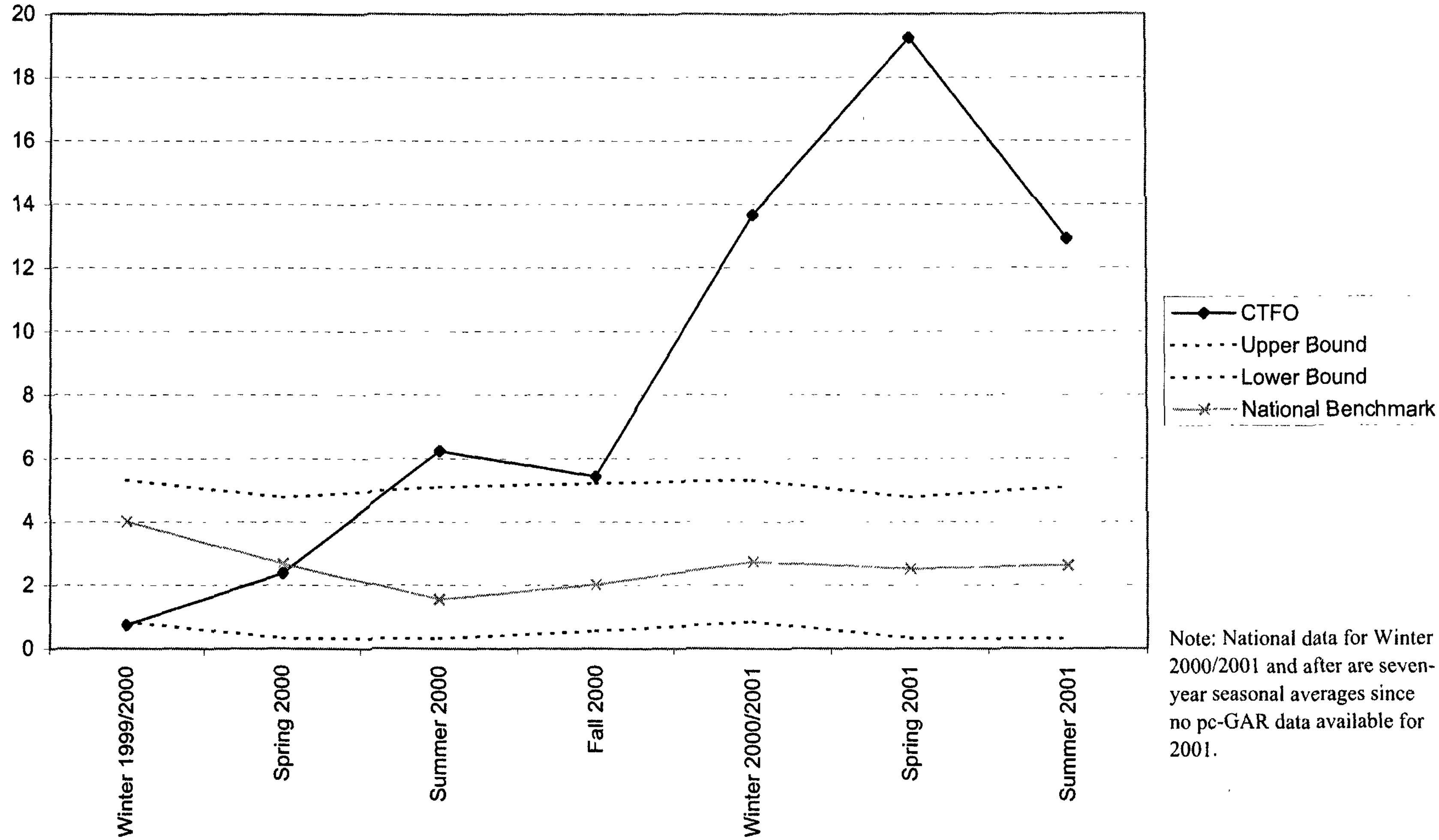
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

Appendix PQH-F, Figure 10:
EFORP Over Time - California vs National Seasonal Average



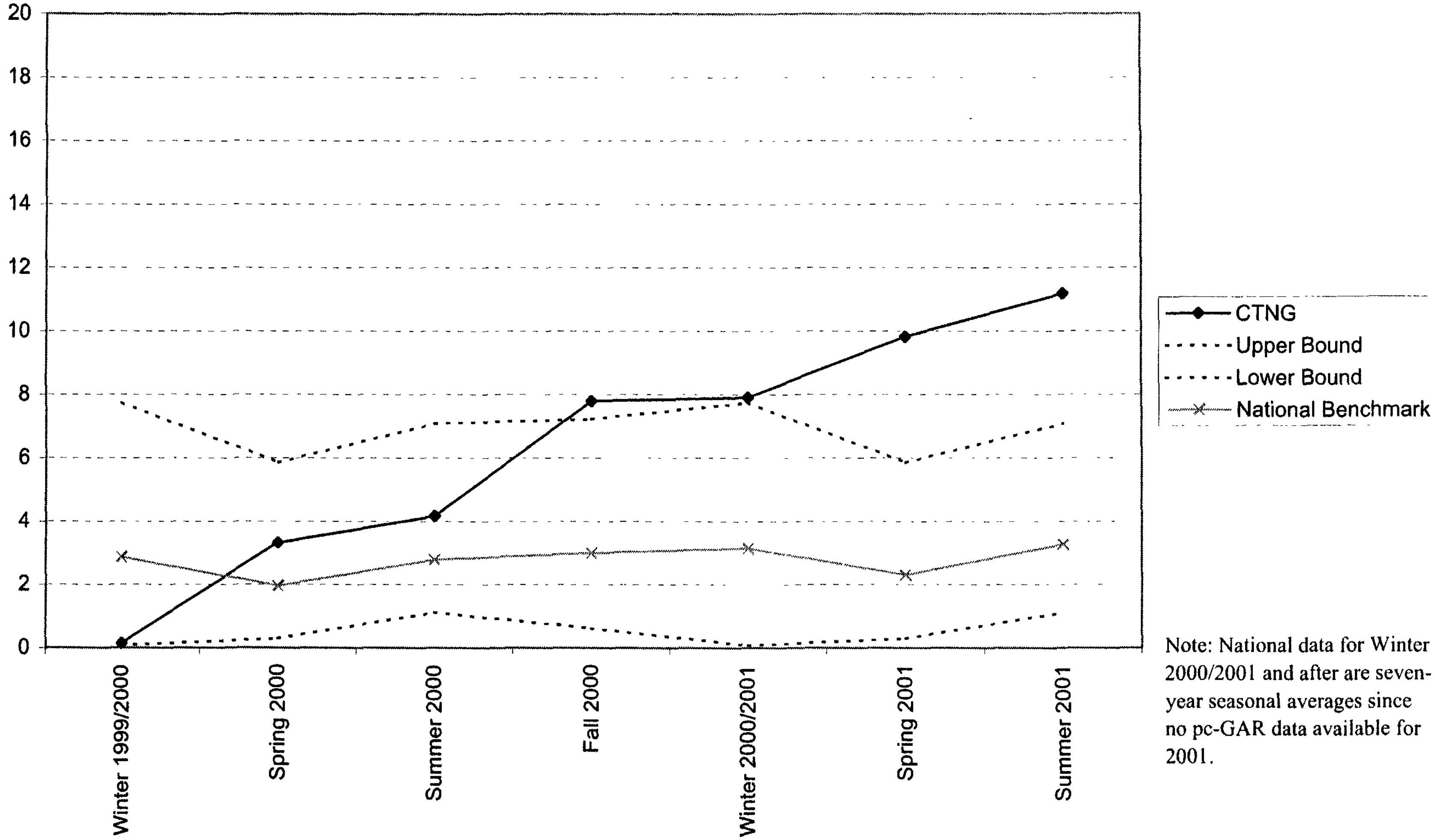
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

**Appendix PQH-F, Figure 11:
Capacity-Weighted Average EFORP over Time
California vs National Seasonal Average**



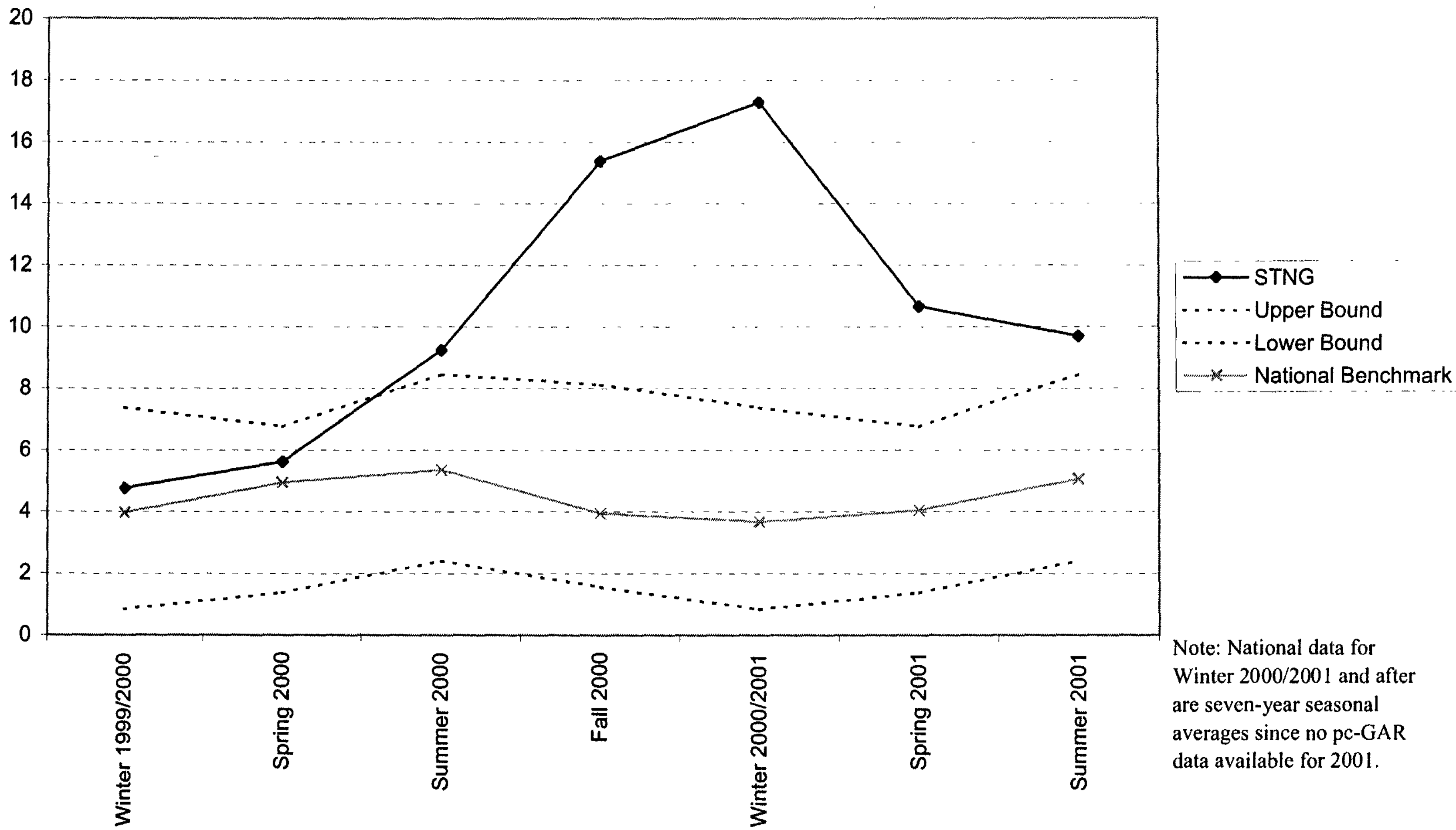
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

Appendix PQH-F, Figure 12:
Capacity-Weighted Average EFORP over Time
California vs National Seasonal Average



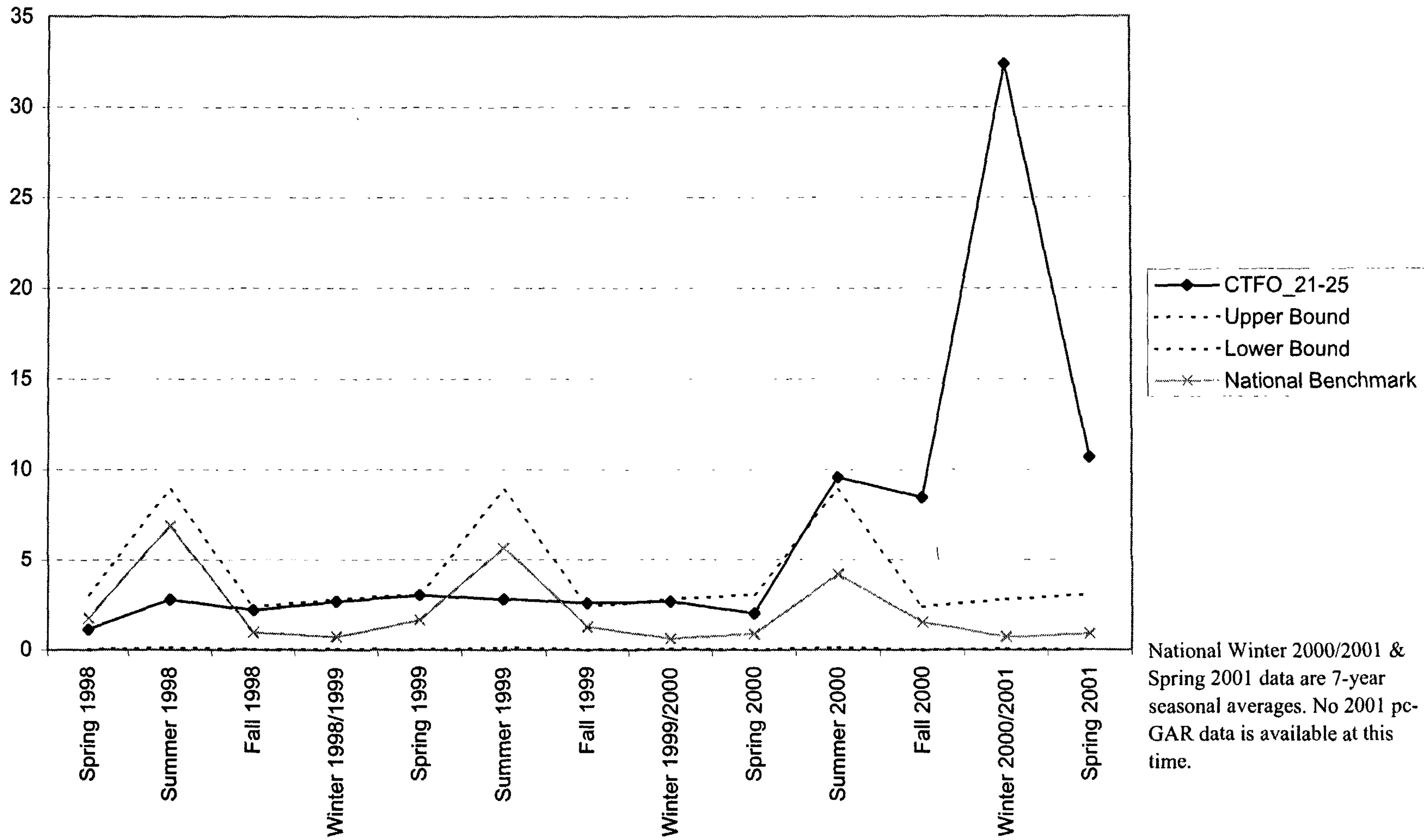
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

**Appendix PQH-F, Figure 13:
Capacity-Weighted Average EFORP over Time
California vs National Seasonal Average**



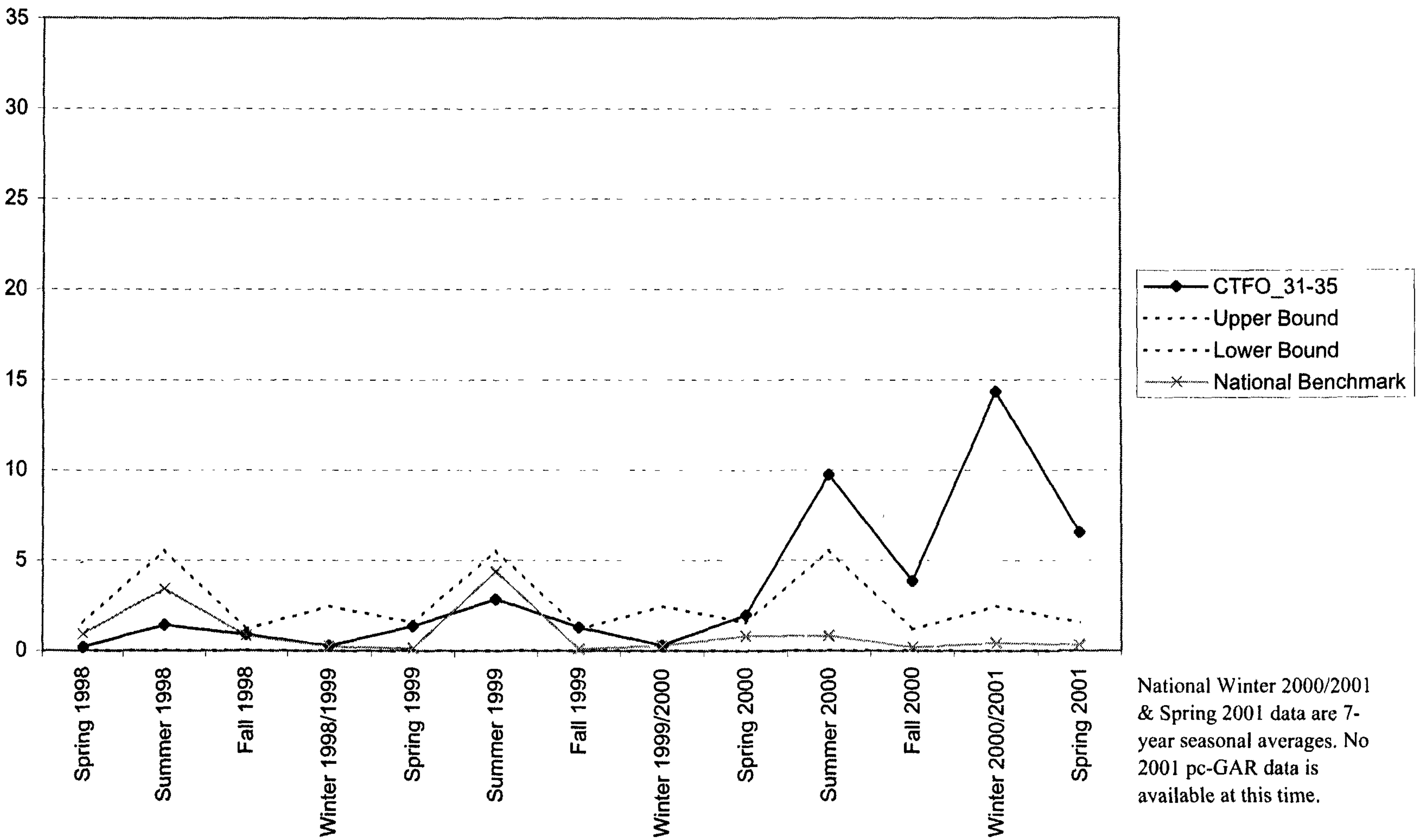
Note: National data for Winter 2000/2001 and after are seven-year seasonal averages since no pc-GAR data available for 2001.

Appendix PQH-F, Figure 14:
Capacity Factor over Time - California vs National Seasonal Average



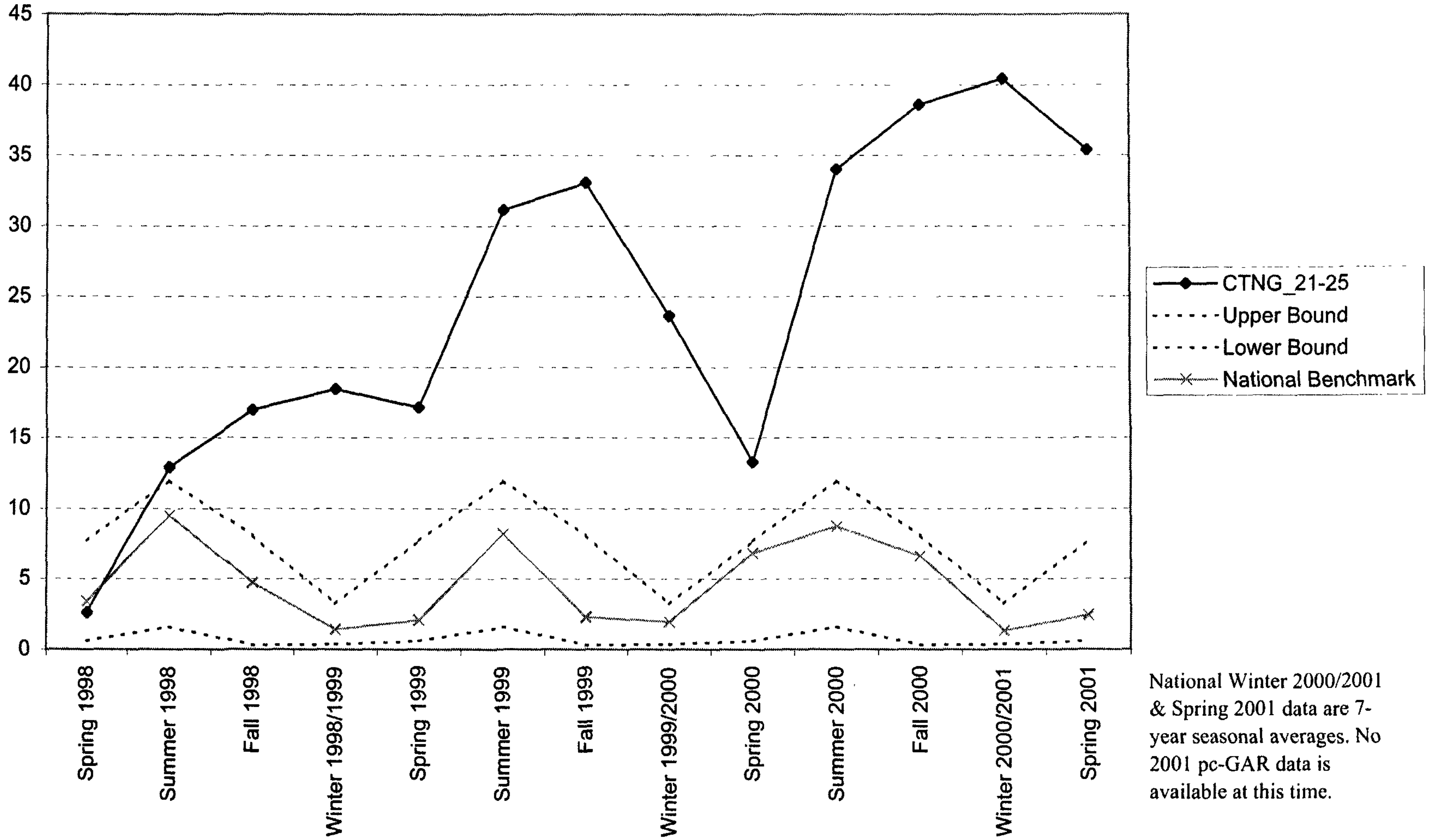
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 15:
Capacity Factor over Time - California vs National Seasonal Average



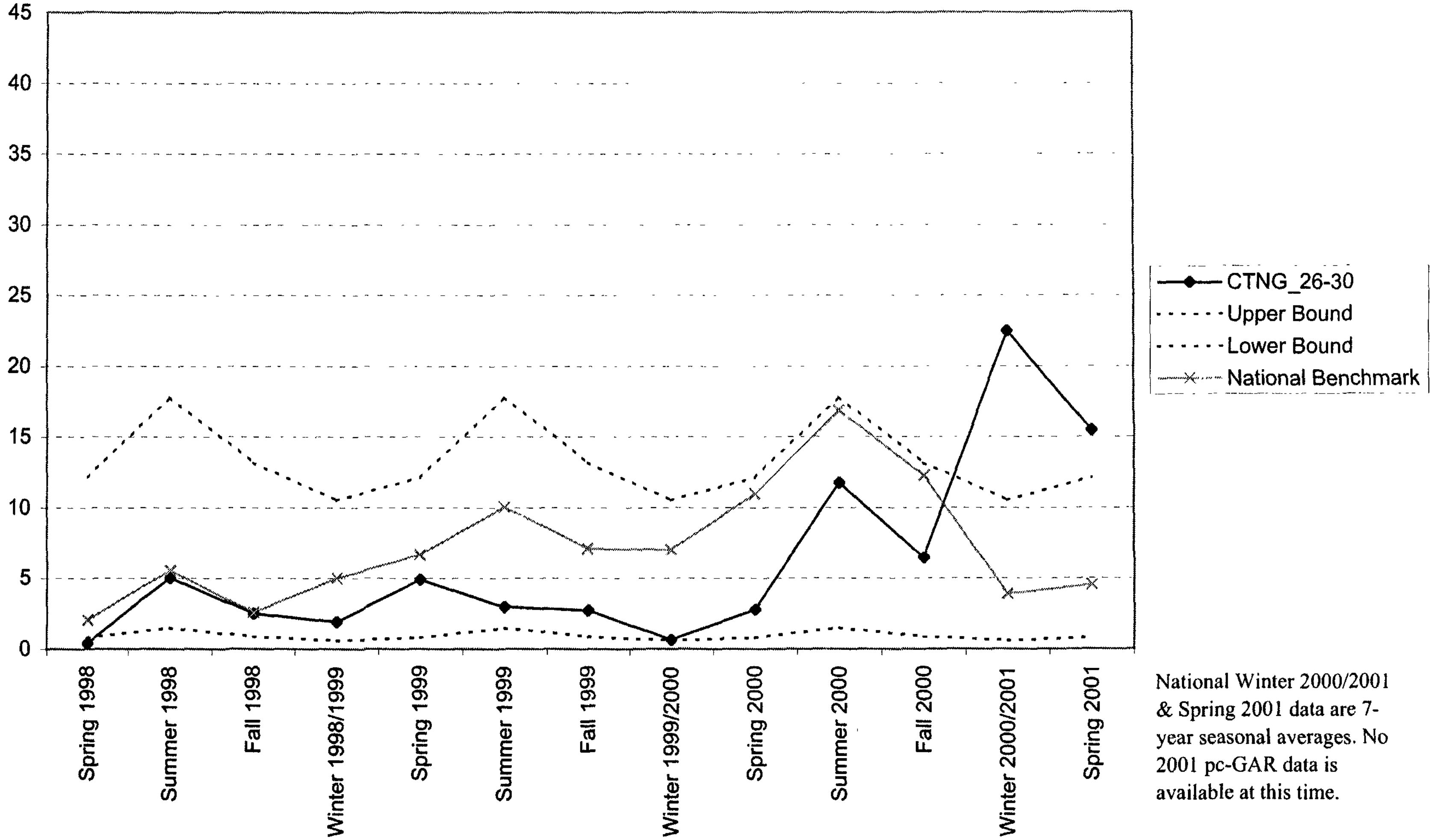
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 16:
Capacity Factor over Time - California vs National Seasonal Average



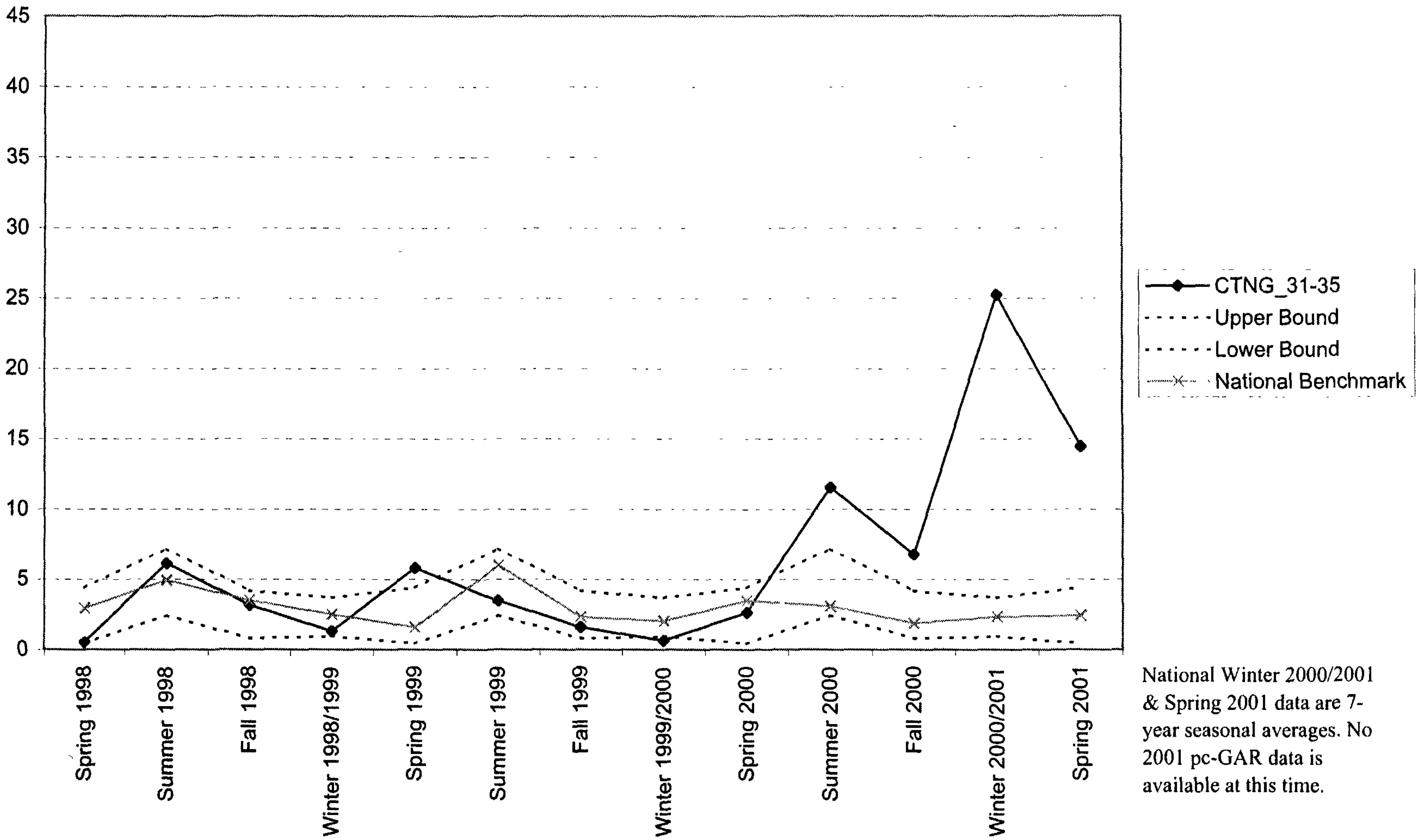
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

**Appendix PQH-F, Figure 17:
Capacity Factor over Time - California vs National Seasonal Average**



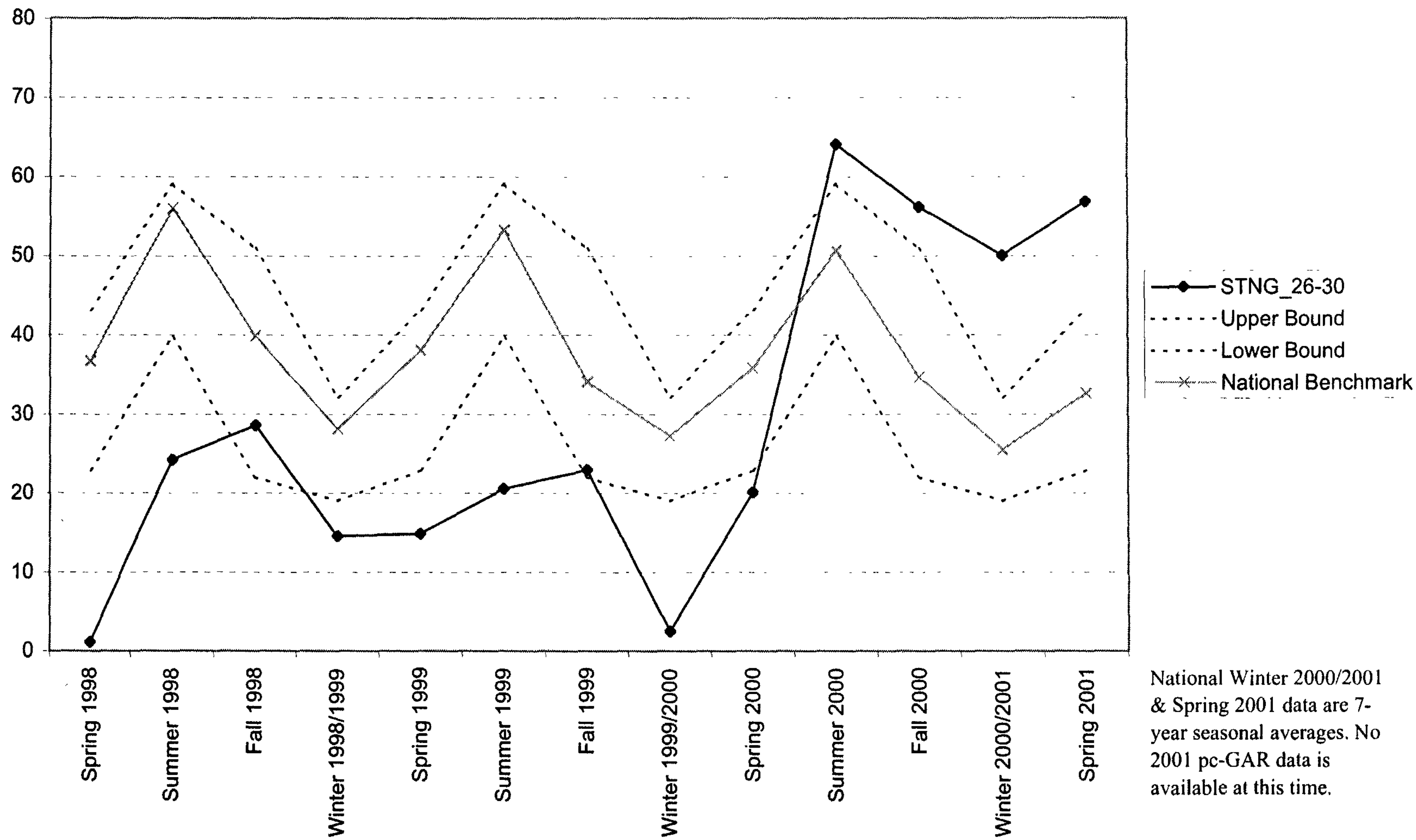
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 18:
Capacity Factor over Time - California vs National Seasonal Average



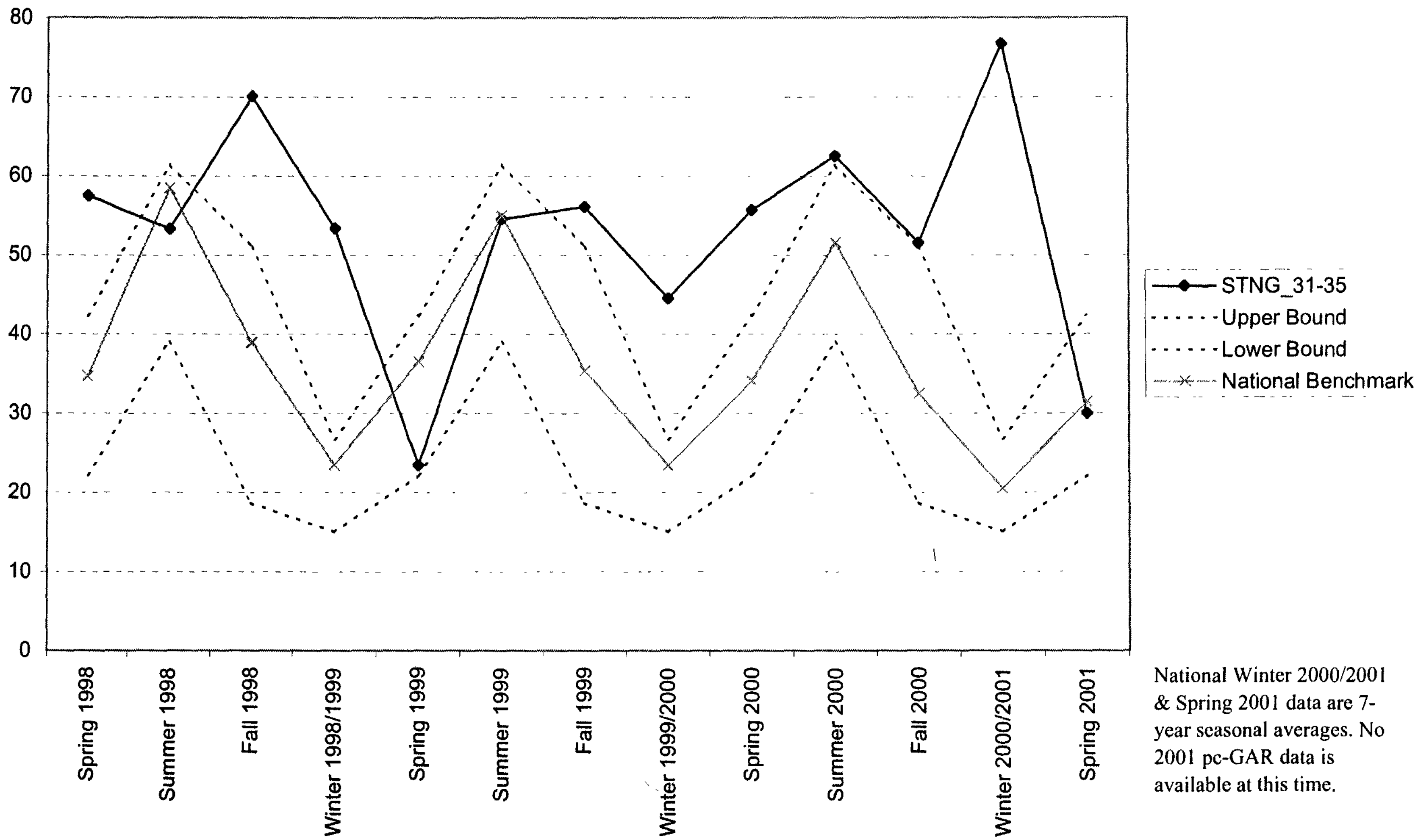
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 19:
Capacity Factor over Time - California vs National Seasonal Average



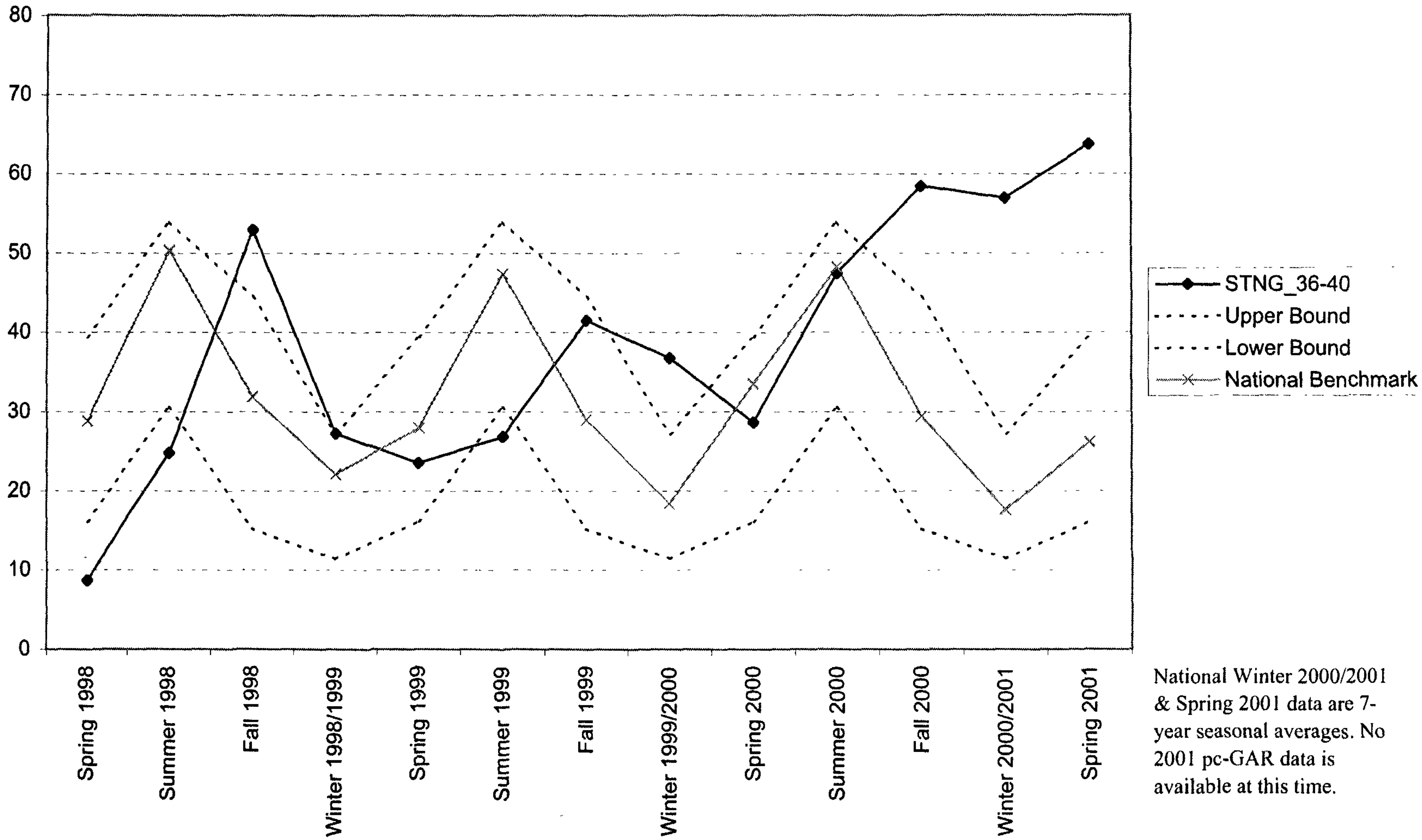
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 20:
Capacity Factor over Time - California vs National Seasonal Average



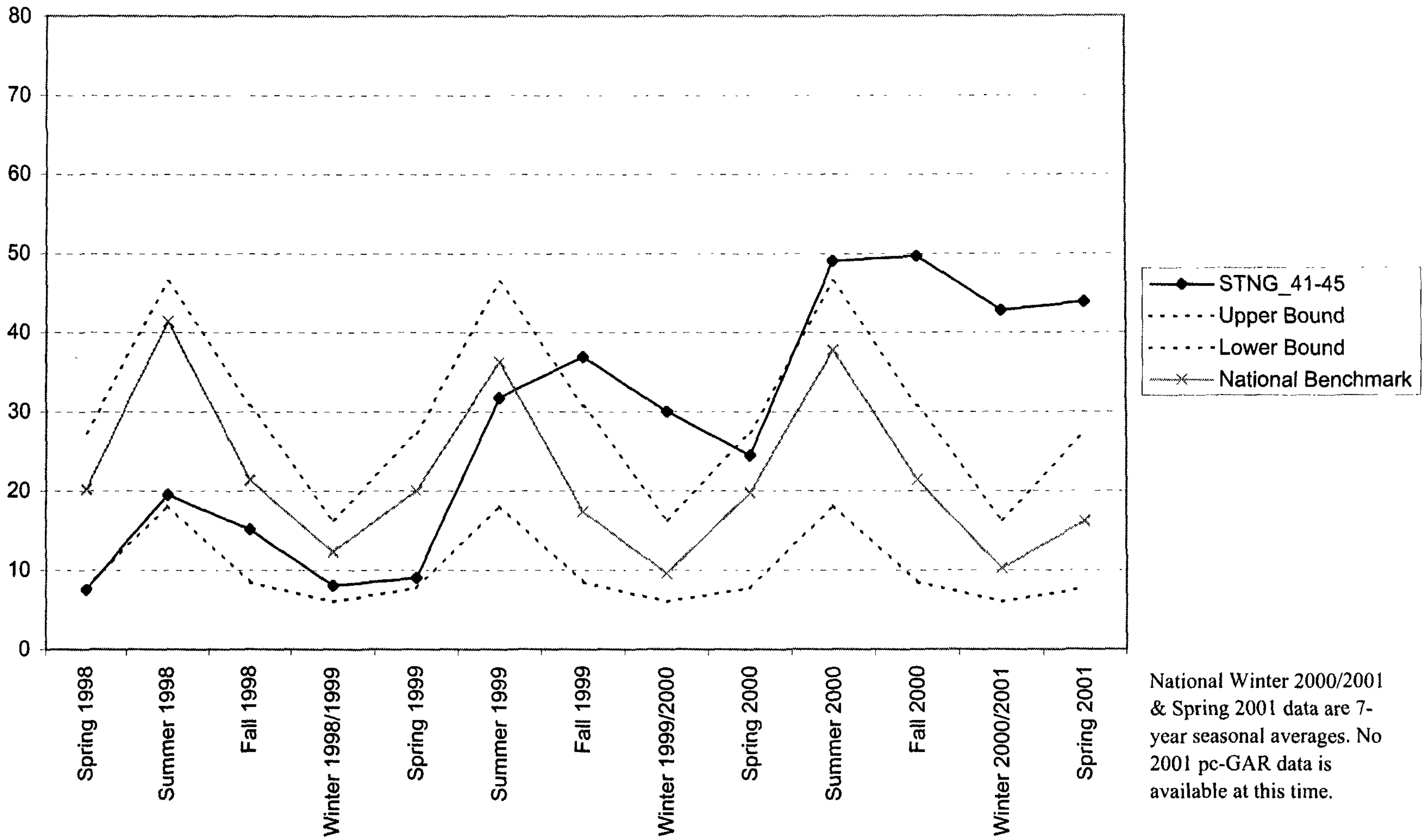
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 21:
Capacity Factor over Time - California vs National Seasonal Average



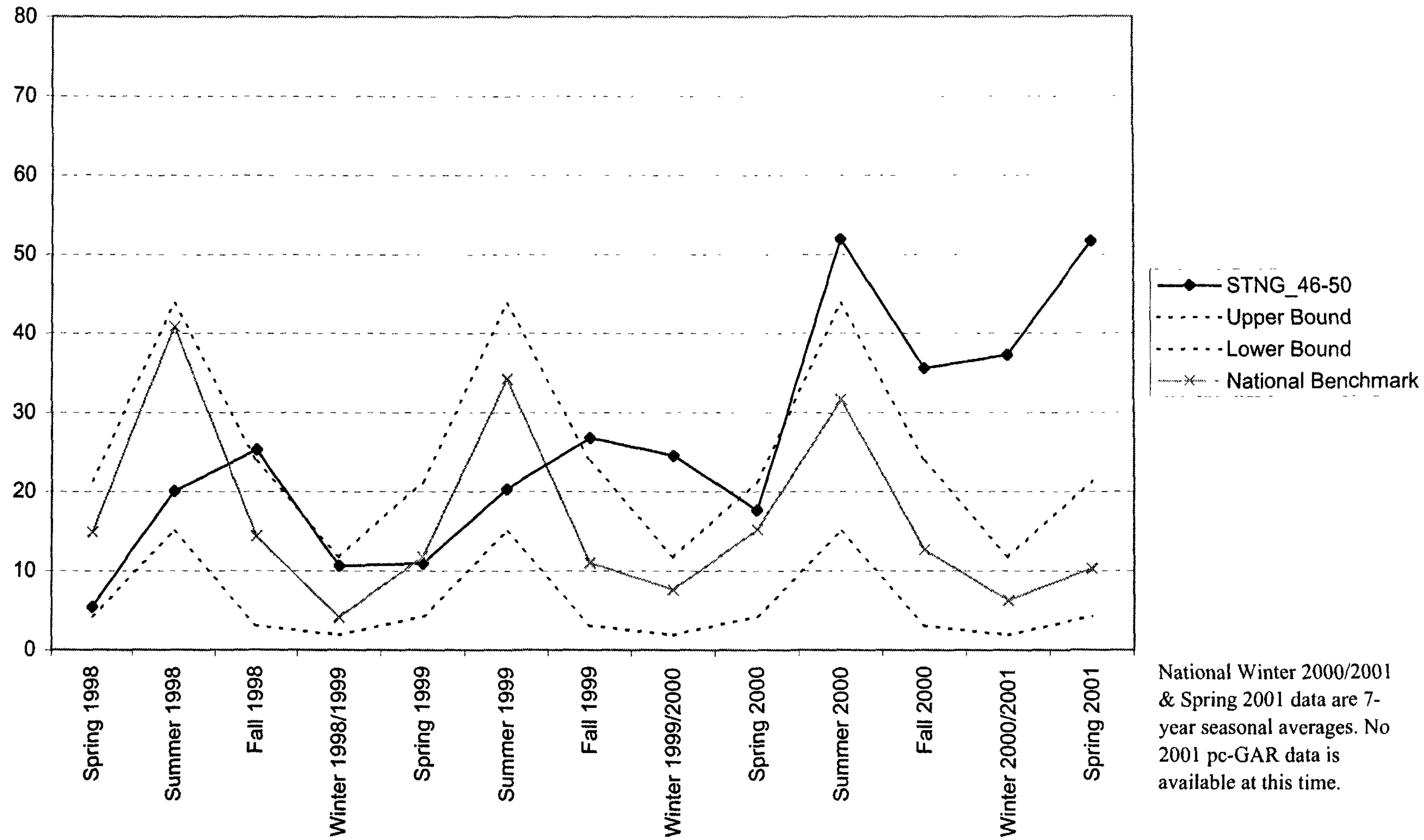
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 22:
Capacity Factor over Time - California vs National Seasonal Average



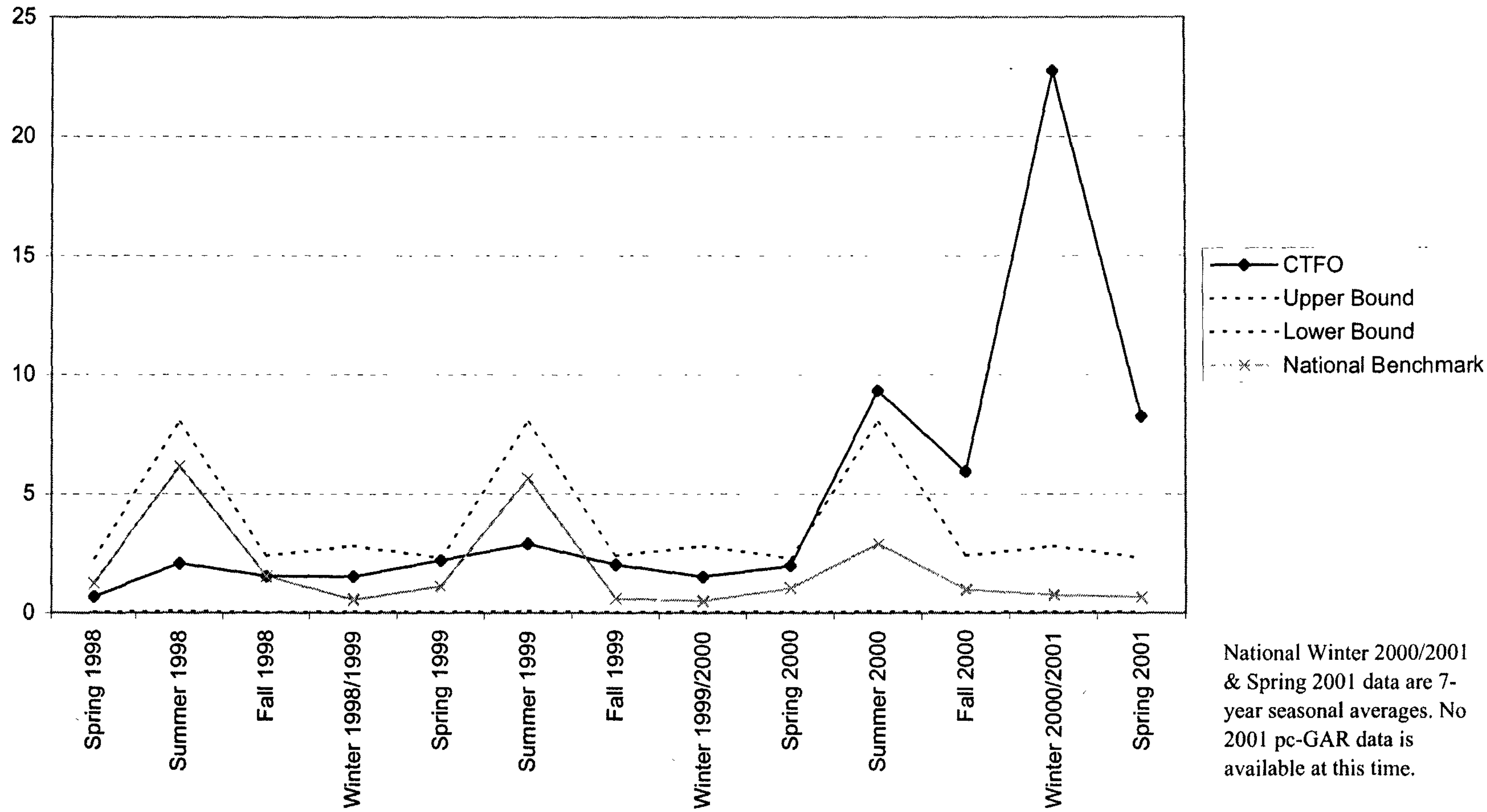
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 23:
Capacity Factor over Time - California vs National Seasonal Average



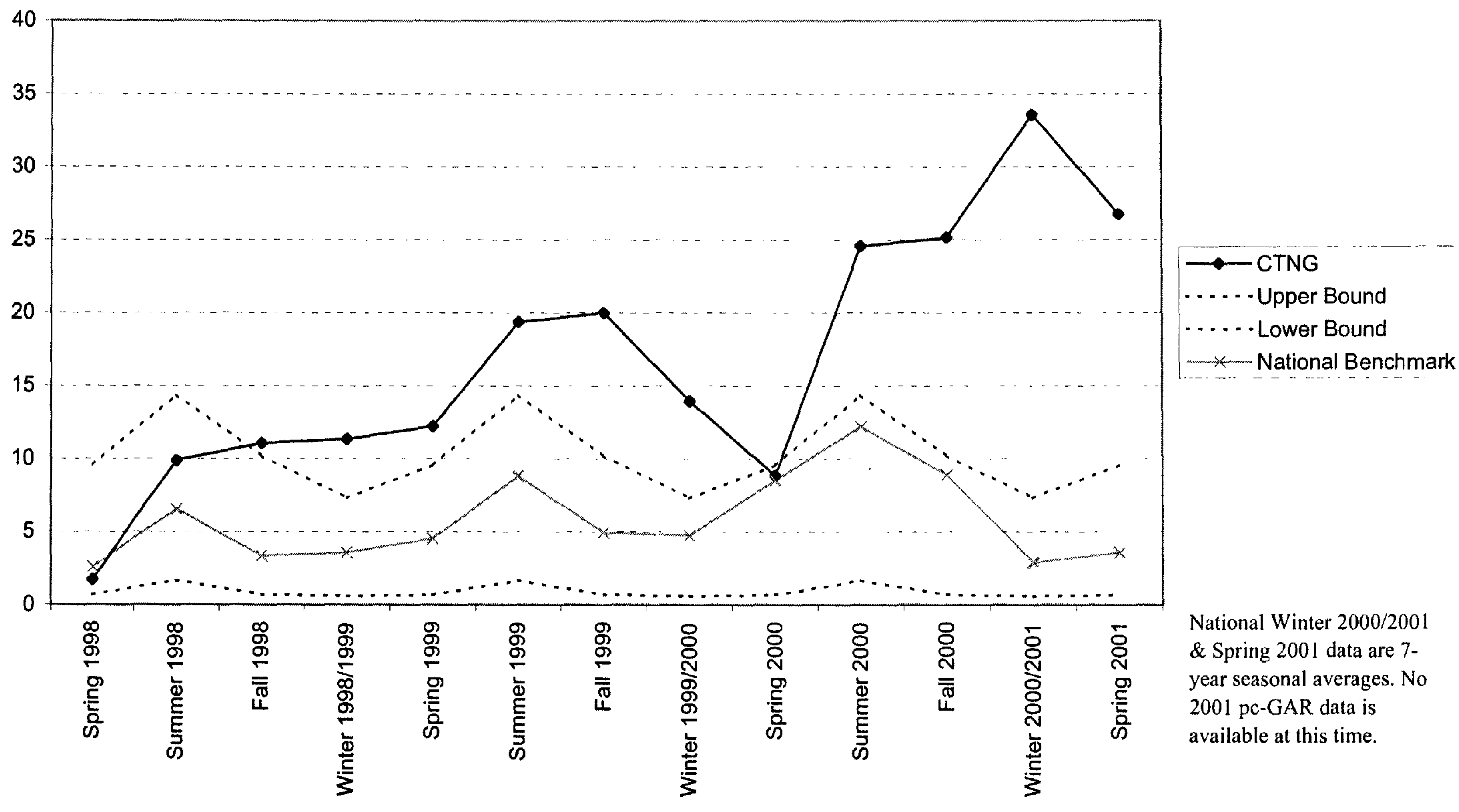
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 24:
Capacity-Weighted Average Capacity Factor over Time
California vs National Seasonal Average



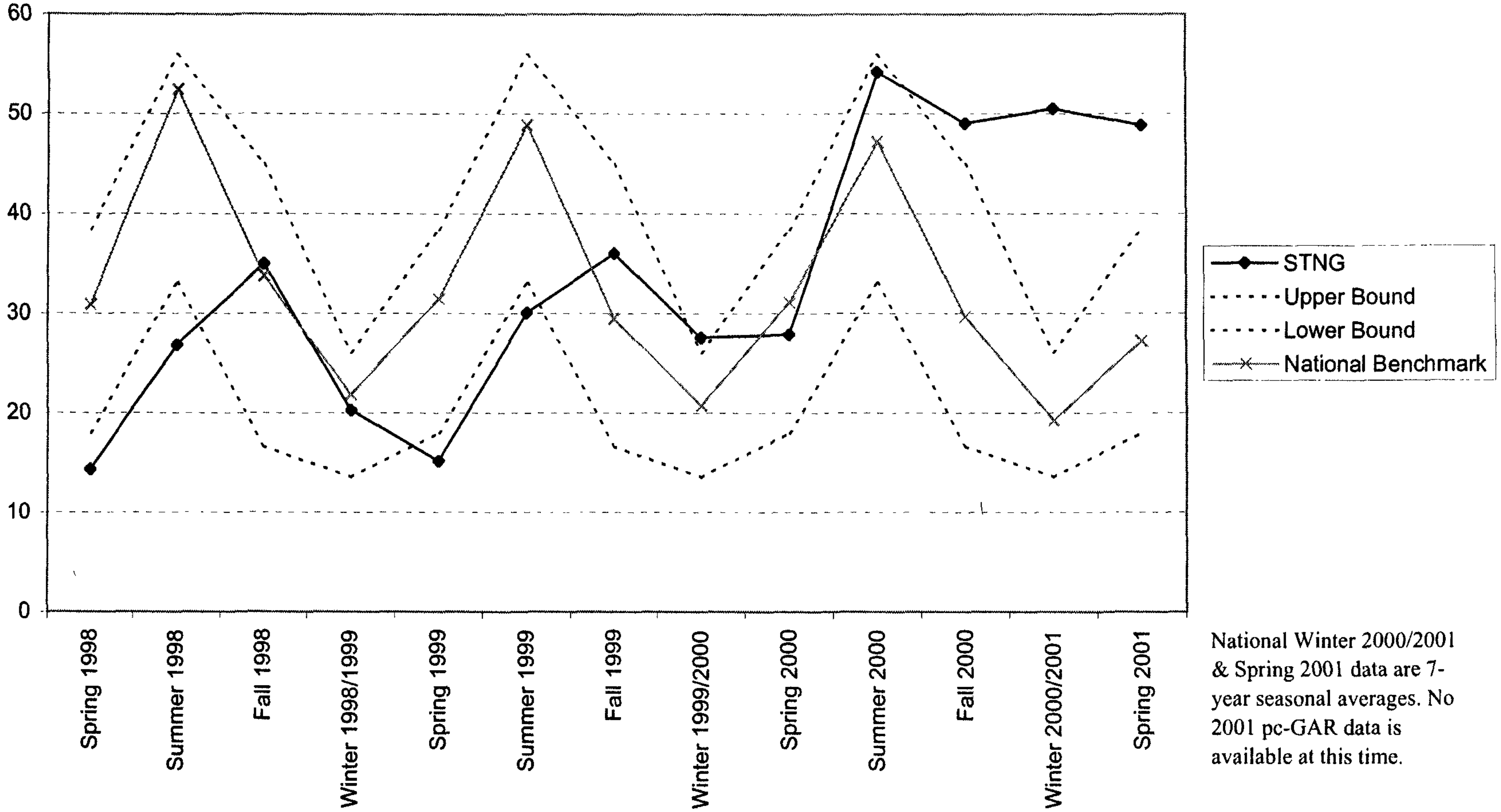
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 25:
Capacity-Weighted Average Capacity Factor over Time
California vs National Seasonal Average



National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Figure 26:
Capacity-Weighted Average Capacity Factor over Time
California vs National Seasonal Average



National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Table 1:
Comparison of Unit Sizes and Number of Units Across Technology and Age Groups California vs. National Benchmark

	Technology	Number of Units	Sum of Capacity	Average Capacity
CA Units	STNG	42	12,937	308
	CTNG	28	1,196	43
	CTFO	11	654	59
	CTFO_21-25	7	344	49
	CTFO_26-30	1	56	56
	CTFO_31-35	3	254	85
	CTNG_21-25	11	692	63
	CTNG_26-30	5	205	41
	CTNG_31-35	12	299	25
	STNG_26-30	3	2,157	719
	STNG_31-35	5	2,126	425
	STNG_36-40	8	2,086	261
	STNG_41-45	15	3,406	227
	STNG_46-50	11	3,163	288

	Technology	Number of Units	Sum of Capacity	Average Capacity
National	STNG	298	61,638	207
	CTNG	187	6,347	34
	CTFO	234	7,564	32
	CTFO_21-25	21	1,046	50
	CTFO_26-30	136	5,094	37
	CTFO_31-35	77	1,425	19
	CTNG_21-25	29	1,761	61
	CTNG_26-30	100	3,481	35
	CTNG_31-35	58	1,105	19
	STNG_26-30	55	22,112	402
	STNG_31-35	49	16,118	329
	STNG_36-40	55	9,747	177
	STNG_41-45	77	9,225	120
	STNG_46-50	62	4,435	72

Notes:
National Average Capacity is seven-year average (1994-2000).

Sources:
National: pc-GAR database.
California: Capacity Worksheet.

Appendix PQH-F, Table 2:
California Group Average Seasonal Equivalent Forced Outage Rate Proxy
By Technology and Age - Winter 1999/2000 through Summer 2001

Technology	Age Bracket	Season						
		Winter 1999/2000	Spring 2000	Summer 2000	Fall 2000	Winter 2000/2001	Spring 2001	Summer 2001
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTFO	21-25	1.30	0.26	11.06	6.39	12.97	25.26	24.49
CTFO	26-30	.	.	.	0.00	54.40	44.34	0.00
CTFO	31-35	0.14	5.73	1.04	5.30	5.59	5.54	0.10
CTNG	21-25	0.23	5.07	3.98	2.93	5.77	7.79	18.39
CTNG	26-30	0.00	0.17	3.63	31.46	16.05	12.62	0.10
CTNG	31-35	0.03	1.42	4.95	2.81	7.20	12.57	2.08
STNG	26-30	0.70	2.42	5.76	13.85	12.73	20.65	7.21
STNG	31-35	8.15	7.78	11.08	16.68	16.90	4.66	9.98
STNG	36-40	4.01	3.11	9.16	13.01	6.15	3.15	2.80
STNG	41-45	4.41	8.18	11.65	20.40	15.61	14.58	15.46
STNG	46-50	6.09	5.24	7.84	11.67	29.79	8.60	9.57

Source:
Generator Event Data.

Appendix PQH-F, Table 3:
National Benchmark Average Seasonal Equivalent Forced Outage Rate Proxy
By Technology and Age - Winter 1999/2000 through Summer 2001

Technology	Age Bracket	Season						
		Winter 1999/2000	Spring 2000	Summer 2000	Fall 2000	Winter 2000/2001	Spring 2001	Summer 2001
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTFO	21-25	2.05	0.10	2.51	0.16	0.59	0.48	1.18
CTFO	26-30	5.19	3.53	1.33	2.60	3.17	2.73	2.75
CTFO	31-35	1.17	1.38	1.54	1.24	2.63	3.16	3.17
CTNG	21-25	2.97	1.68	2.92	6.54	2.44	1.10	1.74
CTNG	26-30	3.06	2.19	2.96	1.47	3.46	2.63	4.16
CTNG	31-35	1.96	1.59	1.94	2.06	3.13	3.10	2.80
STNG	26-30	3.66	5.50	6.24	3.36	3.44	4.44	5.19
STNG	31-35	4.55	4.47	5.76	4.53	4.24	4.25	5.24
STNG	36-40	1.56	3.16	4.40	4.18	2.77	3.21	4.68
STNG	41-45	6.41	6.72	4.47	3.45	4.56	4.23	5.16
STNG	46-50	3.52	4.02	3.32	5.26	2.69	2.69	4.37

Source:
NERC pc-GAR database.

Appendix PQH-F, Table 4A:
EFORP Key Statistics by Season 1994 - 2000
CTFO

Winter

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
CTFO_21-25	0.59	0.13	0.98	0.00	3.28	-1.37	2.55	0.00	2.55
CTFO_26-30	3.17	3.24	1.28	1.16	5.79	0.60	5.73	1.16	5.73
CTFO_31-35	2.63	2.34	1.61	0.31	6.82	-0.58	5.85	0.31	5.85

Spring

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
CTFO_21-25	0.48	0.27	0.85	0.00	3.35	-1.23	2.18	0.00	2.18
CTFO_26-30	2.73	2.68	1.16	0.44	4.78	0.41	5.05	0.44	4.78
CTFO_31-35	3.16	2.81	1.72	0.18	7.95	-0.27	6.60	0.18	6.60

Summer

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
CTFO_21-25	1.18	0.97	1.09	0.02	4.40	-1.00	3.36	0.02	3.36
CTFO_26-30	2.75	2.29	1.62	0.38	5.26	-0.48	5.99	0.38	5.26
CTFO_31-35	3.17	3.25	1.66	0.37	5.82	-0.16	6.50	0.37	5.82

Fall

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
CTFO_21-25	0.74	0.17	1.52	0.00	5.63	-2.31	3.79	0.00	3.79
CTFO_26-30	2.58	2.22	1.48	0.80	6.37	-0.39	5.54	0.80	5.54
CTFO_31-35	2.12	1.49	1.48	0.11	6.39	-0.85	5.08	0.11	5.08

Source:
NERC pc-GAR database

Notes:
[6] = [1] - 2 * [3]
[7] = [1] + 2 * [3]
[8]: Higher value of [4] and [6]
[9]: Lower value of [5] and [7]

Appendix PQH-F, Table 4B:
EFORP Key Statistics by Season 1994 - 2000
CTNG

Winter

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTNG_21-25	2.44	2.18	2.08	0.02	8.86	-1.73	6.60	0.02	6.60
CTNG_26-30	3.46	2.69	2.26	0.08	8.68	-1.06	7.99	0.08	7.99
CTNG_31-35	3.13	1.76	2.78	0.13	11.80	-2.42	8.68	0.13	8.68

Spring

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTNG_21-25	1.10	0.89	1.27	0.00	5.26	-1.43	3.63	0.00	3.63
CTNG_26-30	2.63	2.12	1.88	0.49	6.98	-1.13	6.39	0.49	6.39
CTNG_31-35	3.10	2.92	2.26	0.13	7.85	-1.43	7.63	0.13	7.63

Summer

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTNG_21-25	1.74	1.13	1.52	0.11	4.70	-1.30	4.77	0.11	4.70
CTNG_26-30	4.16	3.12	2.28	1.83	9.90	-0.40	8.72	1.83	8.72
CTNG_31-35	2.80	2.53	1.43	0.42	5.93	-0.06	5.66	0.42	5.66

Fall

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTNG_21-25	3.12	3.28	2.83	0.02	9.94	-2.54	8.78	0.02	8.78
CTNG_26-30	3.19	2.94	1.91	0.63	7.30	-0.63	7.02	0.63	7.02
CTNG_31-35	2.98	2.59	1.18	1.48	5.29	0.63	5.34	1.48	5.29

Source:
NERC pc-GAR database

Notes:
[6] = [1] - 2 * [3]
[7] = [1] + 2 * [3]
Higher value of [4] and [6]
Lower value of [5] and [7]

Appendix PQH-F, Table 4C:
EFORP Key Statistics by Season 1994 - 2000
STNG

Winter

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
STNG_26-30	3.44	3.19	1.53	1.05	6.79	0.37	6.50	1.05	6.50
STNG_31-35	4.24	3.34	2.41	0.50	9.88	-0.58	9.06	0.50	9.06
STNG_36-40	2.77	3.22	1.71	0.38	6.27	-0.65	6.18	0.38	6.18
STNG_41-45	4.56	4.74	1.83	1.48	8.49	0.90	8.22	1.48	8.22
STNG_46-50	2.69	2.77	1.84	0.53	6.57	-1.00	6.38	0.53	6.38

Spring

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
STNG_26-30	4.44	4.58	1.30	1.78	6.59	1.83	7.04	1.83	6.59
STNG_31-35	4.25	4.32	1.55	1.29	7.73	1.15	7.35	1.29	7.35
STNG_36-40	3.21	3.13	1.48	0.67	7.37	0.25	6.16	0.67	6.16
STNG_41-45	4.23	4.11	1.55	1.47	7.86	1.12	7.34	1.47	7.34
STNG_46-50	2.69	2.29	1.42	0.75	5.72	-0.14	5.52	0.75	5.52

Summer

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
STNG_26-30	5.19	5.38	1.57	2.78	8.46	2.04	8.33	2.78	8.33
STNG_31-35	5.24	5.09	1.66	2.57	9.55	1.93	8.55	2.57	8.55
STNG_36-40	4.68	4.51	1.24	3.00	8.69	2.20	7.16	3.00	7.16
STNG_41-45	5.16	4.73	2.67	1.16	12.38	-0.19	10.50	1.16	10.50
STNG_46-50	4.37	4.79	2.01	1.15	7.27	0.35	8.40	1.15	7.27

Fall

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
STNG_26-30	4.62	4.31	1.93	1.57	8.83	0.76	8.47	1.57	8.47
STNG_31-35	4.80	4.61	2.01	1.67	9.10	0.78	8.83	1.67	8.83
STNG_36-40	4.07	4.26	1.33	1.31	6.97	1.41	6.72	1.41	6.72
STNG_41-45	5.38	5.66	2.03	1.96	8.09	1.32	9.45	1.96	8.09
STNG_46-50	3.67	3.66	2.09	0.53	6.81	-0.50	7.85	0.53	6.81

Source
NERC pc-GAR database

Notes.
[6] = [1] - 2 * [3]
[7] = [1] + 2 * [3]
[8]. Higher value of [4] and [6]
[9] Lower value of [5] and [7]

Appendix PQH-F, Table 5:
California Group Average Seasonal Net Capacity Factor
By Technology and Age - Spring 1998 through Spring 2001

Technology	Age Bracket	Season												
		Spring 1998	Summer 1998	Fall 1998	Winter 1998/1999	Spring 1999	Summer 1999	Fall 1999	Winter 1999/2000	Spring 2000	Summer 2000	Fall 2000	Winter 2000/2001	Spring 2001
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
CTFO	21-25	1.13	2.78	2.19	2.67	3.02	2.81	2.59	2.66	2.02	9.55	8.45	32.37	10.65
CTFO	26-30	0.01	0.64	0.48	0.12	0.98	3.68	1.74	0.08	1.61	6.17	0.00	1.91	1.17
CTFO	31-35	0.20	1.42	0.89	0.27	1.36	2.85	1.31	0.30	1.98	9.73	3.84	14.34	6.54
CTNG	21-25	2.62	12.92	16.97	18.45	17.15	31.11	33.04	23.62	13.30	34.00	38.59	40.44	35.38
CTNG	26-30	0.40	5.02	2.49	1.90	4.89	2.94	2.70	0.65	2.77	11.75	6.44	22.47	15.47
CTNG	31-35	0.51	6.12	3.17	1.30	5.80	3.47	1.58	0.64	2.64	11.55	6.78	25.24	14.45
STNG	26-30	1.16	24.23	28.57	14.53	14.84	20.56	22.93	2.47	20.10	64.10	56.17	50.05	56.82
STNG	31-35	57.50	53.29	70.04	53.39	23.40	54.51	56.11	44.53	55.63	62.54	51.52	76.72	29.99
STNG	36-40	8.67	24.76	52.88	27.24	23.52	26.84	41.52	36.78	28.64	47.43	58.44	56.93	63.65
STNG	41-45	7.55	19.51	15.11	8.03	9.01	31.76	36.92	29.98	24.46	49.01	49.65	42.82	43.86
STNG	46-50	5.40	20.04	25.26	10.59	10.94	20.29	26.80	24.55	17.65	51.87	35.58	37.25	51.67

Source:
CAISO CD 1534.

Appendix PQH-F, Table 6:
National Benchmark Average Seasonal Net Capacity Factor
By Technology and Age - Spring 1998 through Spring 2001

Technology	Age Bracket	Season												
		Spring 1998	Summer 1998	Fall 1998	Winter 1998/1999	Spring 1999	Summer 1999	Fall 1999	Winter 1999/2000	Spring 2000	Summer 2000	Fall 2000	Winter 2000/2001	Spring 2001
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
CTFO	21-25	1.75	6.85	0.94	0.71	1.65	5.66	1.27	0.60	0.88	4.16	1.52	0.70	0.87
CTFO	26-30	1.20	6.77	1.84	0.58	1.27	5.99	0.60	0.53	1.12	3.22	1.08	0.84	0.70
CTFO	31-35	0.91	3.39	0.83	0.22	0.12	4.36	0.09	0.28	0.80	0.82	0.19	0.43	0.30
CTNG	21-25	3.39	9.47	4.72	1.41	2.07	8.16	2.26	1.94	6.83	8.70	6.58	1.32	2.41
CTNG	26-30	2.05	5.53	2.57	4.98	6.65	10.03	7.08	6.99	10.94	16.83	12.25	3.86	4.51
CTNG	31-35	2.93	4.91	3.48	2.48	1.56	5.97	2.31	2.03	3.46	3.06	1.86	2.32	2.41
STNG	26-30	36.66	55.97	39.80	28.12	38.01	53.20	34.06	27.20	35.79	50.59	34.61	25.51	32.56
STNG	31-35	34.66	58.41	38.92	23.43	36.48	54.93	35.34	23.38	34.01	51.53	32.44	20.43	31.39
STNG	36-40	28.85	50.28	31.83	22.11	27.92	47.34	28.93	18.39	33.48	48.21	29.32	17.62	26.12
STNG	41-45	20.21	41.37	21.31	12.29	19.98	36.28	17.36	9.56	19.69	37.67	21.38	10.18	16.16
STNG	46-50	14.88	40.84	14.35	4.10	11.74	34.22	10.99	7.60	15.18	31.64	12.60	6.23	10.32

Source:
NERC pc-GAR database.

Note:
National Winter 2000/2001 & Spring 2001 data are 7-year seasonal averages. No 2001 pc-GAR data is available at this time.

Appendix PQH-F, Table 7A:
NCF Key Statistics by Season 1994 - 2000
CTFO

Winter

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
CTFO_21-25	0.70	0.30	1 05	0 04	4 81	-1 40	2 79	0 04	2 79
CTFO_26-30	0.84	0 42	1 03	0 07	3 94	-1 23	2 91	0 07	2 91
CTFO_31-35	0.43	0 13	1 02	0 00	4 75	-1 60	2 46	0 00	2 46

Spring

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
CTFO_21-25	0.87	0 55	1 10	0 03	4 01	-1 33	3 07	0 03	3 07
CTFO_26-30	0 70	0 40	0 83	0.05	2 79	-0 95	2 35	0 05	2 35
CTFO_31-35	0 30	0.05	0 62	0 00	2.28	-0.94	1 55	0 00	1 55

Summer

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
CTFO_21-25	3 17	2 00	2 84	0 13	9 04	-2 50	8 84	0 13	8 84
CTFO_26-30	3 22	2 23	2 63	0 09	9.04	-2 04	8 48	0.09	8 48
CTFO_31-35	1 89	1.05	1.83	0 01	7 62	-1.78	5 55	0 01	5 55

Fall

	Average [1]	Median [2]	Stdev [3]	Min [4]	Max [5]	Avg - 2*Stdev [6]	Avg + 2*Stdev [7]	Lower Bound [8]	Upper Bound [9]
CTFO_21-25	0 71	0.34	0 84	0 01	3 01	-0 97	2 39	0.01	2 39
CTFO_26-30	0 78	0 50	0 98	0 03	4 51	-1 17	2 74	0 03	2 74
CTFO_31-35	0.25	0 04	0 46	0 01	2.08	-0 68	1 17	0.01	1.17

Source:
NERC pc-GAR database

Notes.
[6] = [1] - 2 * [3]
[7] = [1] + 2 * [3]
[8]. Higher value of [4] and [6]
[9]: Lower value of [5] and [7]

Appendix PQH-F, Table 7B:
NCF Key Statistics by Season 1994 - 2000
CTNG

Winter

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTNG_21-25	1 32	0 98	0 95	0 36	4 11	-0 58	3 22	0 36	3 22
CTNG_26-30	3 86	3 79	3.33	0 61	12.78	-2 81	10 52	0 61	10 52
CTNG_31-35	2.32	2.41	0 68	0 45	3 76	0 95	3 69	0 95	3 69

Spring

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTNG_21-25	2.41	1 30	2.65	0 59	12 25	-2 89	7 71	0 59	7 71
CTNG_26-30	4.51	4.09	3 80	0 80	16 19	-3 10	12.12	0 80	12 12
CTNG_31-35	2 41	2 50	1 00	0 13	5 24	0 42	4 40	0 42	4 40

Summer

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTNG_21-25	5 94	4 60	3 35	1 58	11 97	-0 76	12 64	1 58	11 97
CTNG_26-30	7 42	6.29	5.19	1 47	20 23	-2 96	17 81	1 47	17 81
CTNG_31-35	4 02	3 69	1 59	2 43	8 89	0.85	7 19	2 43	7 19

Fall

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
CTNG_21-25	3 00	2 12	2 54	0.31	9.94	-2 07	8 07	0 31	8 07
CTNG_26-30	5.11	3 94	4 02	0.86	13 73	-2.94	13 15	0 86	13 15
CTNG_31-35	2 48	2.44	0.84	0.70	5 46	0 79	4 17	0 79	4 17

Source.
NERC pc-GAR database

Notes·
[6] = [1] - 2 * [3]
[7] = [1] + 2 * [3]
Higher value of [4] and [6]
Lower value of [5] and [7]

Appendix PQH-F, Table 7C:
NCF Key Statistics by Season 1994 - 2000
STNG

	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
Winter									
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
STNG_26-30	25.51	25.72	3.56	18.99	32.12	18.39	32.63	18.99	32.12
STNG_31-35	20.43	20.29	3.32	14.95	26.70	13.79	27.07	14.95	26.70
STNG_36-40	17.62	16.29	4.79	11.39	32.18	8.04	27.21	11.39	27.21
STNG_41-45	10.18	9.44	3.07	5.99	20.69	4.04	16.32	5.99	16.32
STNG_46-50	6.23	5.93	2.74	1.90	13.54	0.76	11.70	1.90	11.70
Spring									
	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
STNG_26-30	32.56	32.69	6.08	22.87	43.13	20.39	44.73	22.87	43.13
STNG_31-35	31.39	31.62	6.07	22.15	42.33	19.26	43.53	22.15	42.33
STNG_36-40	26.12	25.64	6.64	16.13	43.61	12.83	39.40	16.13	39.40
STNG_41-45	16.16	15.16	5.57	7.73	29.42	5.03	27.29	7.73	27.29
STNG_46-50	10.32	8.02	5.50	4.24	25.70	-0.68	21.32	4.24	21.32
Summer									
	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
STNG_26-30	50.38	51.82	5.33	39.33	59.05	39.72	61.04	39.72	59.05
STNG_31-35	50.25	50.16	6.10	38.95	61.35	38.05	62.45	38.95	61.35
STNG_36-40	43.62	42.53	6.58	28.88	53.90	30.47	56.77	30.47	53.90
STNG_41-45	31.55	29.87	7.82	18.14	46.45	15.91	47.20	18.14	46.45
STNG_46-50	27.57	23.97	9.21	14.91	43.80	9.16	45.98	14.91	43.80
Fall									
	Average	Median	Stdev	Min	Max	Avg - 2*Stdev	Avg + 2*Stdev	Lower Bound	Upper Bound
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
STNG_26-30	34.23	32.43	8.33	21.99	53.89	17.58	50.88	21.99	50.88
STNG_31-35	32.17	30.92	9.44	18.63	55.20	13.30	51.05	18.63	51.05
STNG_36-40	27.82	26.40	8.30	15.22	44.51	11.22	44.43	15.22	44.43
STNG_41-45	16.62	15.17	7.07	8.44	35.37	2.47	30.77	8.44	30.77
STNG_46-50	11.56	10.10	6.12	3.08	31.32	-0.68	23.80	3.08	23.80

Source:
NERC pc-GAR database

Notes
[6] = [1] - 2 * [3]
[7] = [1] + 2 * [3]
[8]: Higher value of [4] and [6]
[9]: Lower value of [5] and [7]

Appendix PQH-F, Table 8:
Benchmark Comparison of Average Equivalent Forced Outage Rate Proxy and Capacity Factors By Technology and Age

First Half - 2000

		California Big Five			National Benchmark		
Technology	Age Bracket	EFORP	Capacity Factor in Prior Period	EFORP/NCF	EFORP	Capacity Factor in Prior Period	EFORP/NCF
[1]	[2]	[3]	[4]	[5]	[5]	[6]	[7]
CTFO	21-25	0.67	2.52	0.27	0.88	2.10	0.42
CTFO	26-30	.	1.78	.	4.20	2.06	2.04
CTFO	31-35	3.50	1.61	2.17	1.30	1.38	0.94
CTNG	21-25	3.14	25.27	0.12	2.20	4.80	0.46
CTNG	26-30	0.10	2.26	0.05	2.54	8.76	0.29
CTNG	31-35	0.86	2.08	0.41	1.74	3.44	0.51
STNG	26-30	1.73	16.52	0.10	4.77	37.56	0.13
STNG	31-35	7.93	52.70	0.15	4.50	36.92	0.12
STNG	36-40	3.47	33.44	0.10	2.52	32.04	0.08
STNG	41-45	6.67	30.78	0.22	6.60	20.72	0.32
STNG	46-50	5.58	22.32	0.25	3.82	17.00	0.22

Notes:
[4]: Prior Period refers to the one-year-period prior to and including the period cited.
[5] = [3]/[4]; [7] = [5]/[6]

Appendix PQH-F, Table 9:
Benchmark Comparison of Average Equivalent Forced Outage Rate Proxy and Capacity Factors By Technology and Age

Second Half - 2000

		California Big Five			National Benchmark		
Technology	Age Bracket	EFORP	Capacity Factor in Prior Period	EFORP/NCF	EFORP	Capacity Factor in Prior Period	EFORP/NCF
[1]	[2]	[3]	[4]	[5]	[5]	[6]	[7]
CTFO	21-25	8.73	5.67	1.54	1.33	1.79	0.75
CTFO	26-30	0.00	1.96	0.00	1.96	1.49	1.32
CTFO	31-35	3.17	3.96	0.80	1.39	0.52	2.67
CTNG	21-25	3.45	27.38	0.13	4.73	6.01	0.79
CTNG	26-30	17.54	5.40	3.25	2.21	11.75	0.19
CTNG	31-35	3.88	5.40	0.72	2.00	2.60	0.77
STNG	26-30	9.80	35.71	0.27	4.80	37.05	0.13
STNG	31-35	13.88	53.56	0.26	5.14	35.34	0.15
STNG	36-40	11.09	42.82	0.26	4.29	32.35	0.13
STNG	41-45	16.03	38.28	0.42	3.96	22.08	0.18
STNG	46-50	9.75	32.41	0.30	4.29	16.76	0.26

Notes:
[4]: Prior Period refers to the one-year-period prior to and including the period cited.
[5] = [3]/[4]; [7] = [5]/[6]

Appendix PQH-F, Table 10:
Benchmark Comparison of Average Equivalent Forced Outage Rate Proxy and Capacity Factors By Technology and Age

First Half - 2001

			California Big Five			National Benchmark	
Technology	Age Bracket	EFORP	Capacity Factor in Prior Period	EFORP/NCF	EFORP	Capacity Factor in Prior Period	EFORP/NCF
[1]	[2]	[3]	[4]	[5]	[5]	[6]	[7]
CTFO	21-25	19.12	15.26	1.25	.	.	.
CTFO	26-30	49.37	2.31	21.36	.	.	.
CTFO	31-35	5.56	8.61	0.65	.	.	.
CTNG	21-25	6.78	37.10	0.18	.	.	.
CTNG	26-30	14.33	14.03	1.02	.	.	.
CTNG	31-35	9.89	14.50	0.68	.	.	.
STNG	26-30	16.69	56.78	0.29	.	.	.
STNG	31-35	10.78	55.19	0.20	.	.	.
STNG	36-40	4.65	56.61	0.08	.	.	.
STNG	41-45	15.10	46.33	0.33	.	.	.
STNG	46-50	19.20	44.09	0.44	.	.	.

Notes:
[4]: Prior Period refers to the one-year-period prior to and including the period cited.
[5] = [3]/[4]; [7] = [5]/[6]

Note:
National Benchmark NERC pc-GAR data not available for 2001.

APPENDIX PQH – G:

Derivation of GADS Outage Data, Capacity Data and Processing of SLIC Availability Data

This appendix documents the methodology to derive event-based GADS data, the derivation of capacity data and the conversion of SLIC event based date into SLIC hourly data.

1. Derivation of GADS Outage Data

Before converting the event-based data to hourly data, the raw GADS data was cleaned from any overlaps that existed between outage events. In the process of eliminating overlaps, the convention used was to keep the event with lower MW availability over the event with higher MW availability that occurred in the same time period.

Example 1a: Outage A lasts from 12/03/00 6:00PM to 12/10/00 6:00PM with 90MW availability and Outage B lasts from 12/04/00 10:00PM to 12/5/00 10:00PM with 10MW availability. The overlap from 12/04/00 10PM to 12/5/00 10:00PM was cleaned in the following way:
Event 1: 12/03/00 6:00PM - 12/04/00 10:00PM with 90MW availability
Event 2: 12/04/00 10:00PM - 12/5/00 10:00PM with 10MW availability
Event 3: 12/5/00 10:00PM - 12/10/00 6:00PM with 90MW availability.

Example 1b: Outage A lasts from 12/03/00 6:00PM to 12/10/00 10:00PM with 10 MW availability and Outage B lasts from 12/04/00 10:00PM to 12/5/00 10:00PM with 90MW availability. In this case, since Outage B is completely overlapping with Outage A and Outage A has a lower MW availability, the entry for Outage B is completely dropped from the GADS data.

Example 1c: Outage A lasts from 12/03/00 6:00PM to 12/10/00 10:00PM with 10 MW availability and Outage B lasts from 12/05/00 8:00PM to 12/12/00 12:00AM with 100MW availability. The overlap from 12/5/00 8:00PM to 12/12/00 12:00 AM was cleaned in the following way:
Event 1: 12/03/00 6:00 - 12/10/00 10:00PM with 10MW availability
Event 2: 12/10/00 10:00PM - 12/12/00 12:00AM with 100MW availability.

Example 1d: Outage A lasts from 12/03/00 6:00PM to 12/10/00 10:00PM with 100MW availability and Outage B lasts from 12/05/00 8:00PM to 12/12/00 12:00AM with 10MW availability. The overlap from 12/5/00 8:00PM to 12/12/00 12:00AM was cleaned in the following way:
Event 1: 12/03/00 6:00 - 12/05/00 8:00PM with 100MW availability
Event 2: 12/05/00 8:00PM - 12/12/00 12:00AM with 10MW availability.

Apart from removing the overlaps within the GADS data we made some necessary adjustments and assumptions:

Assumptions and Adjustments for all Generators:

1) Outage entries that occur over more than one month were adjusted to reflect the month in which each portion of it occurred.
2) Whenever, the raw GADS data included entries of reserve shutdowns as well as other outage events, the entries of reserve shutdowns were separated from the other outage events as reserve shutdowns are not outages.

Assumptions and Adjustments Specific to Dynegy:

1) In the raw GADS data, there were instances with missing end or start time information. Whenever Dynegy did not provide one of start time, end time or duration, these gaps were filled by calculations. For example, the raw GADS data for the Division St. unit reports an outage event from 11/09/00 22:30 until 11/09/00 (end time missing.) In this instance, the duration of the event is given as 1.5 hours. Thus, the end time is calculated to be 23.59.

   For reported outage events, where both start and end time were missing, the gaps were filled using the start times from SLIC records that matched the start and end dates provided by the generator, and the duration provided by the generator. (Note: The end times in the SLIC data tended to vary from the generator data by a few hours.) Events that could not be matched to the SLIC records were assumed to have a start time of 12:00 AM on the start date, and last for the duration provided by the generator.

   Finally, for events where no start time, end time or duration was given, missing time information was obtained using the start and end times from SLIC records that matched the start and end dates provided by the generator.

2) Some of the outage events reported in the GADS data sets did not have the outage type information. The following events were assigned as Forced based on the verbal descriptions provided.

Unit Name	Start Date/Time	End Date/Time	Verbal Description
Long Beach 5	11/13/00 12:15 PM	11/13/00 12:20 PM	water in combustor
Long Beach 2	4/20/00 3:34 PM	4/20/00 11:59 PM	no steam inj.
Long Beach 2	12/13/00 12:01 AM	12/13/00 11:59 PM	steam drain pipe leak

3) Outage types assigned for Dynegy are:

Reported Event Type	Assigned Event Type
D1	F
D2	F
D4	M
FO	F
MO	M
PD	P
PO	P
SF	F
SO	P
U1	F
U2	F
U3	F

Assumptions and Adjustments Specific to Reliant

Outage types assigned for Reliant are:

Reported Event Type	Assigned Event Type
Forced Derating - Delayed	F
Forced Derating - Immediate	F
Forced Derating - Postponed	F
Forced Outage - Delayed	F
Forced Outage - Immediate	F
Forced Outage - Postponed	F
Maintenance Derating	M
Maintenance Outage	M
Planned Outage	P
Scheduled Outage Extension	P
Startup Failure	F

Assumptions and Adjustments Specific to Duke:

1) In some of the raw data files, the available capacity during the outage was not given. However, net curtailment was provided so we were able to derive the available capacity by subtracting the net curtailment from the total capacity[1] of the unit.
2) Outage types were assumed to the following:

Outage Type	Assigned Outage Type
Delayed Curtailment	F
Delayed Unit Outage	F
Event Type SE	P
Immediate Curtailment	F
Immediate Unit Outage	F
Maintenance Curtailment	M
Maintenance Derating	M
Maintenance Outage	M
No Curtailment	P
Planned Derating	P
Planned Outage	P
Postponed Curtailment	F
Postponed Unit Outage	F
Scheduled Outage Extension	P
Section D Event	P
Startup Failure	F
Unplanned (Forced) Derating – Delayed	F
Unplanned (Forced) Derating – Immediate	F
Unplanned (Forced) Derating – Postponed	F
Unplanned (Forced) Outage – Delayed	F
Unplanned (Forced) Outage – Immediate	F
Unplanned (Forced) Outage – Postponed	F

[1] Derivation of the unit capacities is explained in the "Capacity Data" section.

Assumptions and Adjustments Specific to Mirant:

1) In some of the raw data files, the available capacity during the outage was not given. However, net curtailment was provided so we were able to derive the available capacity by subtracting the net curtailment from the total capacity of the unit.
2) Outage types assigned for Mirant are:

Reported Type	Assigned Type
D1	F
D2	F
D3	F
D4	M
MO	M
PD	P
PO	P
U1	F
U2	F
U3	F

Assumptions and Adjustments Specific to AES/Williams:

The AES outage data was in an hourly format for the 18-month period. Thus, the data was converted in an event-based format. Whenever the MW availability of the plant or the reason of an outage changed, a new event was recorded.

At times, the event types and reason were not reported within the hourly information. In those cases, the event type and reason was assigned to the event by matching the event in the hourly data to the events in the summary box provided in the same sheet. Whenever, an event was not available in the summary box or a summary box did not exist, the event was matched to an event-based outage data set we received from AES/Williams[2]. For the months where no data from these CD's were available, the event was matched to the SLIC outage table entries to assign an outage type. If the event reason was known but the type was lacking, we were able to assign event types by looking at other events with the same reason that provided their types as well. Finally, if an event was lacking both outage type and reason information, and could not be matched to any of the above mentioned sources, the event was assumed to be a maintenance event.

[2] AGO CD's 1, 3, & 6.

2. Derivation of Capacity Data

To derive unit capacity, several sources were used. First, capacity declared by the generator has been considered. The sources for this category are the GADS data and individual responses of the generators to the CPUC report. After collecting capacity data from these two sources, the minimum of the two was used. Whenever data provided by the generator was not available, unit capacity data provided by the ISO was used. ISO sources were the ISO's Generator List posted on their webpage on April 2001, June 2001 and January 2003, SLIC table named "res_gen_tbl" and SLIC Availability Log named "gen_abail_tbl" received by the CAISO in response to CAL-ISO-34[3]. For the data coming from the res_gen_tbl, the minimum of reported P-Max and Capacity was considered. For the SLIC Availability log, the minimum of the maximum of UA_PMAX and the maximum of UA_AVAIL entries was considered. The final unit capacity number from the ISO sources is the minimum capacity reported in the above mentioned sources. See Capacity Worksheet for details.

[3] Supplemental Response to CAL-ISO-34, provided January 17, 2003.

APPENDIX PQH - G: Generation Capacity Worksheet

Company	Unit ID	Generator Data: Based on Outage Data	Generator Data: Response to CPUC Report	ISO Data: 20010402 ISO Generator List 4/01	ISO Data: 20010402 ISO Generator List 6/02	ISO Data: 20010402 ISO Generator List 1/03	ISO Data: res_gen	ISO Data: gen_shell_tbl	Final Generator Data	Final ISO Data	Capacity (Final)
		(MW)				(MW)				(MW)	
		[1]	[2]	(3)	[4]	[5]	[6]	[7]	[8]	[9]	[10]
AES/Williams	ALAMIT_7_UNIT 1	175 00		171 00	171 00	171 00	174 56	175 00	175 00	171 00	175 00
AES/Williams	ALAMIT_7_UNIT 2	175 00		176 60	176 60	176 60	175 00	176 60	175 00	175 00	175 00
AES/Williams	ALAMIT_7_UNIT 3	320 00		322 00	322 00	325 96	320 00	322 00	320 00	320 00	320 00
AES/Williams	ALAMIT_7_UNIT 4	320 00		320 00	320 00	324 31	320 00	320 00	320 00	320 00	320 00
AES/Williams	ALAMIT_7_UNIT 5	480 00		482 00	482 00	485 00	480 00	482 00	480 00	480 00	480 00
AES/Williams	ALAMIT_7_UNIT 6	480 00		481 00	481 00	485 17	480 00	481 00	480 00	480 00	480 00
AES/Williams	ALAMIT_7_UNIT 7	133 00		134 00	134 00	134 00	133 00	134 00	133 00	133 00	133 00
AES/Williams	HNTGBH_7_UNIT 1	215 00		215 00	215 00	215 00	215 00	215 00	215 00	215 00	215 00
AES/Williams	HNTGBH_7_UNIT 2	215 00		215 00	215 00	215 00	215 00	215 00	215 00	215 00	215 00
AES/Williams	HNTGBH_7_UNIT 5	133 00		133 00	128 00		133 00	133 00	133 00	128 00	133 00
AES/Williams	REDOND_7_UNIT 5	175 00		175 00	175 00	175 00	175 00	175 00	175 00	175 00	175 00
AES/Williams	REDOND_7_UNIT 6	175.00		175 40	175 40	175 40	175 00	175 40	175 00	175 00	175 00
AES/Williams	REDOND_7_UNIT 7	480 00		483 00	483 00	483 00	480 00	483 00	480 00	480 00	480 00
AES/Williams	REDOND_7_UNIT 8	480 00		484 00	484 00	486 87	480 00	484 00	480 00	480 00	480 00
Duke	MORBAY_7_UNIT 1	163 00		171 00	171 00	171 00	163 00	171 00	163 00	163 00	163 00
Duke	MORBAY_7_UNIT 2	163 00		171 00	171 00	171 00	163 00	171 00	163 00	163 00	163 00
Duke	MORBAY_7_UNIT 3	338 00	337	343 00	343	343	337 00	343 00	337 00	337 00	337 00
Duke	MORBAY_7_UNIT 4	338 00		336 00	336.00	336 00	336 00	336 00	338 00	336 00	338 00
Duke	MOSSLD_7_UNIT 6	750.00		743 00	748 85	754 33	739 00	743 00	750 00	739 00	750 00
Duke	MOSSLD_7_UNIT 7	739.00		742 00	742 00	755 70	739 00	742 00	739 00	739 00	739 00
Duke	OAK C_7_UNIT 1	56 00		57 71	57 70	57 70	57 70	57 70	56 00	57 70	56 00
Duke	OAK C_7_UNIT 2	55 00		51 00	51 00	51 00	51 00	55 00	55 00	51 00	55 00
Duke	OAK C_7_UNIT 3	55 00		49 00	49 00	49 00	49 00	55 00	55 00	49 00	55 00
Duke	SOBAY_7_GT1	15 00		18 00	15 00	15 00	15.00	15 00	15 00	15 00	15 00
Duke	SOBAY_7_SY1	146 00		146 80	146 00	146 00	146 00	146 80	146 00	146 00	146 00
Duke	SOBAY_7_SY2	150 00		149 60	149 60	149 60	149 60	149 60	150 00	149 60	150 00
Duke	SOBAY_7_SY3	175 00		176 40	175 00	175 00	175 00	176 40	175 00	175 00	175 00
Duke	SOBAY_7_SY4	222 00	222	225 80	222	222	222 00	225 80	222 00	222 00	222 00
Dynegy	DIVSON_7_DIGT1			17 00	14 00	14 00	17 00	17 00		14 00	14 00
Dynegy	DIVSON_7_NSGT1			47 00	22 00		29 00	29 00		22 00	22 00
Dynegy	ELCAJN_7_GT1			17 00	15 00	15 00	17 00	17 00		15 00	15 00
Dynegy	ELSEGN_7_UNIT 1	175 00		175 00	175 00		175 00	175 00	175 00	175 00	175 00
Dynegy	ELSEGN_7_UNIT 2	175 00		164 00	164 00		164 00	164 00	175 00	164 00	175 00
Dynegy	ELSEGN_7_UNIT 3	335 00		337 00	335 00	335 00	335 00	337 00	335 00	335 00	335 00
Dynegy	ELSEGN_7_UNIT 4	335 00		335 00	335 00	335 00	335 00	335 00	335 00	335 00	335 00
Dynegy	ENCINA_7_EA1			103 50	103 50	103 50	103 50	106 00		103 50	103 50
Dynegy	ENCINA_7_EA2			104 50	103 00	103 00	104 00	104 50		103 00	103 00
Dynegy	ENCINA_7_EA3			111 10	110 00	110 00	110 00	111 10		110 00	110 00
Dynegy	ENCINA_7_EA4			303 40	300 00	300 00	300.00	303 40		300 00	300 00
Dynegy	ENCINA_7_EA5			331 60	330 00	330 00	330 00	331 60		330 00	330 00
Dynegy	ENCINA_7_GT1			16 62	16 62	16 62	16 62	16 62		16 62	16 62
Dynegy	KEARNY_7_KY1			17 00	17 00	16 00	17 00	17 00		16 00	16 00
Dynegy	KEARNY_7_KY2				60 00	59.00	72 00	72 00		59 00	59 00
	sum of sub-units			63 35	63 35	59 00				59 00	59 00
Dynegy	KEARNY_7_KY2A			16 09	16 09	15 00	15 00			15 00	15 00
Dynegy	KEARNY_7_KY2B			17 09	17 09	15 00	15 00			15 00	15 00
Dynegy	KEARNY_7_KY2C			15 12	15 12	15 00	15 00			15 00	15 00
Dynegy	KEARNY_7_KY2D			15 07	15 07	14 00	14 00			14 00	14 00
Dynegy	KEARNY_7_KY3				60 00	61 00	71 00	71 00		61 00	61 00
	sum of sub-units			66 29	66 29	61 00				61 00	61 00
Dynegy	KEARNY_7_KY3A			17.33	17 33	16 00	16 00			16 00	16 00
Dynegy	KEARNY_7_KY3B			16 77	16 77	15 00	15 00			15 00	15 00
Dynegy	KEARNY_7_KY3C			16 22	16 22	15 00	15 00			15 00	15 00
Dynegy	KEARNY_7_KY3D			15 97	15 97	15 00	15 00			15 00	15 00
Dynegy	LBEACH_2_230TOT			172 20	170 00	170 00	170 00	172 20		170 00	180 00
	sum of sub-units	180 00			172 00	172 00			180 00	172 00	180 00
Dynegy	LBEACH_2_UNIT 5	60 00			58 00	58 00	58 00		60 00	58 00	60 00
Dynegy	LBEACH_2_UNIT 6	60 00			57 00	57 00	57 00		60 00	57 00	60 00
Dynegy	LBEACH_2_UNIT 7	60 00			57 00	57 00	57 00		60 00	57 00	60 00
Dynegy	LBEACH_6_66TOT			380 00	380 00	380 00	380 00	380 00		380 00	400 00
	sum of sub-units	400 00			380 00	380 00	380 00		400 00	380 00	400 00
Dynegy	LBEACH_6_UNIT 1	60 00			63 00	63 00	63 00		60 00	63 00	60 00
Dynegy	LBEACH_6_UNIT 2	60 00			64 00	64 00	64 00		60 00	64 00	60 00
Dynegy	LBEACH_6_UNIT 3	60 00			58 50	58 50	58 50		60 00	58 50	60 00
Dynegy	LBEACH_6_UNIT 4	60 00			62 00	62 00	62 00		60 00	62 00	60 00
Dynegy	LBEACH_6_UNIT 8	80 00			65 50	65 50	65 50		80 00	65 50	80 00
Dynegy	LBEACH_6_UNIT 9	80 00			67 00	67 00	67 00		80 00	67 00	80 00
Dynegy	MRGT_7_UNITS				38 00	36 00	39 00	39 00		36 00	36 00
	sum of sub-units			38 96	39 00	36 00				36 00	36 00
Dynegy	MRGT_7_MR1A			19 99	20 00	18 00	18 00			18 00	18 00
Dynegy	MRGT_7_MR1B			18 97	19 00	18 00	18 00			18 00	18 00
Dynegy	OLDTWN_7_NTCGT1			16 00	15 00		16 00	16 00		15 00	15 00
Dynegy	CRNRDO_7_NIGT1				18 00		20 40	20 40		18 00	18 00
Dynegy	CRNRDO_7_NIGT2				18 00		20 90	20 90		18 00	18 00

APPENDIX PQH - G: Generation Capacity Worksheet

		Generator Data		ISO Data							
Company	Unit ID	Based on Outage Data	Response to CPUC Report	20010402 ISO Generator List 4/01	20010402 ISO Generator List 6/02	20010402 ISO Generator List 1/03	res_gen	gen_abail_thl	Final Generator Data	Final ISO Data	Capacity (Final)
		(MW)				(MW)				(MW)	
		[1]	[2]	(3)	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Mirant	COCOPP_7_UNIT 6	339 00	335	335 90	335 9	335 9	335 00	339 00	335 00	335 00	335 00
Mirant	COCOPP_7_UNIT 7	337 00	337	336 00	336	336	337 00	337 00	337 00	336 00	337 00
Mirant	PITTSP_7_UNIT 1	163 00	150	167 00	167	167	150 00	167 00	150 00	150 00	150 00
Mirant	PITTSP_7_UNIT 2	163 00	150	154 00	154	154	150 00	163 00	150 00	150 00	150 00
Mirant	PITTSP_7_UNIT 3	163 00	150	154 00	154	154	150 00	154 00	150 00	150 00	150 00
Mirant	PITTSP_7_UNIT 4	163 00	145	150 00	150	150	145 00	163 00	145 00	145 00	145 00
Mirant	PITTSP_7_UNIT 5	323 00	312	315 00	315	315	312 00	325 00	312 00	312 00	312 00
Mirant	PITTSP_7_UNIT 6	323 00	317	317 00	317	317	317 00	325 00	317 00	317 00	317 00
Mirant	PITTSP_7_UNIT 7	682 00	682	700 00	700	700	682 00	700 00	682 00	682 00	682 00
Mirant	POTRPP_7_UNIT 3	206 00	206	207 00	207	207	206 00	207 00	206 00	206 00	206 00
Mirant	POTRPP_7_UNIT 4	52 00	52	54 00	54	54	52 00	54 00	52 00	52 00	52 00
Mirant	POTRPP_7_UNIT 5	52 00	52	55 00	55	55	52 00	55 00	52 00	52 00	52 00
Mirant	POTRPP_7_UNIT 6	52 00	52	53 00	53	53	52 00	53 00	52 00	52 00	52 00
Reliant	CWATER_7_UNIT 1			63 00	63 00	63 00	63 00	63 00		63 00	63 00
Reliant	CWATER_7_UNIT 2			81 50	81 50	81 50	81,50	81 50		81 50	81 50
Reliant	CWATER_7_UNIT 3			245 30	245 30	245 30	245 30	245 30		245 30	241 00
	sum of sub-units					241 00				241 00	241 00
Reliant	CWATER_7_CT31					68 00	68 00			68 00	68 00
Reliant	CWATER_7_CT32					68 00	68 00			68 00	68 00
Reliant	CWATER_7_ST30					105 00	105 00			105 00	105 00
Reliant	CWATER_7_UNIT 4			245 90	245 90	245 90	245 90	245 90		245 90	241 00
	sum of sub-units					241 00				241 00	241 00
Reliant	CWATER_7_CT41					68 00	68 00			68 00	68 00
Reliant	CWATER_7_CT42					68 00	68 00			68 00	68 00
Reliant	CWATER_7_ST40					105 00	105 00			105 00	105 00
Reliant	GOLETA_6_ELLWOD					56 10	56 10	56 10		56 10	56 10
Reliant	ETIWND_7_UNIT 1			134 70	132 00		134 70	134 70		132 00	132 00
Reliant	ETIWND_7_UNIT 2			133 90	132 00		133 90	133 90		132 00	132 00
Reliant	ETIWND_7_UNIT 3			320 00	320 00	320.00	320 00	320 00		320 00	320 00
Reliant	ETIWND_7_UNIT 4			320 00	320 00	320 00	320 00	320 00		320 00	320 00
Reliant	ETIWND_7_UNIT 5			140 90	130 00	120 00	120 00	140 90		120 00	120 00
Reliant	MNDALY_7_UNIT 1			218 00	218 00	218 00	215 00	218 00		215 00	215 00
Reliant	MNDALY_7_UNIT 2			215 29	215 29	215 29	215 29	215 29		215 29	215 29
Reliant	MNDALY_7_UNIT 3			131 90	131 90	120 00	120 00	131 90		120 00	120 00
Reliant	ORMOND_7_UNIT 1			724 60	724 60	724 60	724 60	724 60		724 60	724 60
Reliant	ORMOND_7_UNIT 2			766 00	766 00	775 00	750 00	766 00		750 00	750 00

Sources and Notes·

[1] Generator Outage Data

AES Outage data received in CD CAL-AES 01293 All data comes from the 5_9_01 FERC Request,
except for Huntington Beach 1 In 2000 and Huntington Beach 2 between January 2000 - August 2000 which come from the 8_10_01 FERC Request

Dynegy GADS event data received in response to CA-DYN - 1 -7 from CD dated 1/21/03, Docket No EL00 - 95-069, et al
Data for Long Beach comes from the Second Response to First Set of Data Requests CA-DYN -1-35

Duke GADS event data received in response to CAL-DUKE-58 and CAL-DUKE-183 on 1/29/03 from FERC proceeding CD 26
The capacity numbers reported correspond to the maximum curtailment in the previous sources

Mirant GADS event data received on 2/3/03 in response to CAL-MIR-58 in CD 1278
The capacity numbers reported correspond to the maximum curtailment in the previous sources

Reliant GADS Event Data (Report 97) Received in response to CA -REL -1-35

[2] Generator responses to CPUC report

Duke Duke Energy's response to CPUC dated September 26, 2002 Subject 'Re CPUC's "Wholesale Generator Investigation Report" dated September 17, 2002'

Mirant Mirant's response to the CPUC report dated September 26, 2002 Subject 'Re Mirant Response to 9/17/02 Paper Presented by Commissioner Loretta Lynch.'

[3] Master CAISO Control Area Generating Capability List, posted on their web site in 4/01

[4]. Master CAISO Control Area Generating Capability List, posted on their web site in 6/02
For DIVSON_7_NSGT1, the entry associated with Cabrillo II was chosen

[5] Master CAISO Control Area Generating Capability List, posted on their web site in 1/03

[6]. SLIC res_gen tables
ISO's Supplemental Response to CAL-ISO-34, provided January 17, 2003 Capacity numbers represent the min(Pmax, capacity)

[7]. SLIC gen_abail tables
ISO's Supplemental Response to CAL-ISO-34, provided January 17, 2003 Capacity numbers represent the (min(max(UA_PMAX), max(UA_AVAIL)).

[8] = Min ([1], [2])

[9] = Min ([3]:[7])

[10] = [8] if available
= [9] otherwise

3. Conversion of CAISO's SLIC Availability Data into Hourly Availability Data:

The SLIC availability log data reflects changes in availability of units. The date and time stamp is converted to a date and hour ending format for purposes of summarization. We assumed the unit at full capacity prior to the first event.

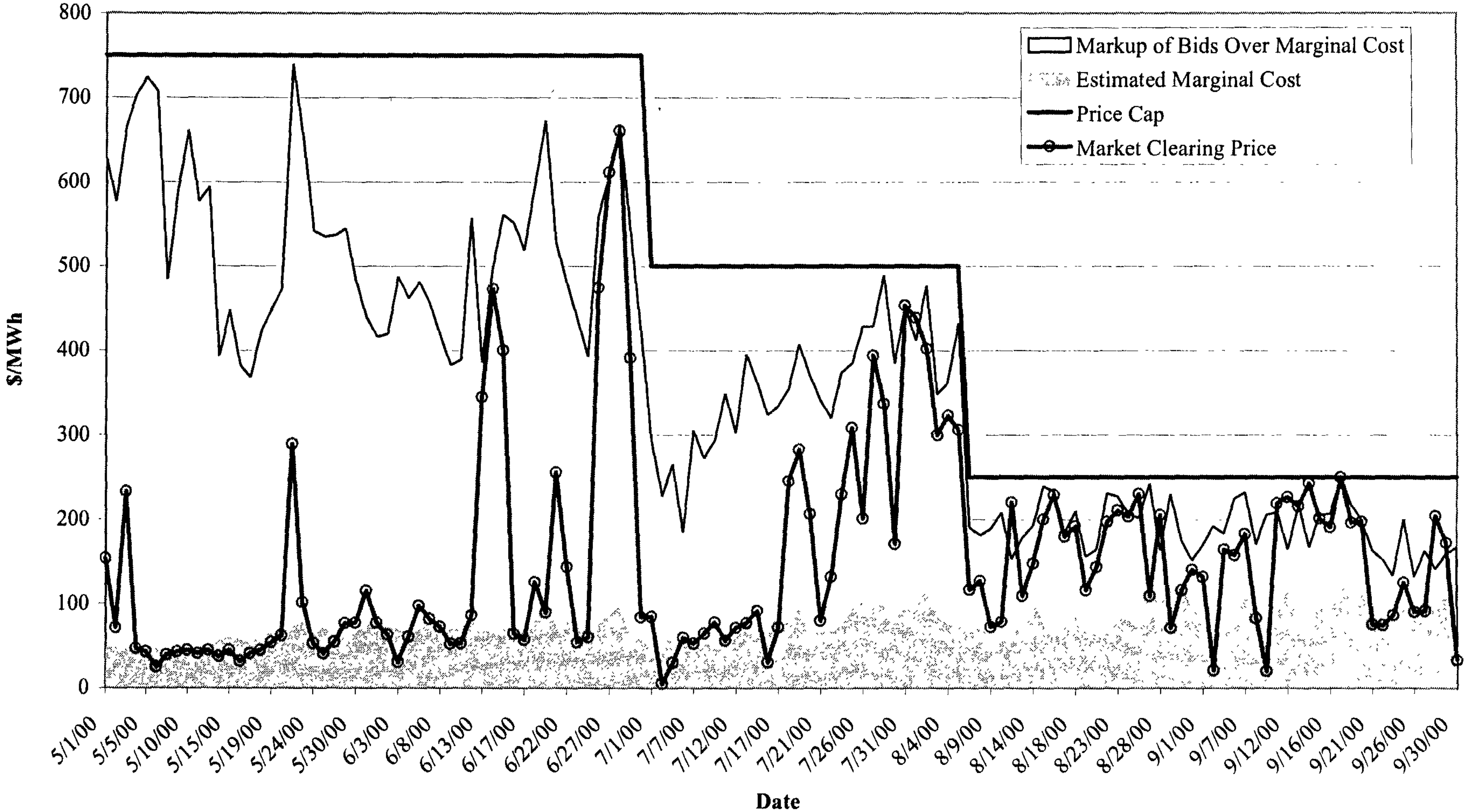
The following two step approach puts the log data into an hourly form.

The first step identifies the event yielding minimum availability in each hour from the SLIC data. The step also identifies the last chronological event occurring within the hour. This information is then merged into an hourly dataset listing all hours from 1/1/00 HE 1 – 6/30/01 HE 24 for all units of a particular company.

The second step fills in the blanks between the hours where events are recorded. For the hour in which an event is recorded, the event yielding minimum availability defines that hour's availability. For all hours subsequent to the event but prior to the next event, the last chronological event in the start hour of the event defines availability.

<u>Example:</u> Event A is recorded on 5/15/00 7:18 AM, with availability listed as 40 MW. Event B is recorded on 5/15/00 7:34 AM, with availability listed as 0 MW. Event C is recorded on 5/15/00 7:50 AM, with availability listed as 25 MW. No other events are recorded until Event D at 5/19/00 6:24 AM, which yields availability of 100 MW. For 5/15/00 HE 8, availability is recorded as 0 MW, because Event B has the lowest availability in that hour. For 5/15/00 HE 9 – 5/19/00 HE 6, availability is recorded as 25 MW, because Event C was the last event to be recorded. 5/19/00 HE 7 receives an availability of 100 MW, because it is the only event recorded for that hour.

Appendix PQH-H
AES/Williams Energy Services Corporation
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
5/1/00 - 10/1/00



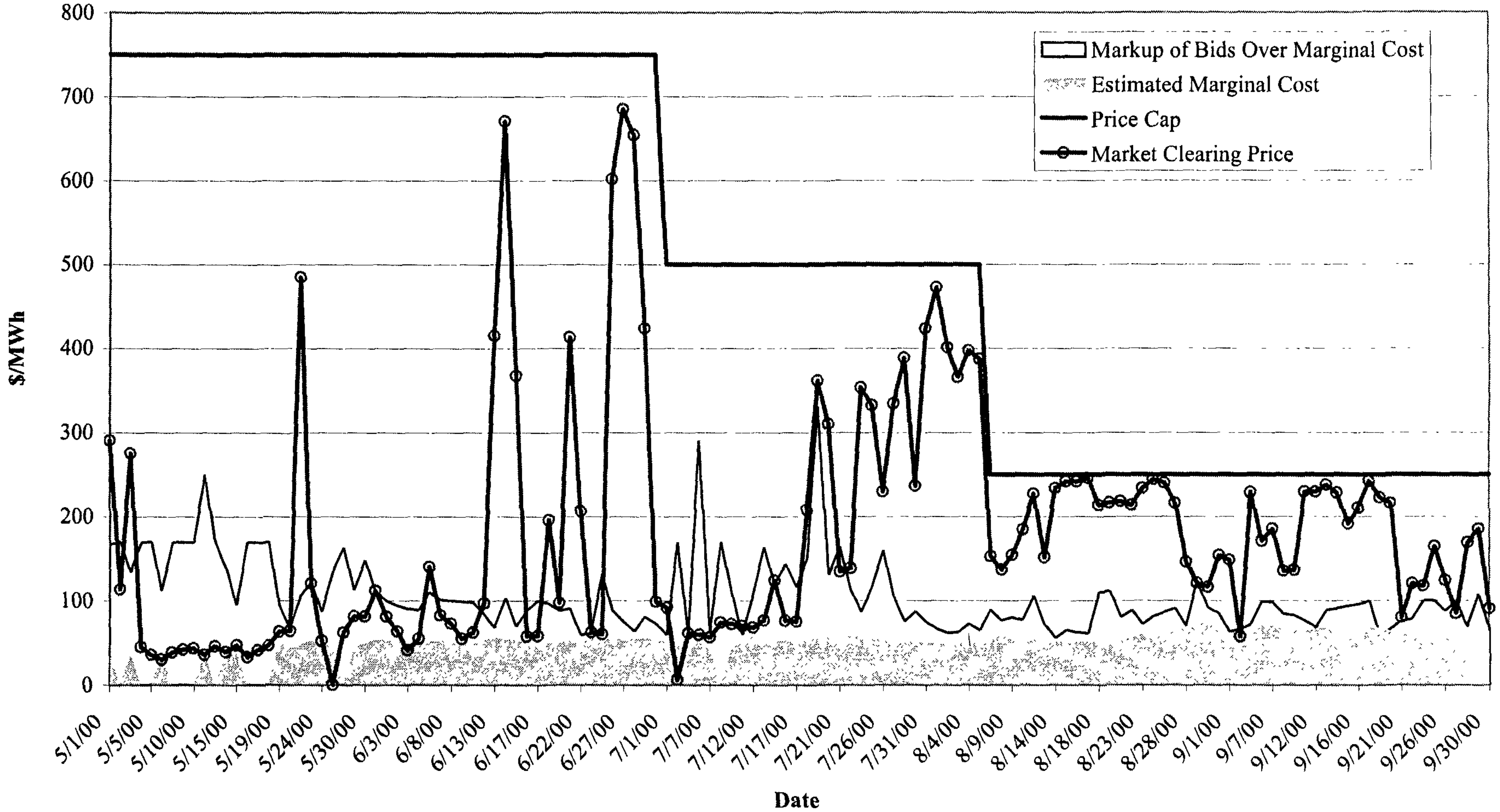
Notes and Sources:

[1]: Bid data from CAISO BEEP Stack data. Daily average prices are weighted by MW bid.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

[3]: Market clearing prices provided by ISO in response to CAAG subpoenas (received via waiver). Market clearing prices are 10-minute incremental prices averaged over hours and then over days. Daily average market clearing prices are weighted by real-time demand.

Appendix PQH-H
Duke Energy Trading and Marketing, L.L.C.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
5/1/00 - 10/1/00



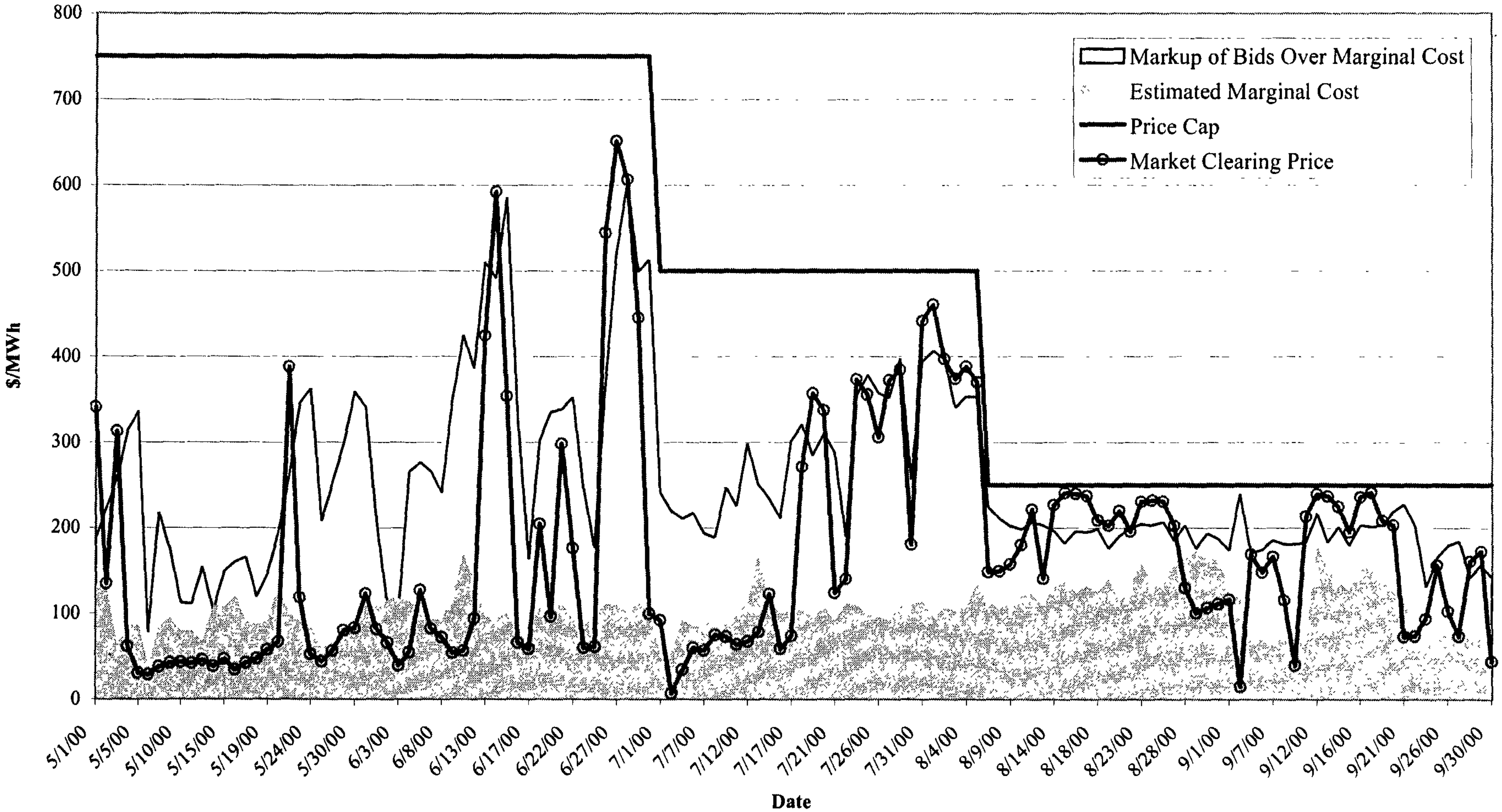
Notes and Sources:

[1]: Bid data from CAISO BEEP Stack data. Daily average prices are weighted by MW bid.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

[3]: Market clearing prices provided by ISO in response to CAAG subpoenas (received via waiver). Market clearing prices are 10-minute incremental prices averaged over hours and then over days. Daily average market clearing prices are weighted by real-time demand.

Appendix PQH-H
Dynegy/Electric Clearinghouse
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
5/1/00 - 10/1/00



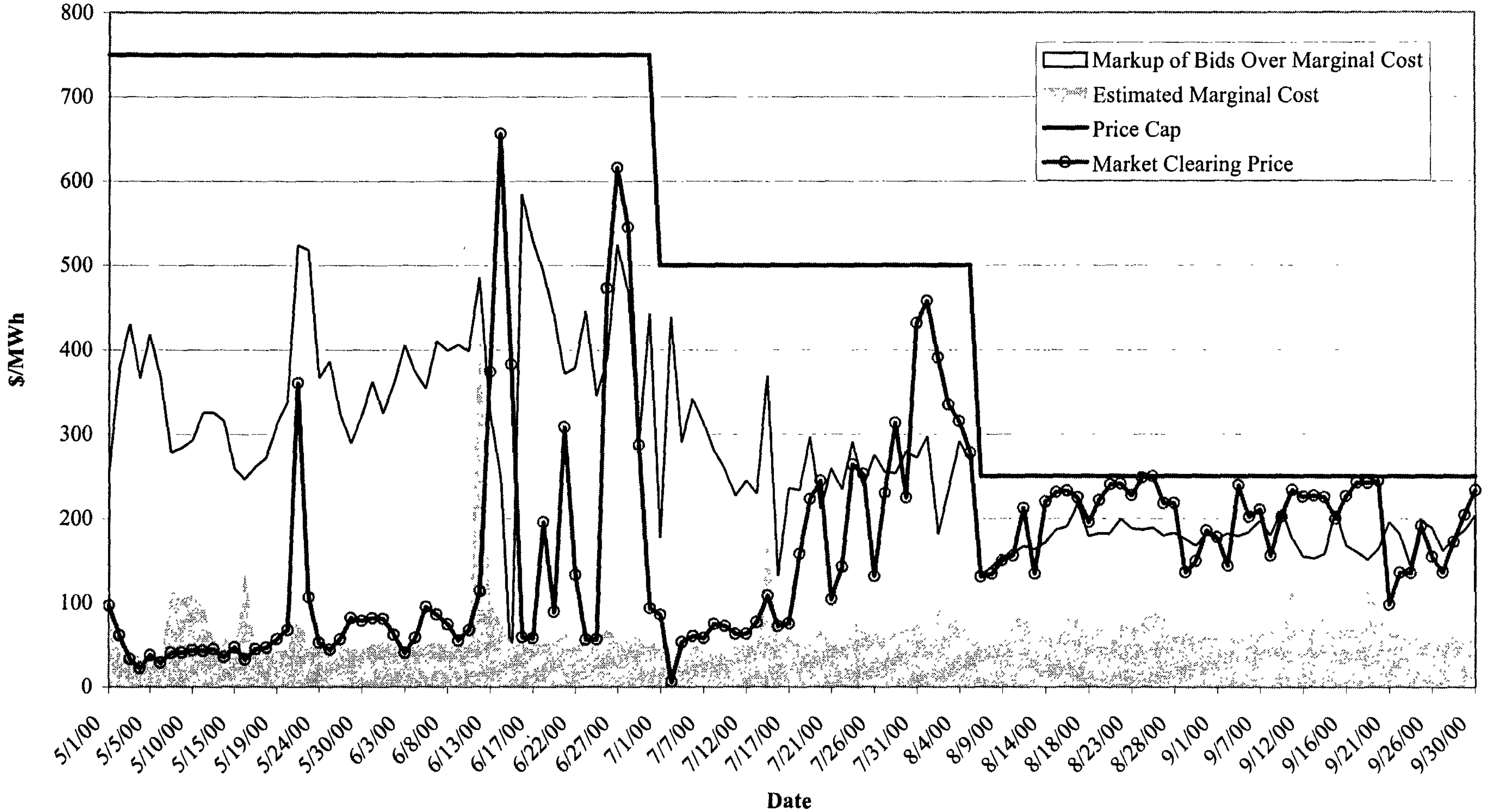
Notes and Sources:

[1]: Bid data from CAISO BEEP Stack data. Daily average prices are weighted by MW bid.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

[3]: Market clearing prices provided by ISO in response to CAAG subpoenas (received via waiver). Market clearing prices are 10-minute incremental prices averaged over hours and then over days. Daily average market clearing prices are weighted by real-time demand.

Appendix PQH-H
Mirant/Southern Company Energy Marketing, L.P.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
5/1/00 - 10/1/00



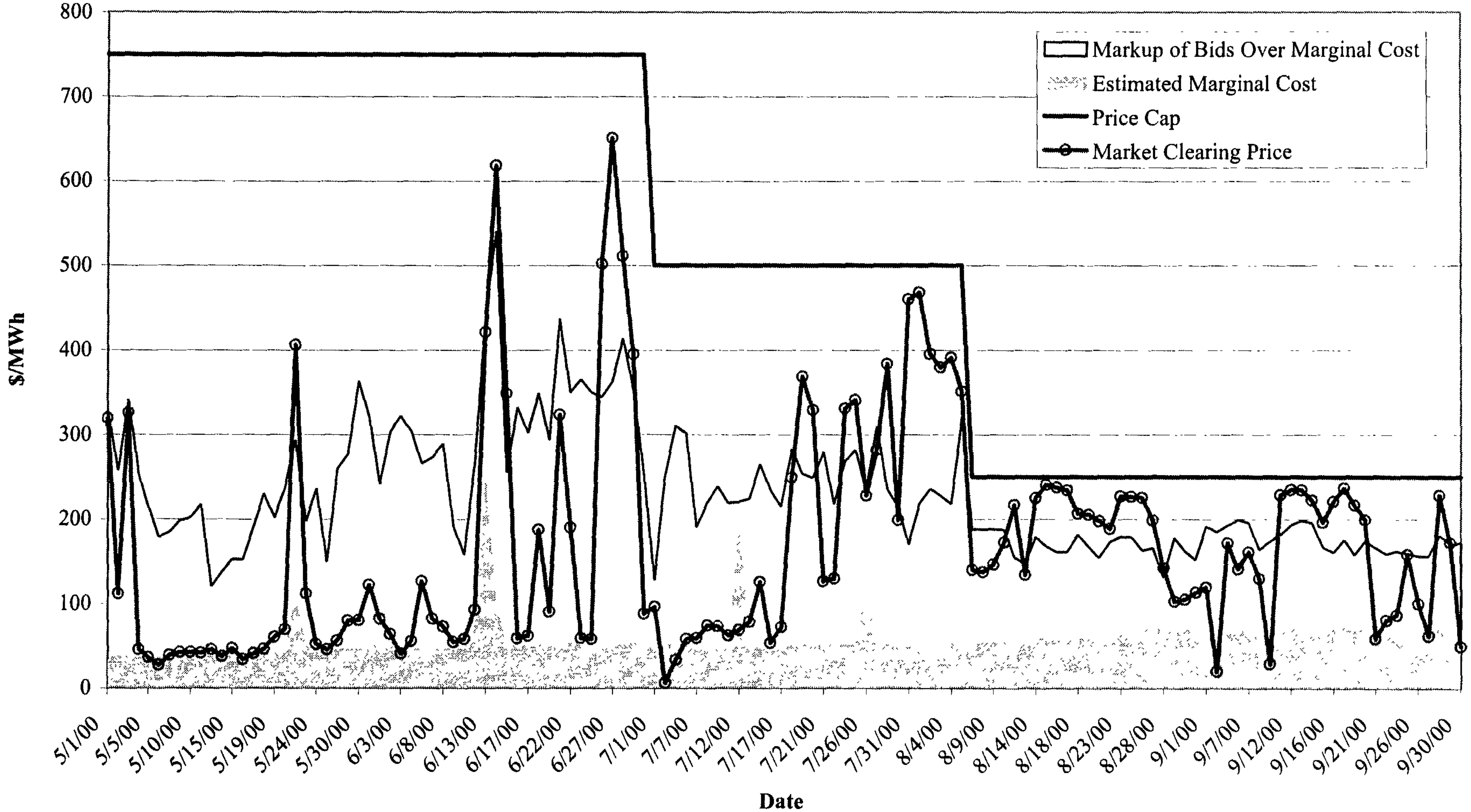
Notes and Sources:

[1]: Bid data from CAISO BEEP Stack data. Daily average prices are weighted by MW bid.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

[3]: Market clearing prices provided by ISO in response to CAAG subpoenas (received via waiver). Market clearing prices are 10-minute incremental prices averaged over hours and then over days. Daily average market clearing prices are weighted by real-time demand.

Appendix PQH-H
Reliant Energy Services, Inc.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
5/1/00 - 10/1/00



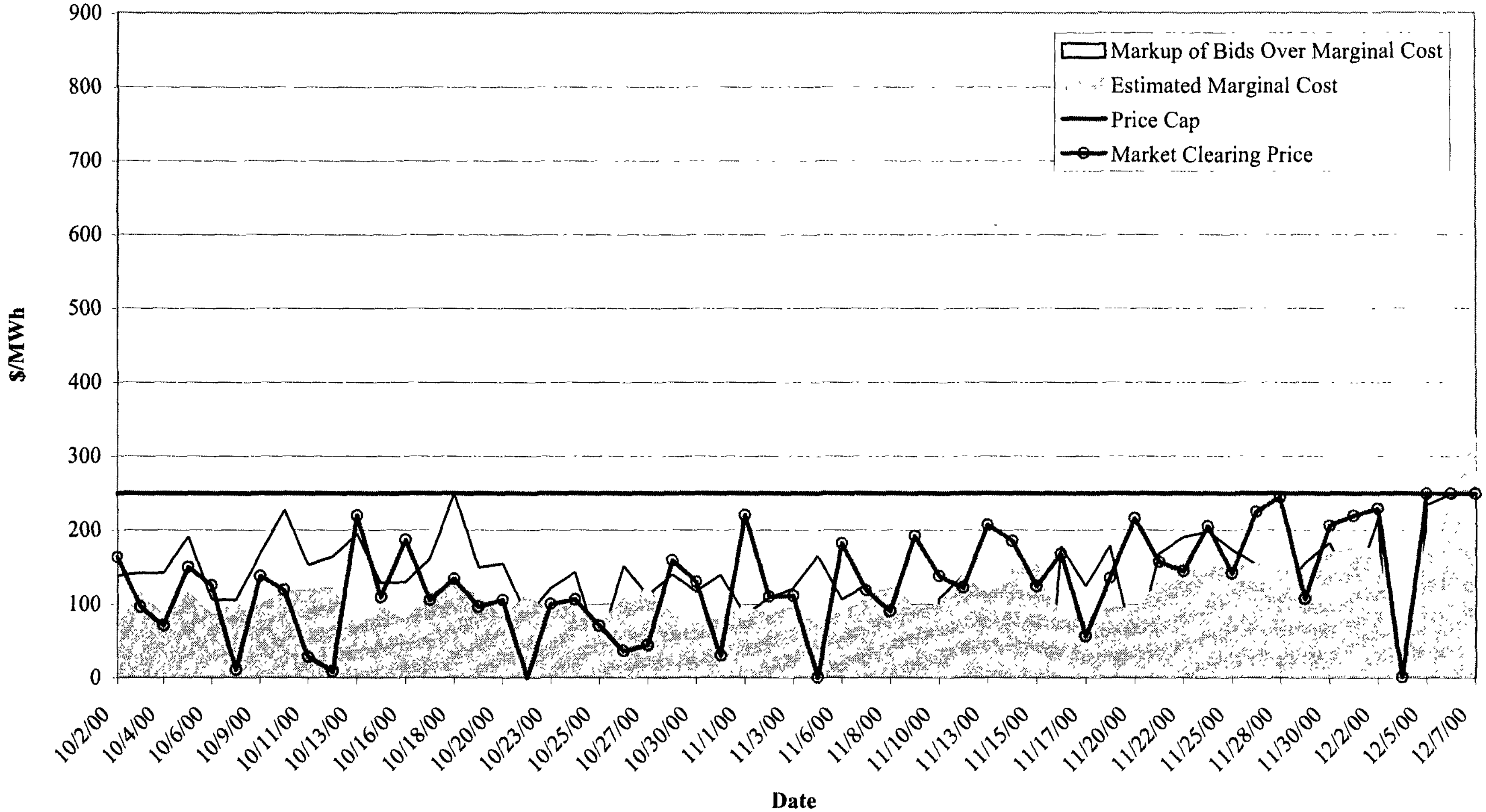
Notes and Sources:

[1]: Bid data from CAISO BEEP Stack data. Daily average prices are weighted by MW bid.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

[3]: Market clearing prices provided by ISO in response to CAAG subpoenas (received via waiver). Market clearing prices are 10-minute incremental prices averaged over hours and then over days. Daily average market clearing prices are weighted by real-time demand.

Appendix PQH-H
AES/Williams Energy Services Corporation
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
10/2/00 - 12/7/00



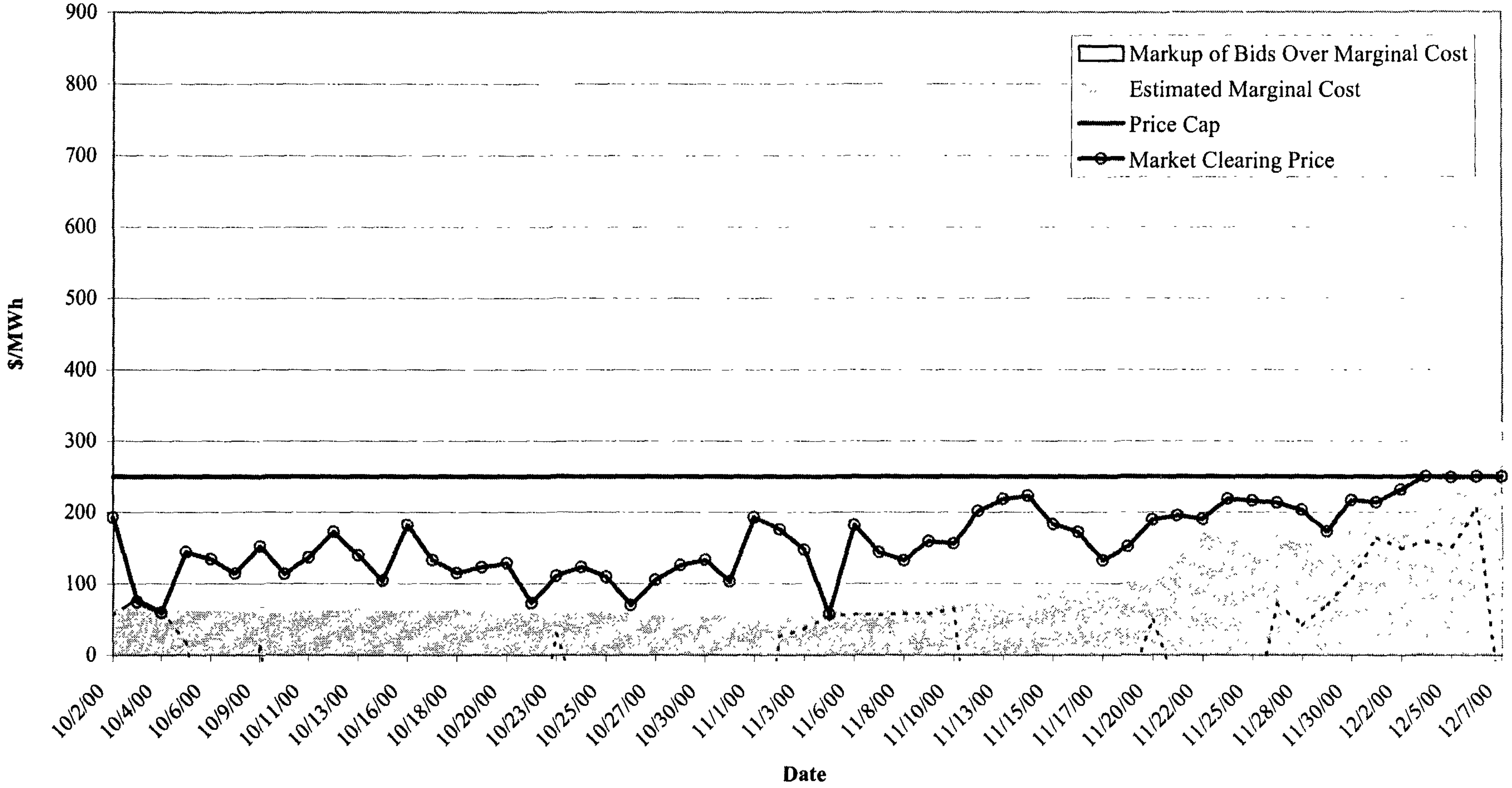
Notes and Sources:

[1]: Bid data from CAISO BEEP Stack data. Daily average prices are weighted by MW bid.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

[3]: Market clearing prices provided by ISO in response to CAAG subpoenas (received via waiver). Market clearing prices are 10-minute incremental prices averaged over hours and then over days. Daily average market clearing prices are weighted by real-time demand.

Appendix PQH-H
Duke Energy Trading and Marketing, L.L.C.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
10/2/00 - 12/7/00



Notes and Sources:

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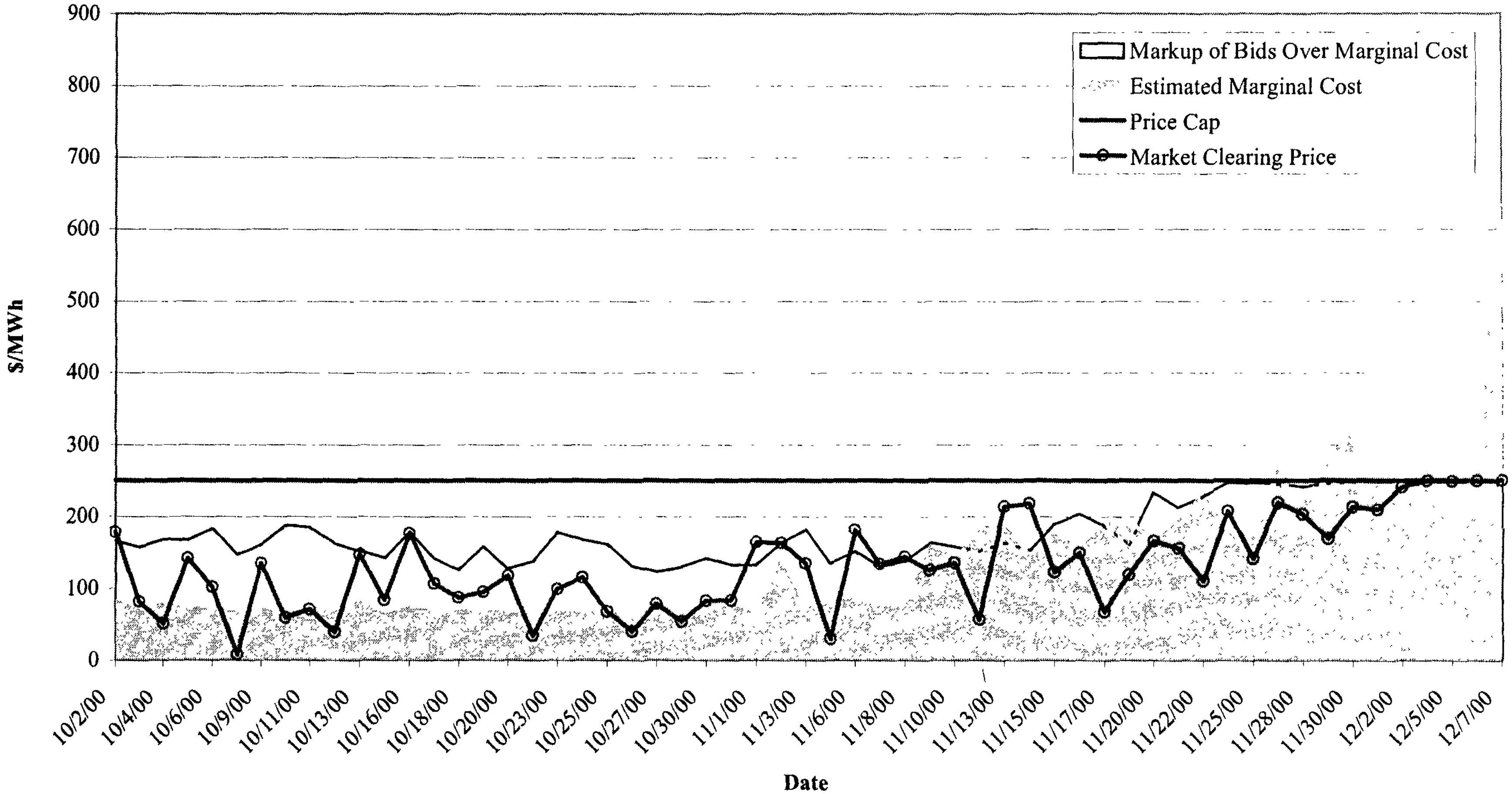
[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

[3]: Market clearing prices provided by ISO in response to CAAG subpoenas (received via waiver). Market clearing prices are 10-minute incremental prices averaged over hours and then over days. Daily average market clearing prices are weighted by real-time demand.

[4]: The dotted line represents the markup of bids over marginal cost when the markup is less than estimated marginal cost.

Appendix PQH-H
Dynegy/Electric Clearinghouse
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
10/2/00 - 12/7/00



Notes and Sources:

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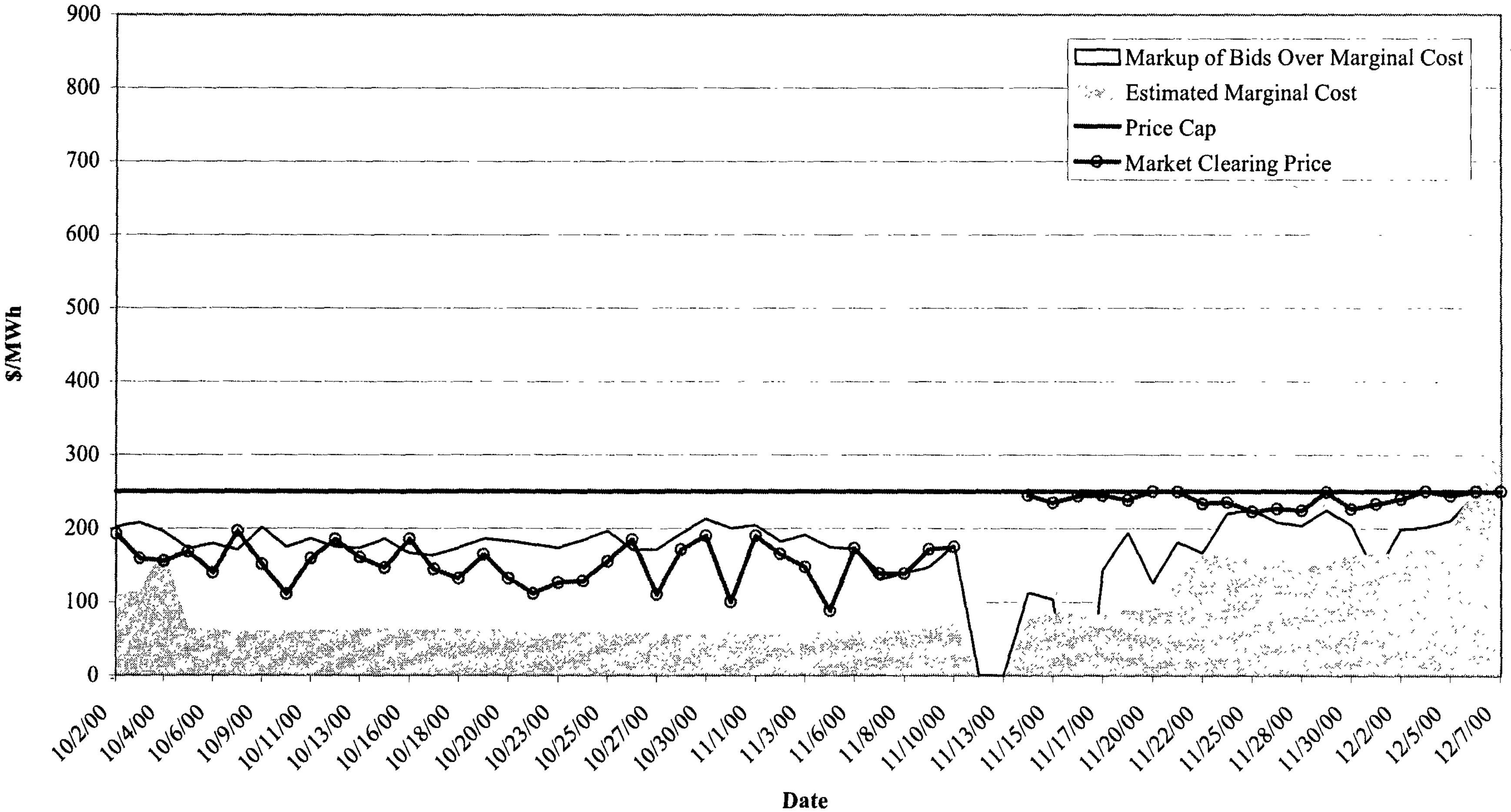
[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

[3]: Market clearing prices provided by ISO in response to CAAG subpoenas (received via waiver). Market clearing prices are 10-minute incremental prices averaged over hours and then over days. Daily average market clearing prices are weighted by real-time demand.

[4]: The dotted line represents the markup of bids over marginal cost when the markup is less than estimated marginal cost.

Appendix PQH-H
Mirant/Southern Company Energy Marketing, L.P.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
10/2/00 - 12/7/00



Notes and Sources:

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[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

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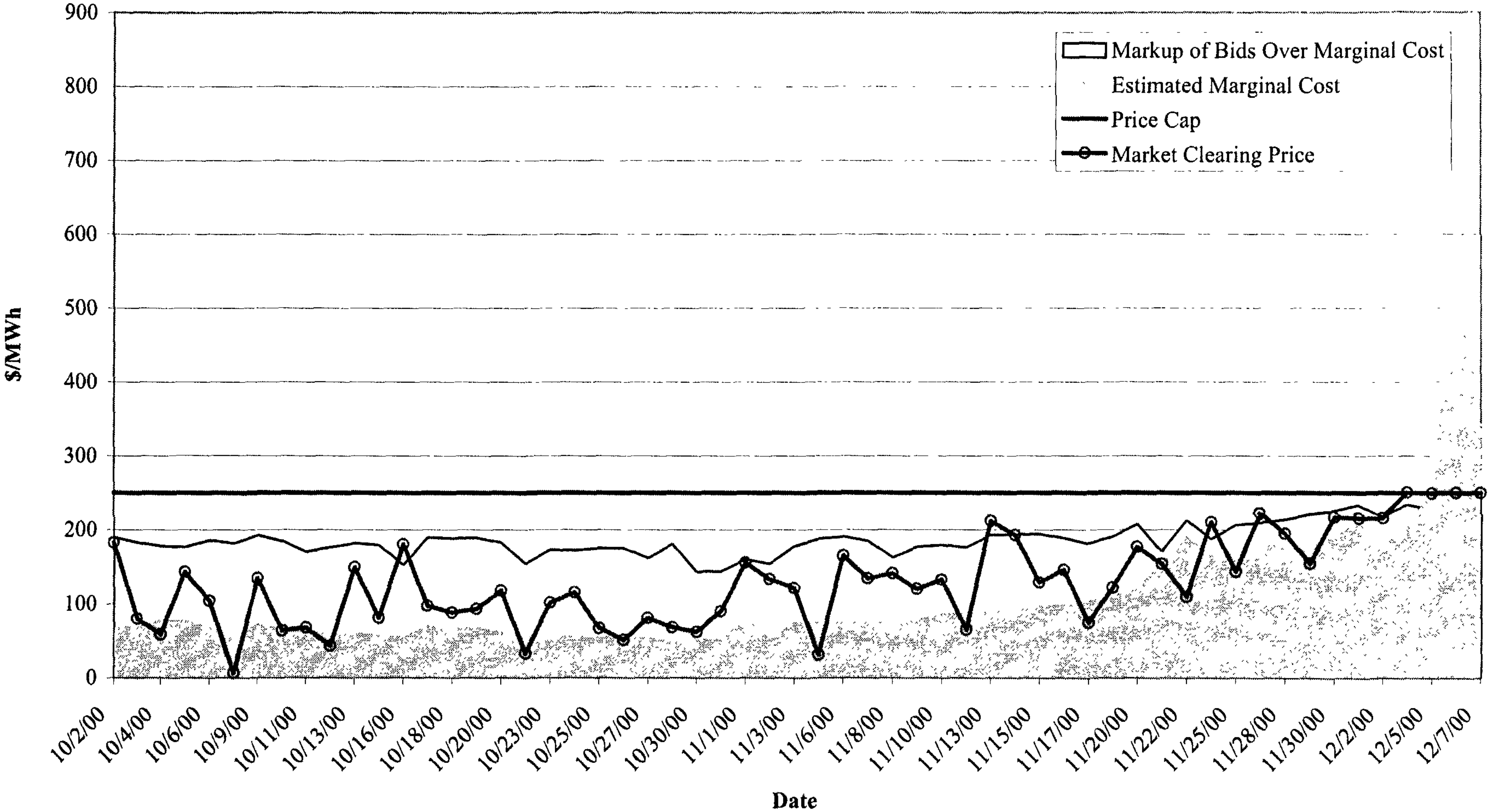
[4]: Market clearing price is not calculated where there is no bid.

Appendix PQH-H
Reliant Energy Services, Inc.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
10/2/00 - 12/7/00



Notes and Sources:

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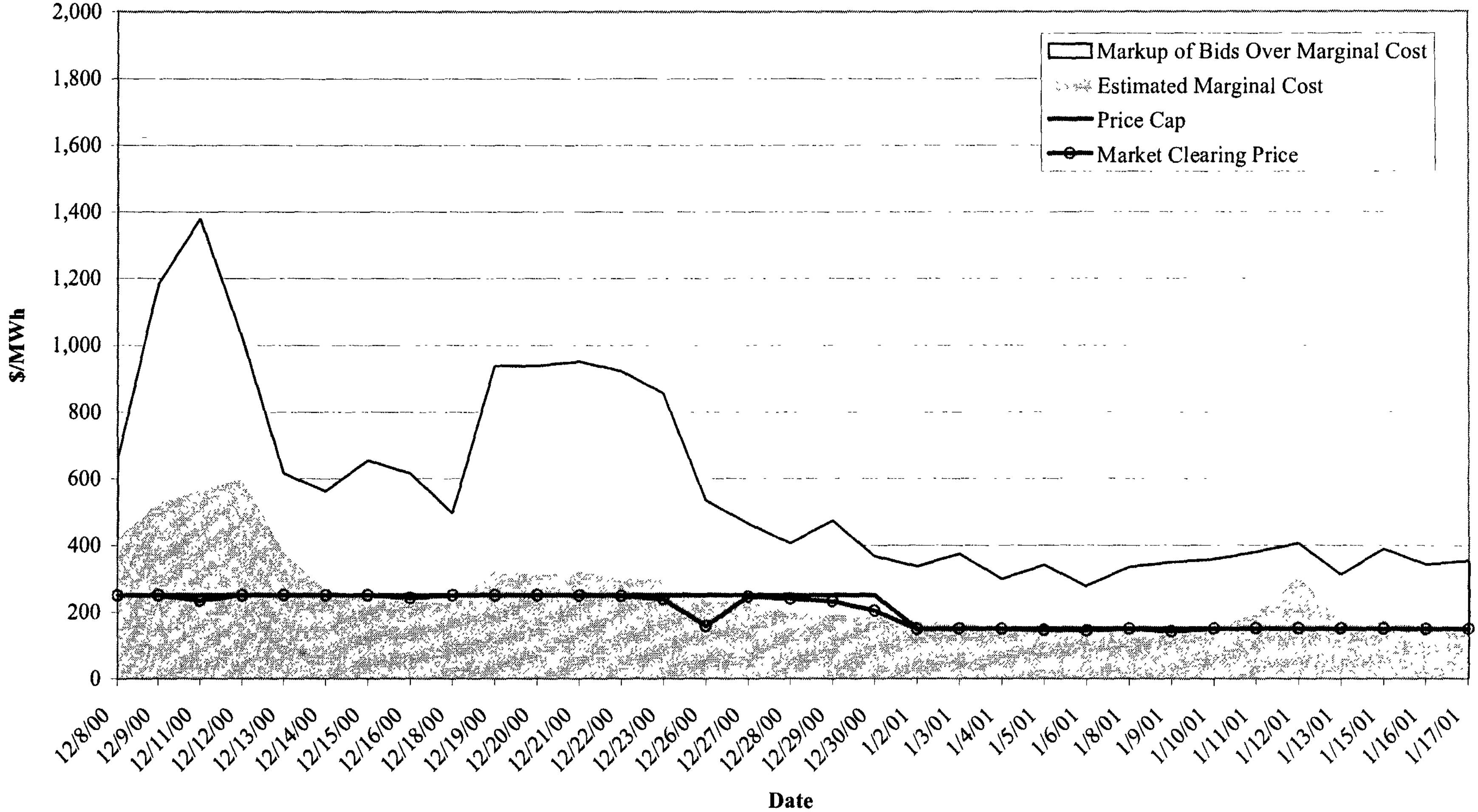
Appendix PQH-H
AES/Williams Energy Services Corporation
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
12/8/00 - 1/17/01



Notes and Sources:

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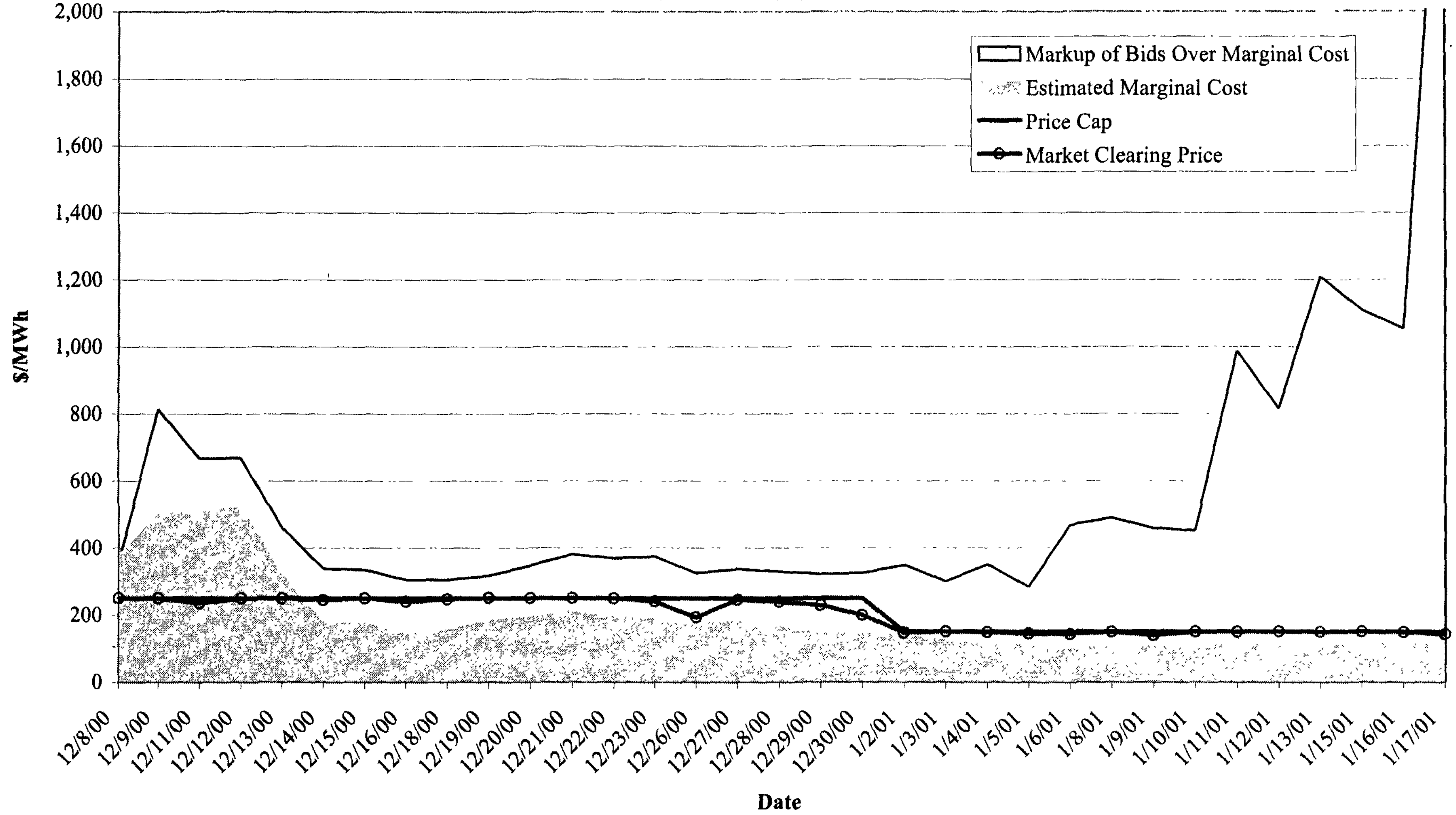
Appendix PQH-H
Duke Energy Trading and Marketing, L.L.C.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
12/8/00 - 1/17/01



Notes and Sources:

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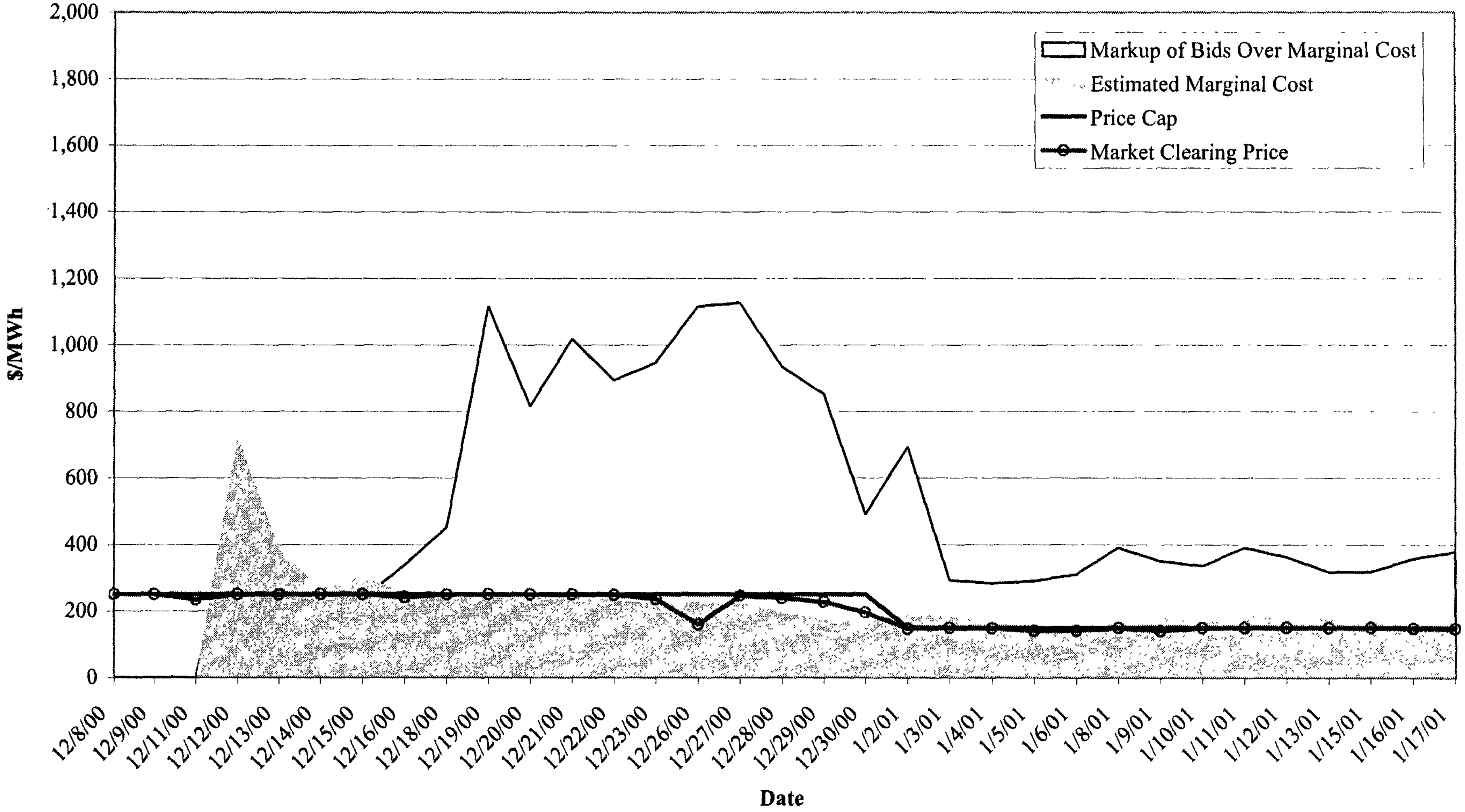
Appendix PQH-H
Dynegy/Electric Clearinghouse
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
12/8/00 - 1/17/01



Notes and Sources:

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[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs. Daily average marginal costs are weighted by MW bid.

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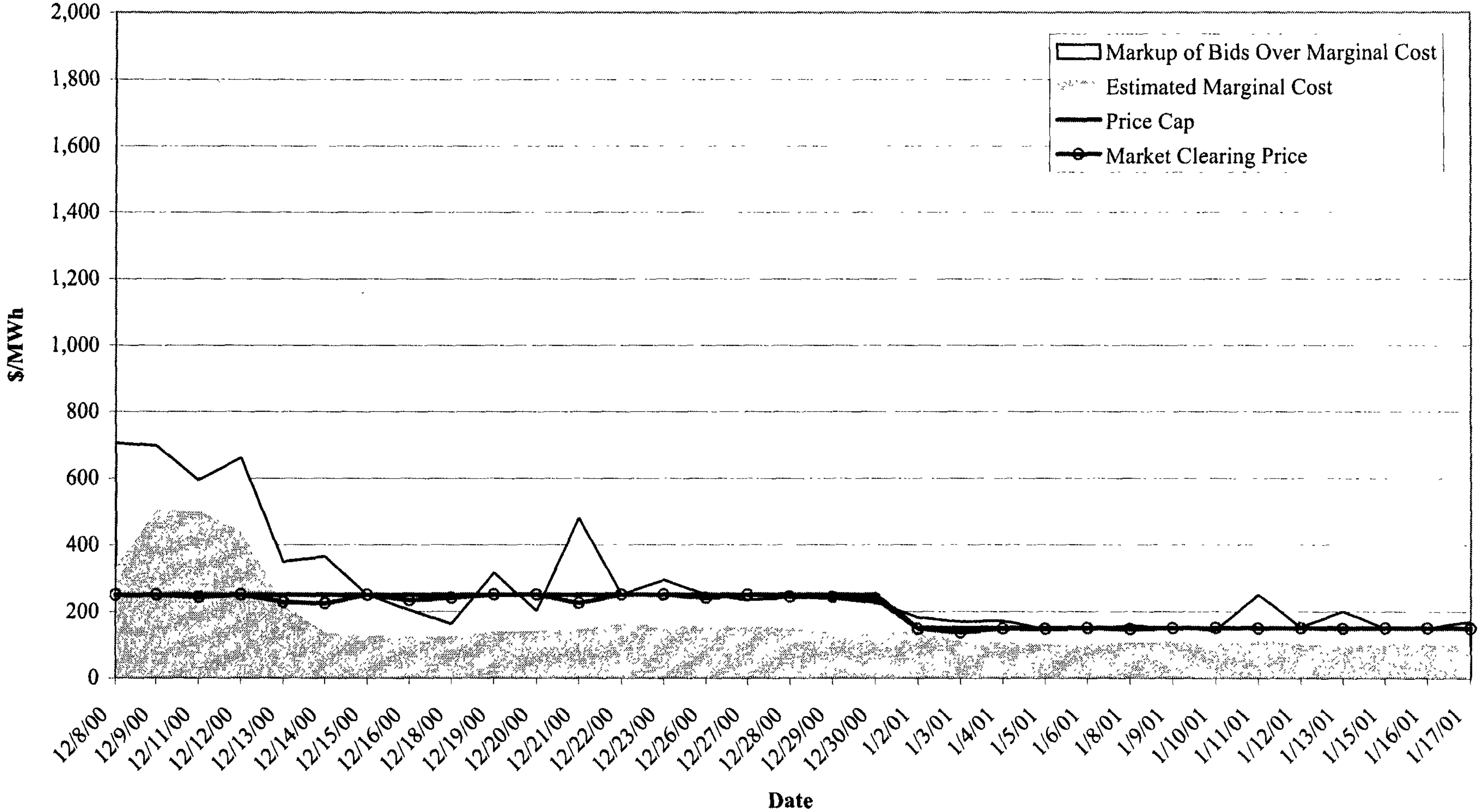
Appendix PQH-H
Mirant/Southern Company Energy Marketing, L.P.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
12/8/00 - 1/17/01



Notes and Sources:

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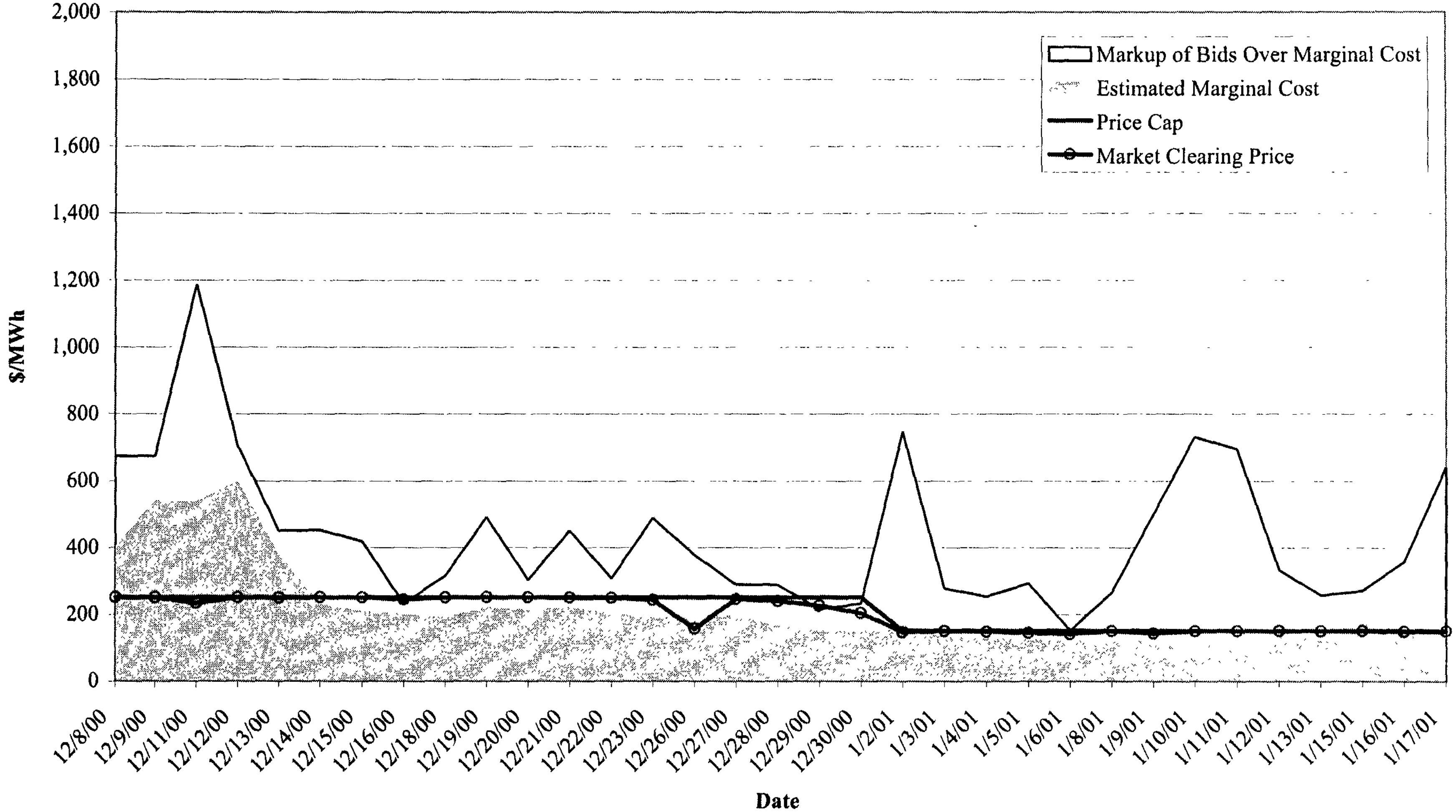
Appendix PQH-H
Reliant Energy Services, Inc.
Daily MW-Weighted Bid Price vs. Marginal Cost for On-Peak Hours
12/8/00 - 1/17/01



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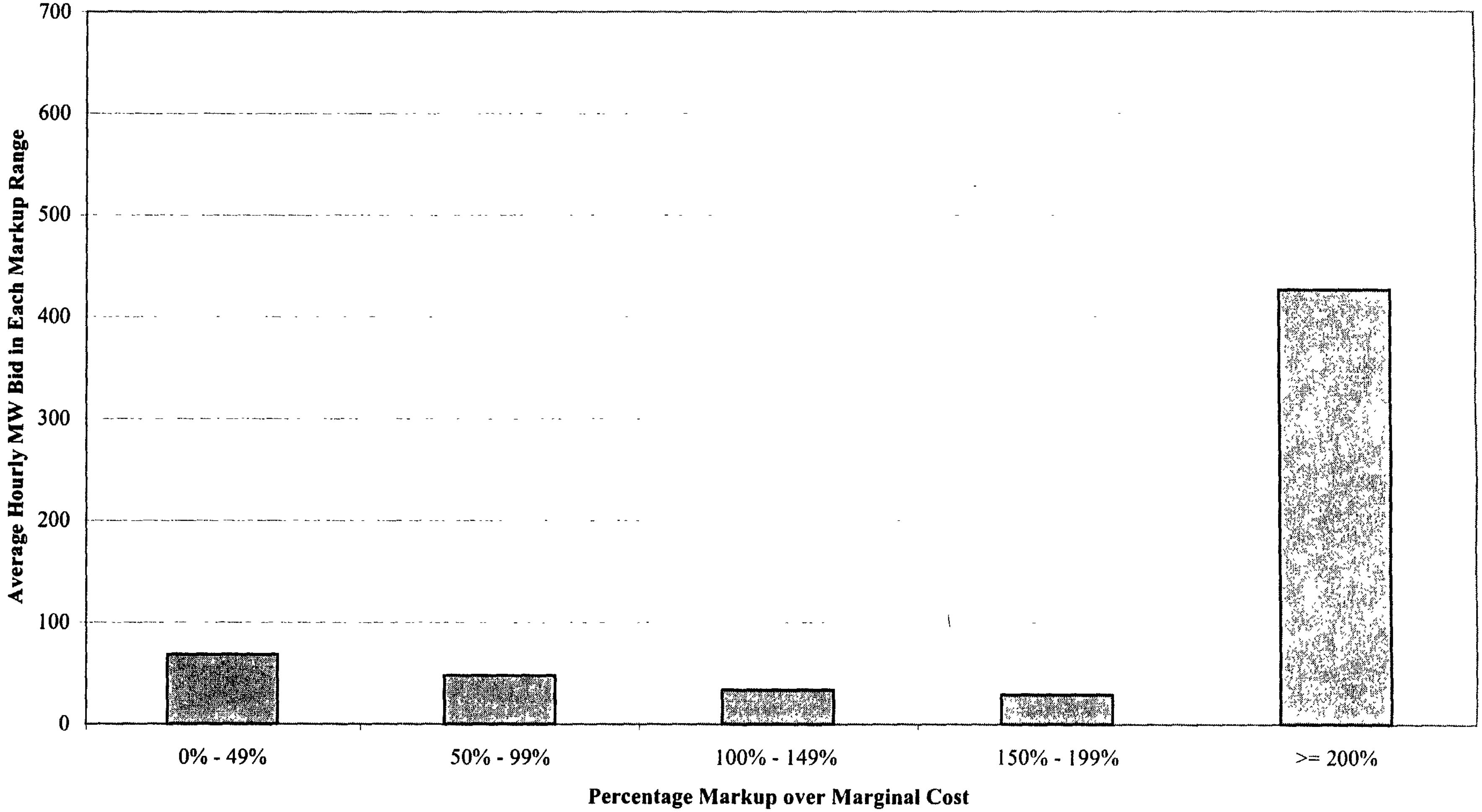
Appendix PQH-I
AES/Williams Energy Services Corporation
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
1/1/00 - 4/30/00



Sources:

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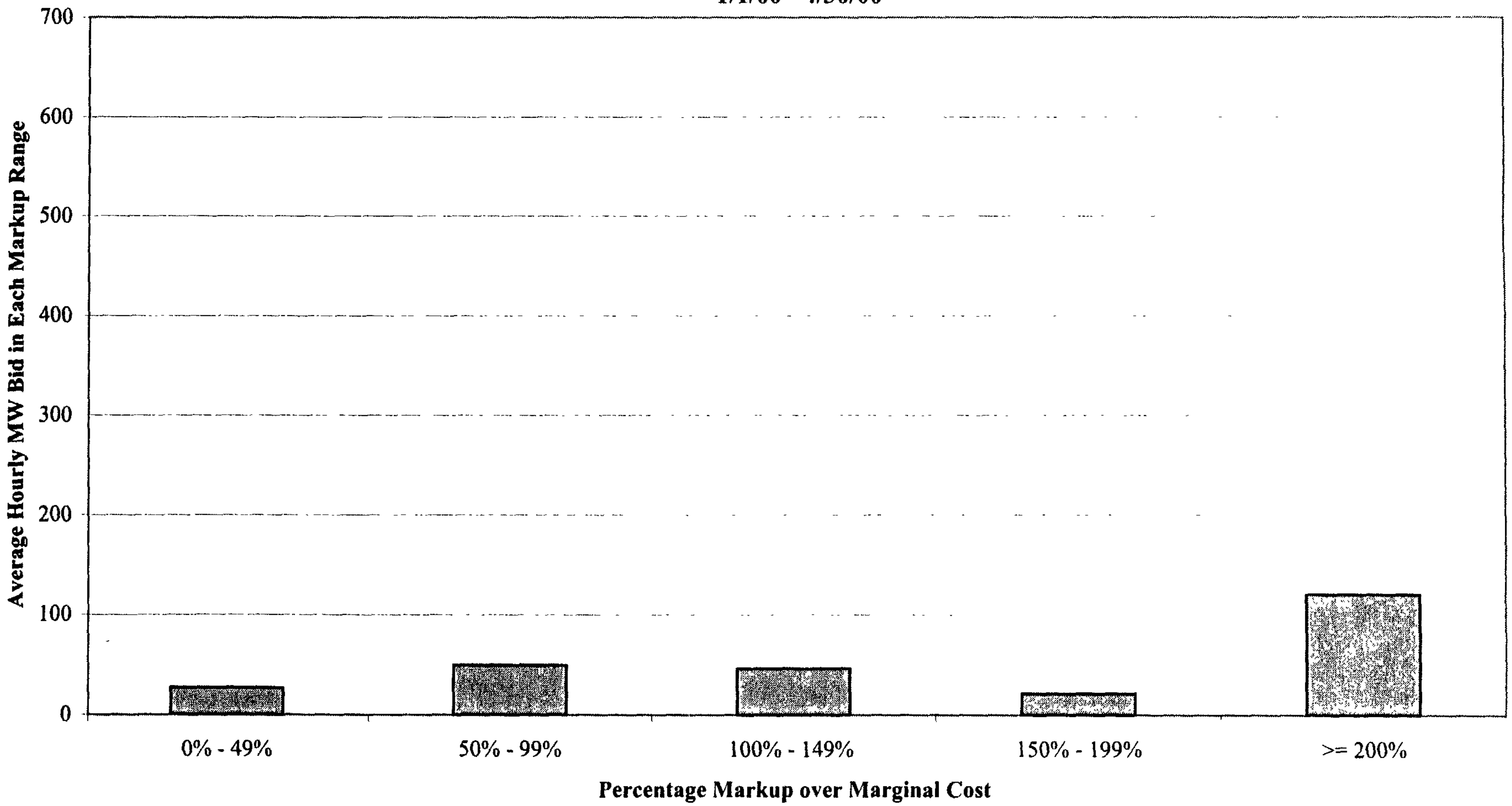
[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Duke Energy Trading and Marketing, L.L.C.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours

1/1/00 - 4/30/00



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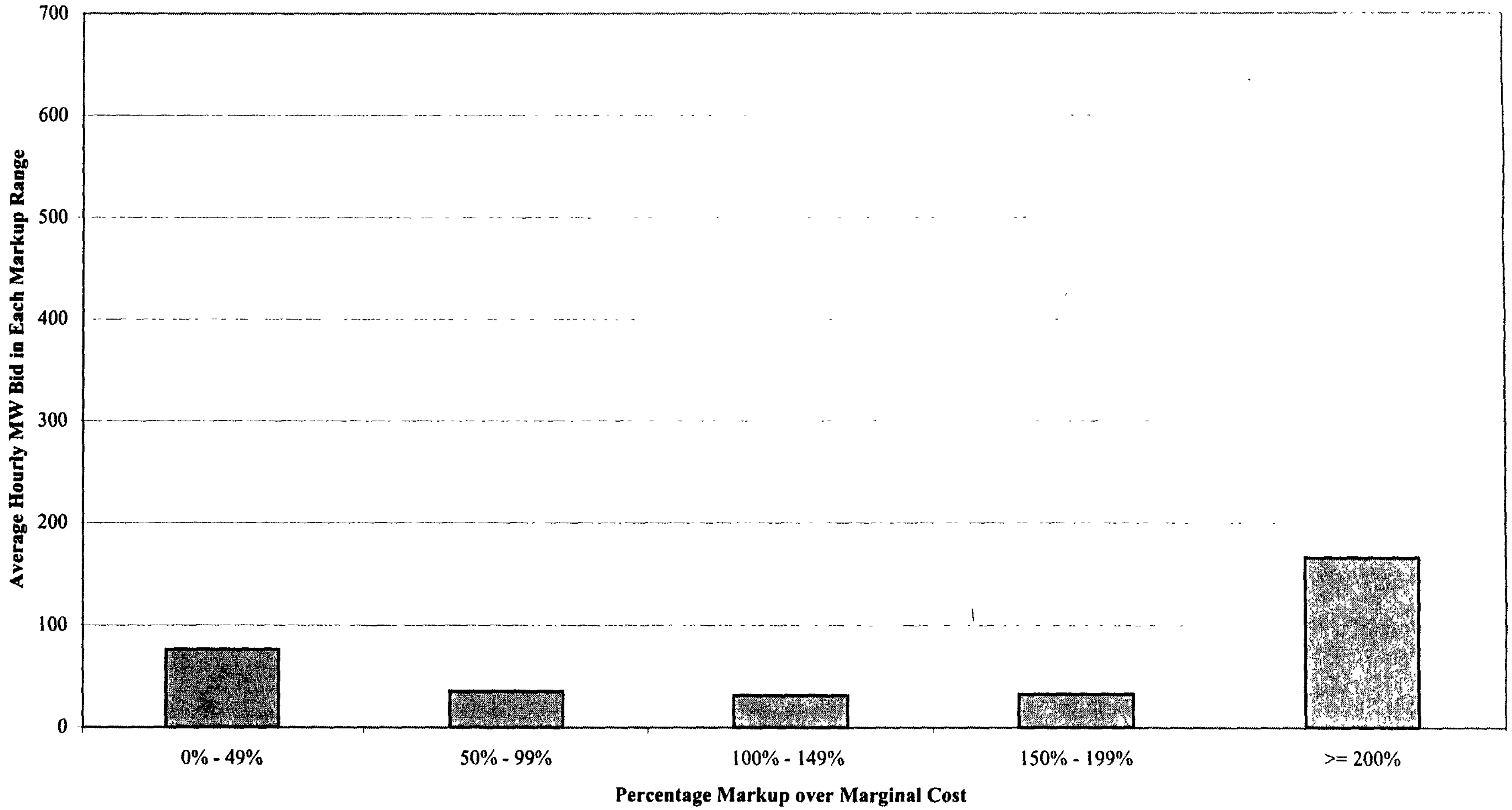
Appendix PQH-I
Dynegy/Electric Clearinghouse
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
1/1/00 - 4/30/00



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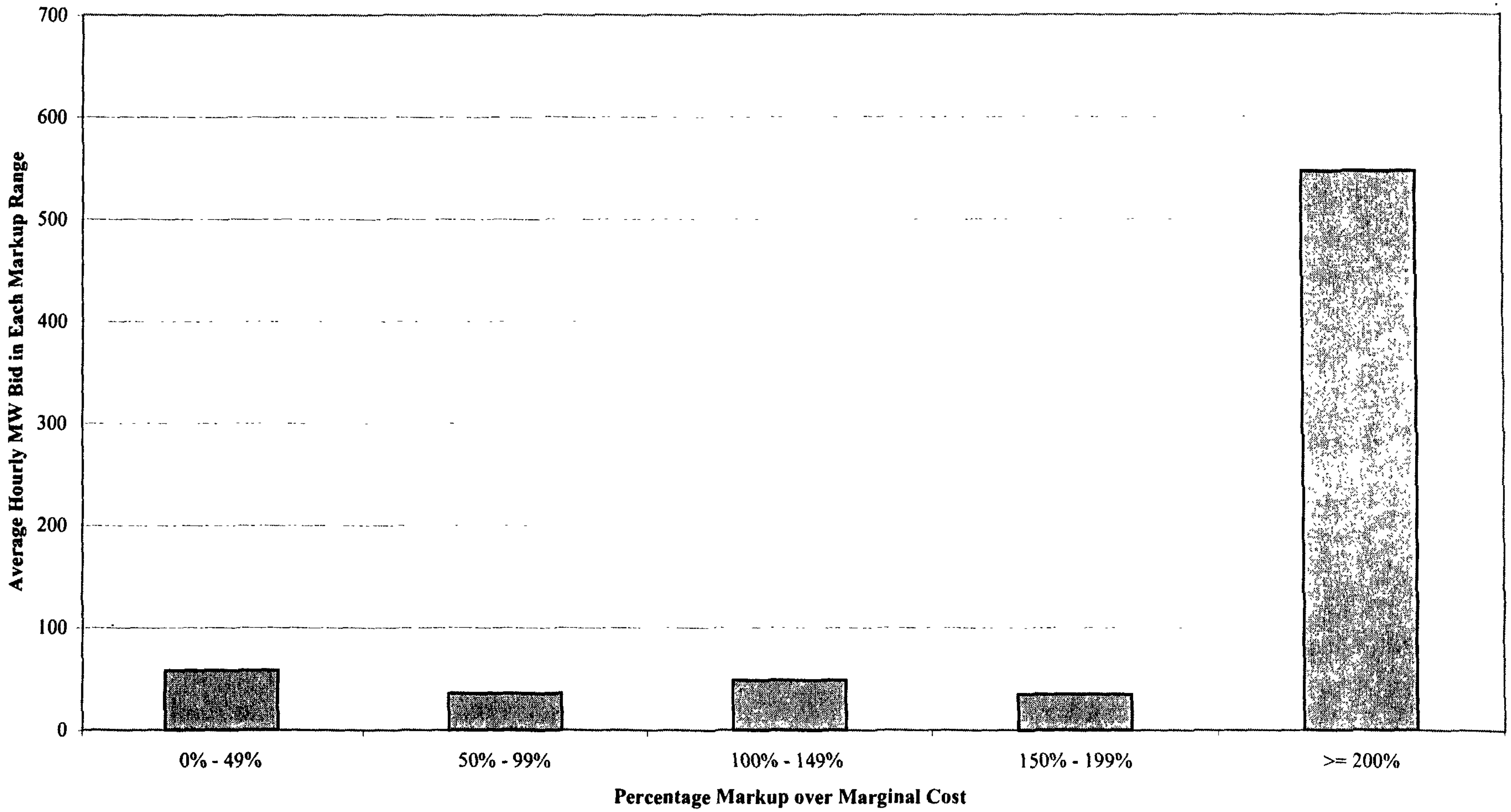
Appendix PQH-I
Mirant/Southern Company Energy Marketing, L.P.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours

1/1/00 - 4/30/00



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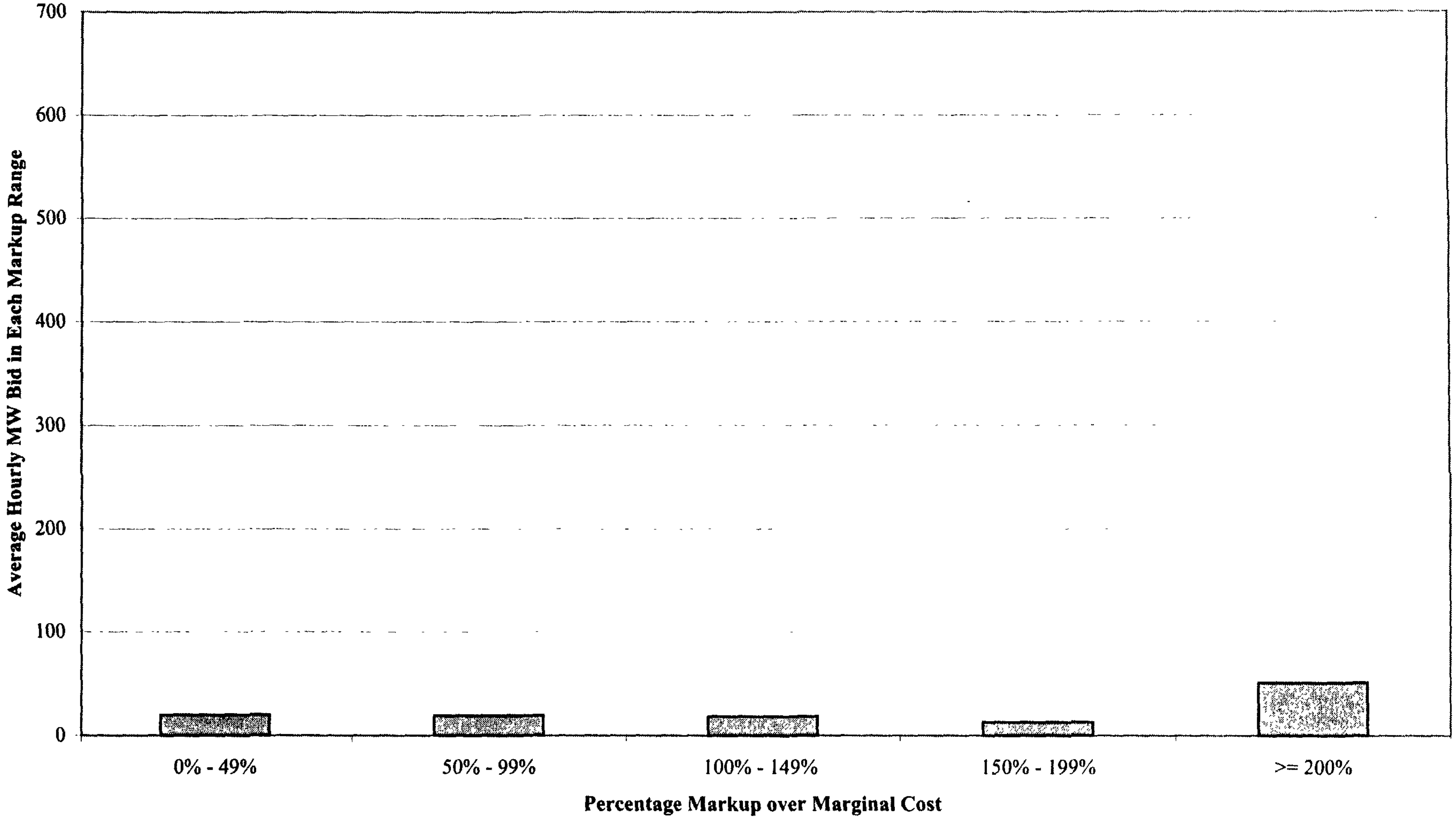
Appendix PQH-I
Reliant Energy Services, Inc.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
1/1/00 - 4/30/00



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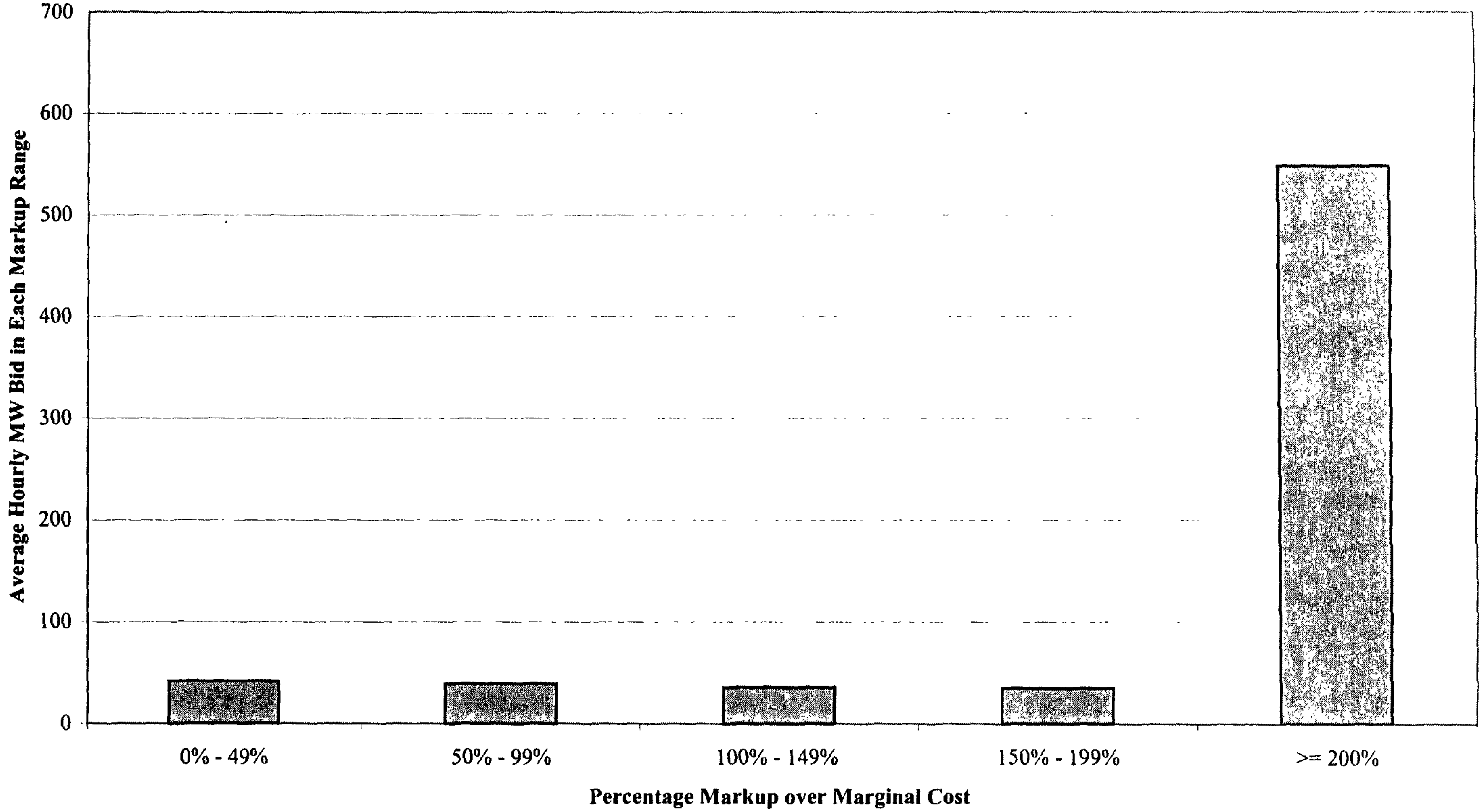
Appendix PQH-I
AES/Williams Energy Services Corporation
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
5/1/00 - 5/31/00



Sources:

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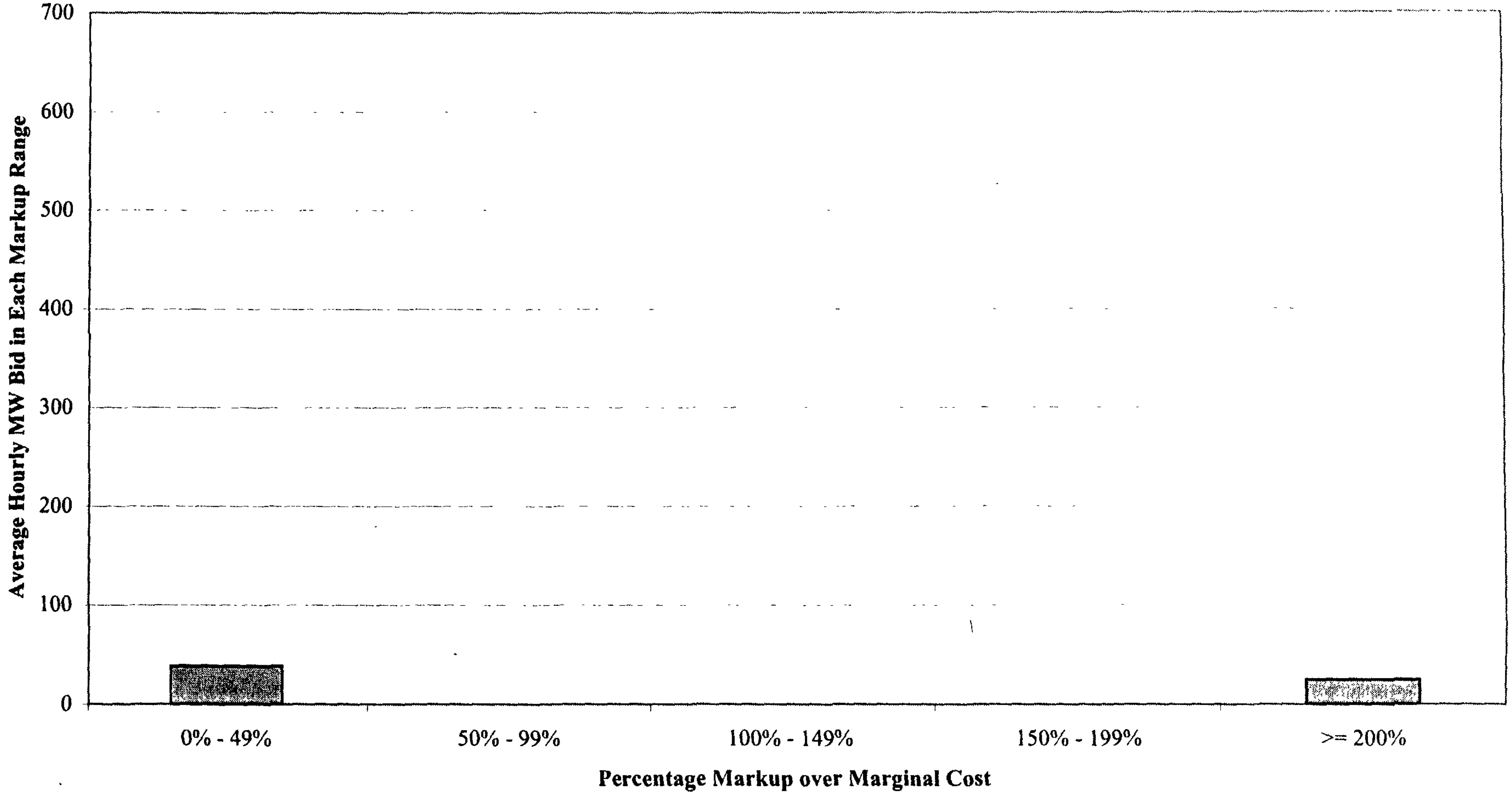
Appendix PQH-I
Duke Energy Trading and Marketing, L.L.C.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
5/1/00 - 5/31/00



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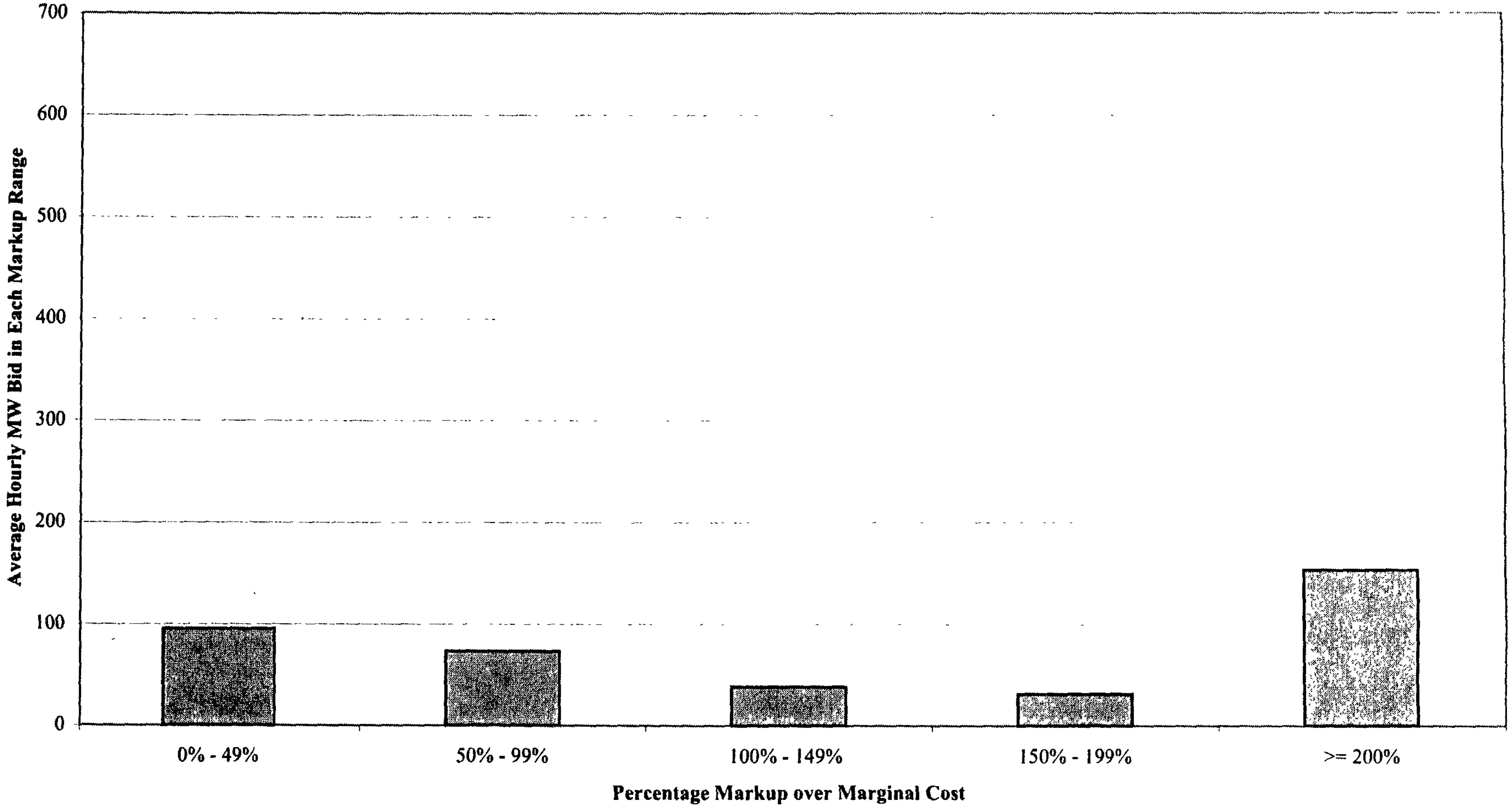
Appendix PQH-I
Dynegy/Electric Clearinghouse
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
5/1/00 - 5/31/00



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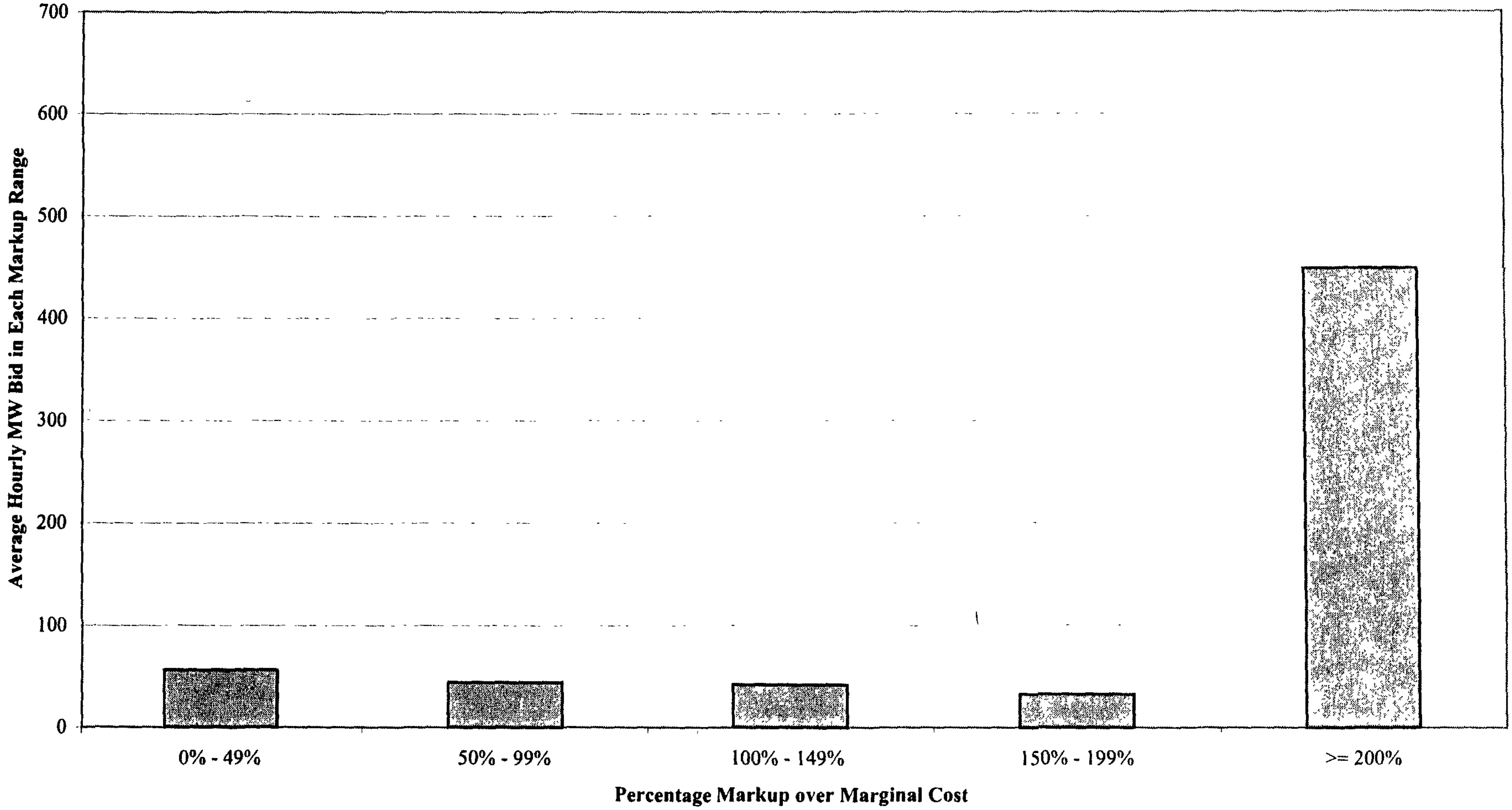
Appendix PQH-I
Mirant/Southern Company Energy Marketing, L.P.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
5/1/00 - 5/31/00



Sources:

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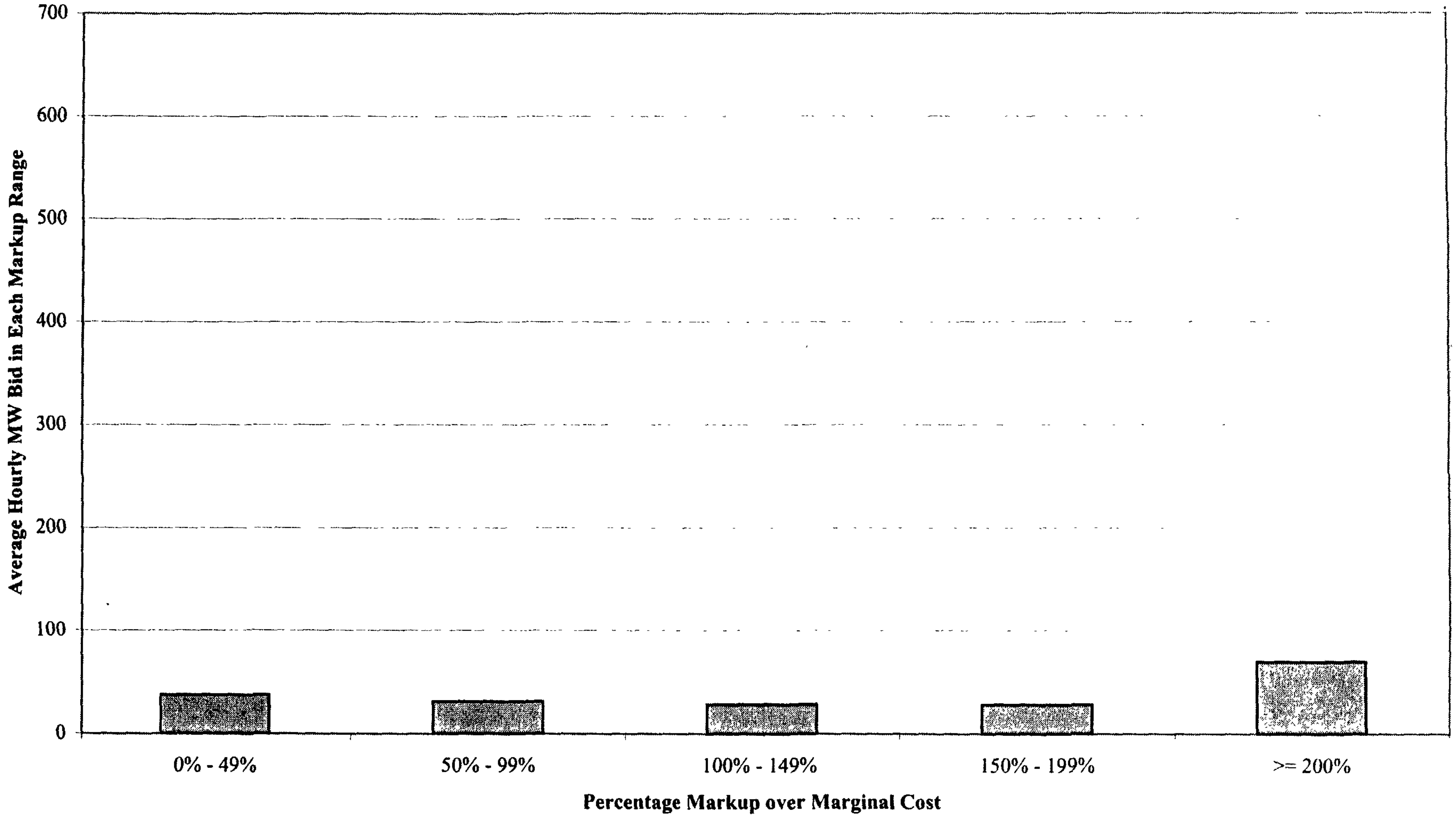
Appendix PQH-I
Reliant Energy Services, Inc.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
5/1/00 - 5/31/00



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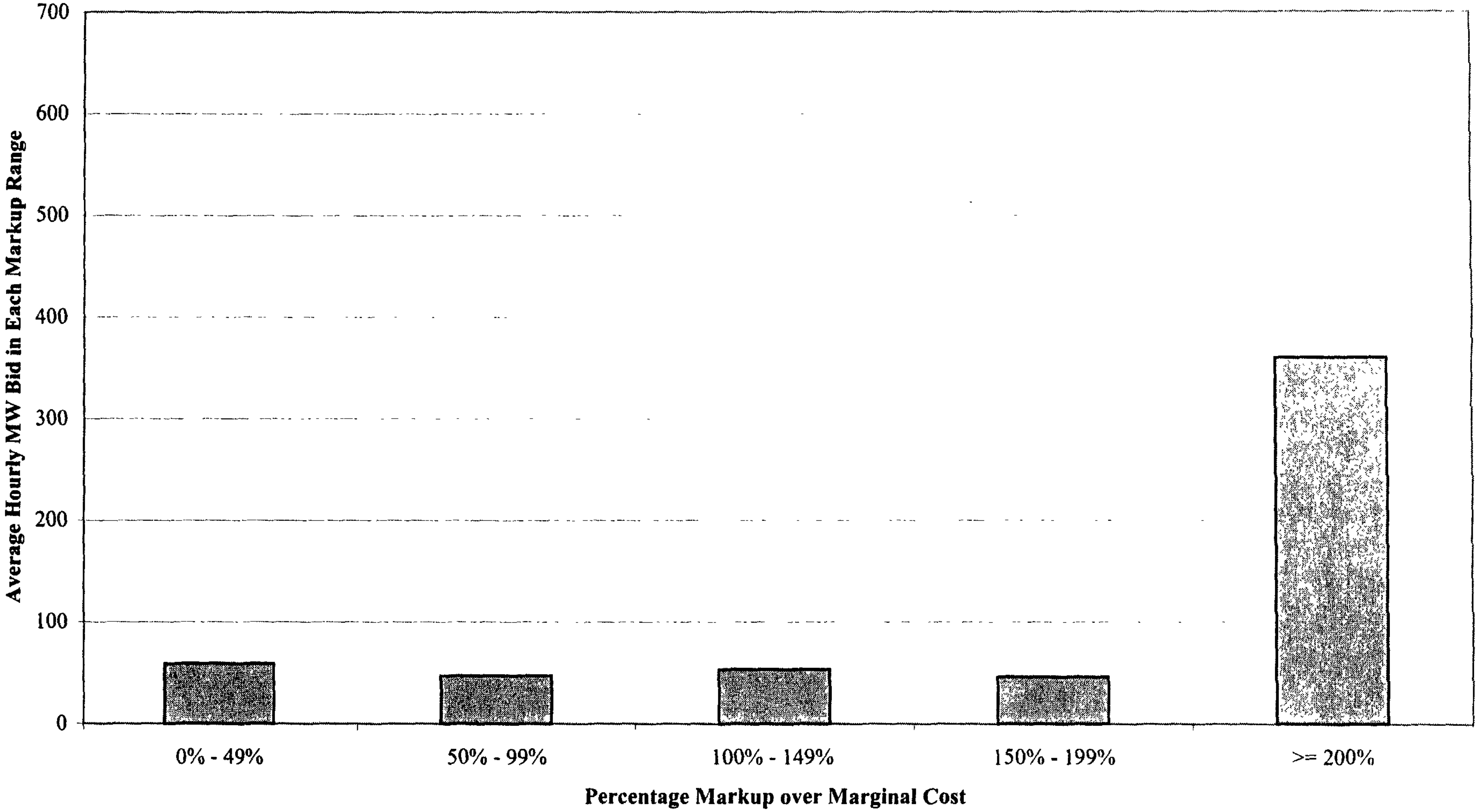
Appendix PQH-I
AES/Williams Energy Services Corporation
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
6/1/00 - 6/30/00



Sources:

[1]: Bid data from CAISO BEEP Stack data.

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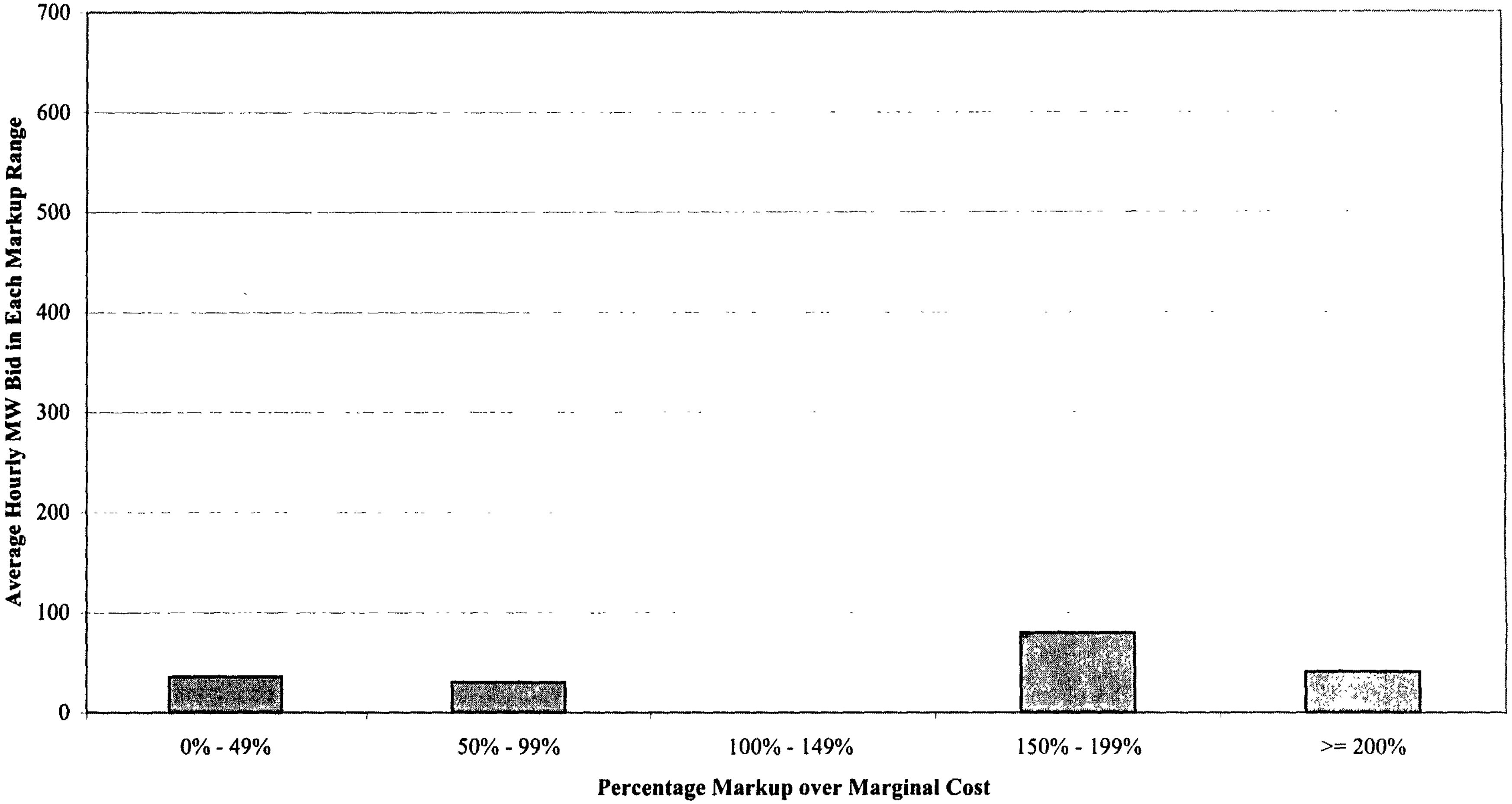
Appendix PQH-I
Duke Energy Trading and Marketing, L.L.C.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
6/1/00 - 6/30/00



Sources:

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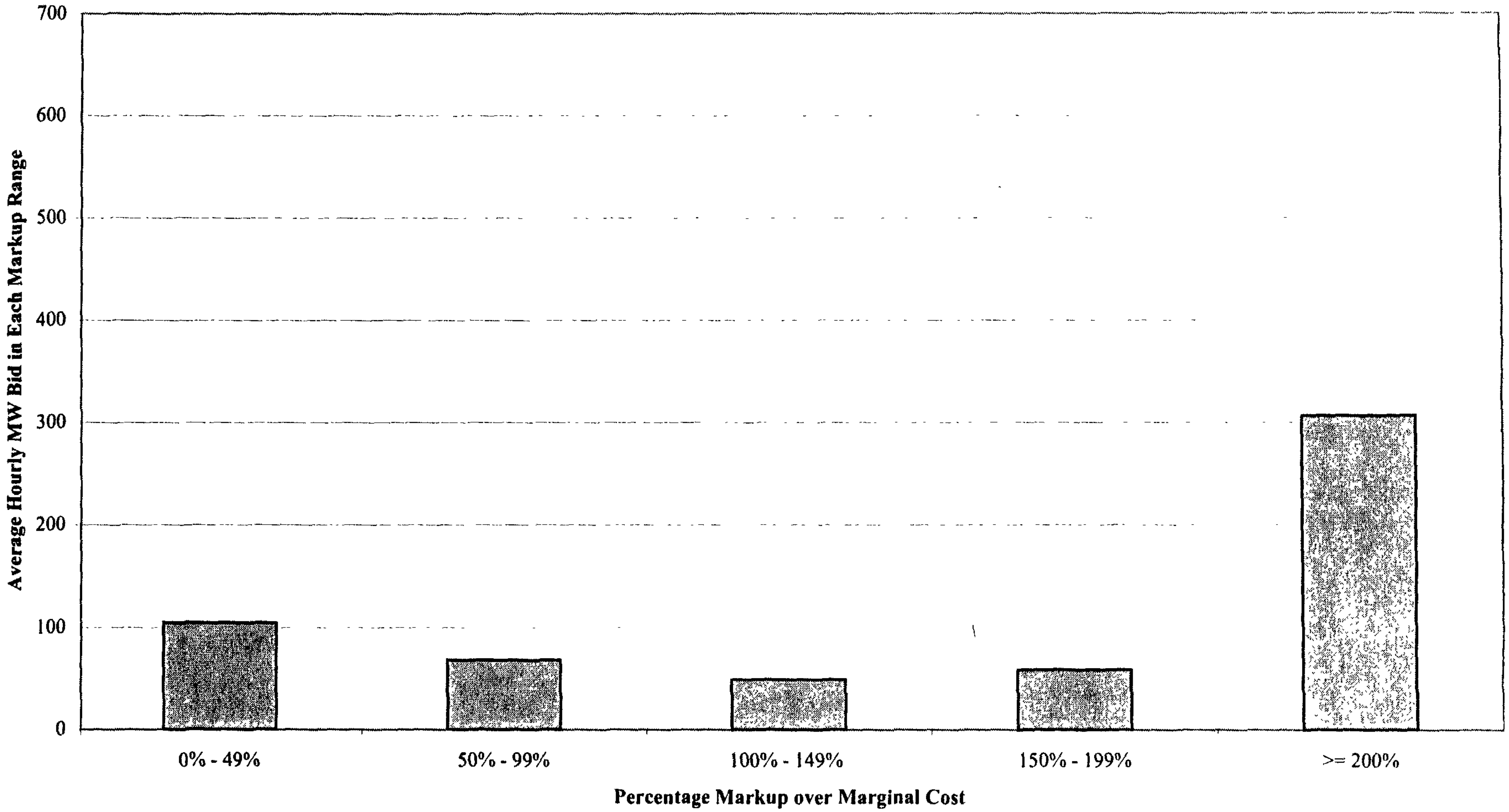
Appendix PQH-I
Dynegy/Electric Clearinghouse
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
6/1/00 - 6/30/00



Sources:

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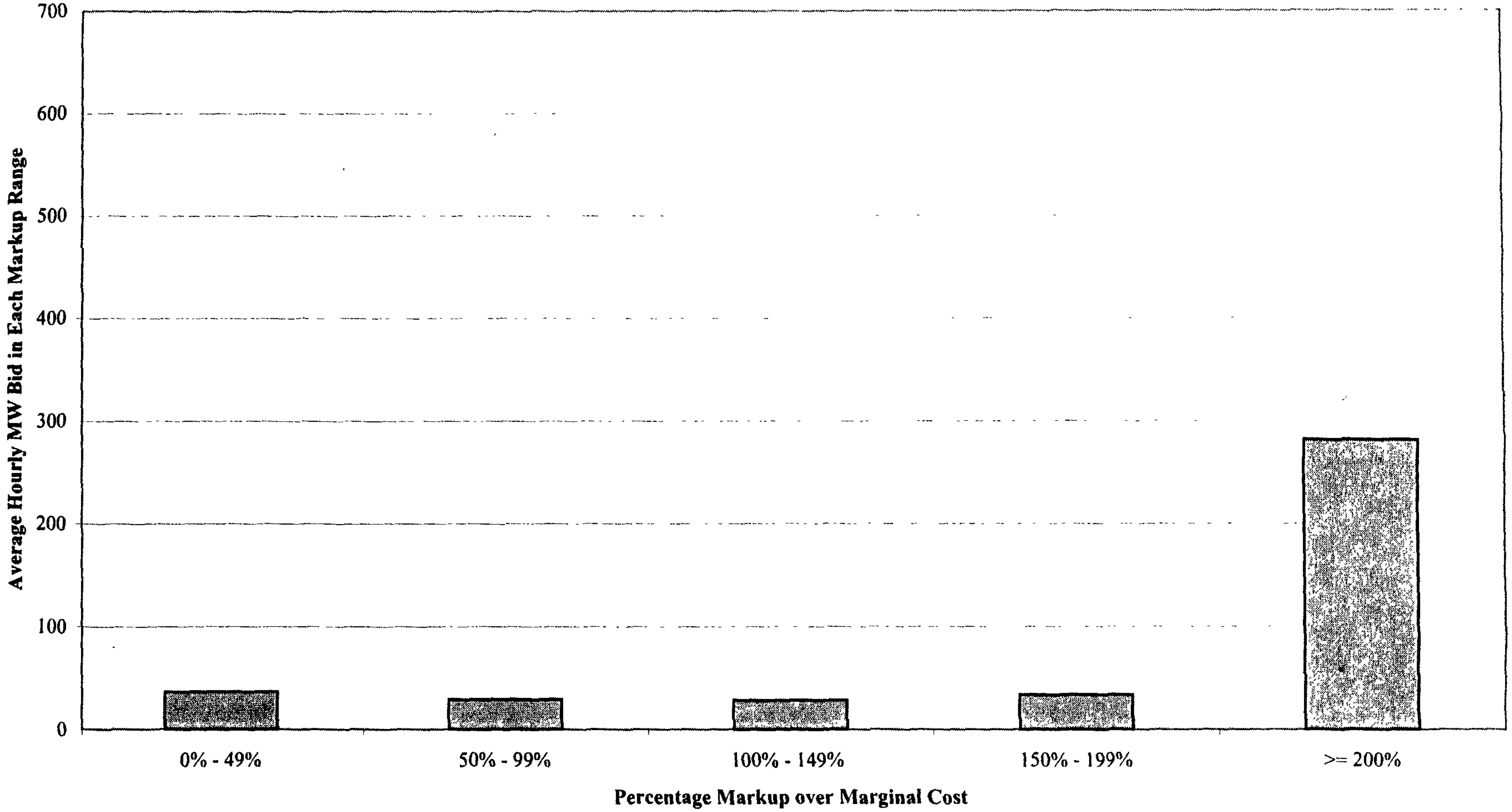
Appendix PQH-I
Mirant/Southern Company Energy Marketing, L.P.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
6/1/00 - 6/30/00



Sources:
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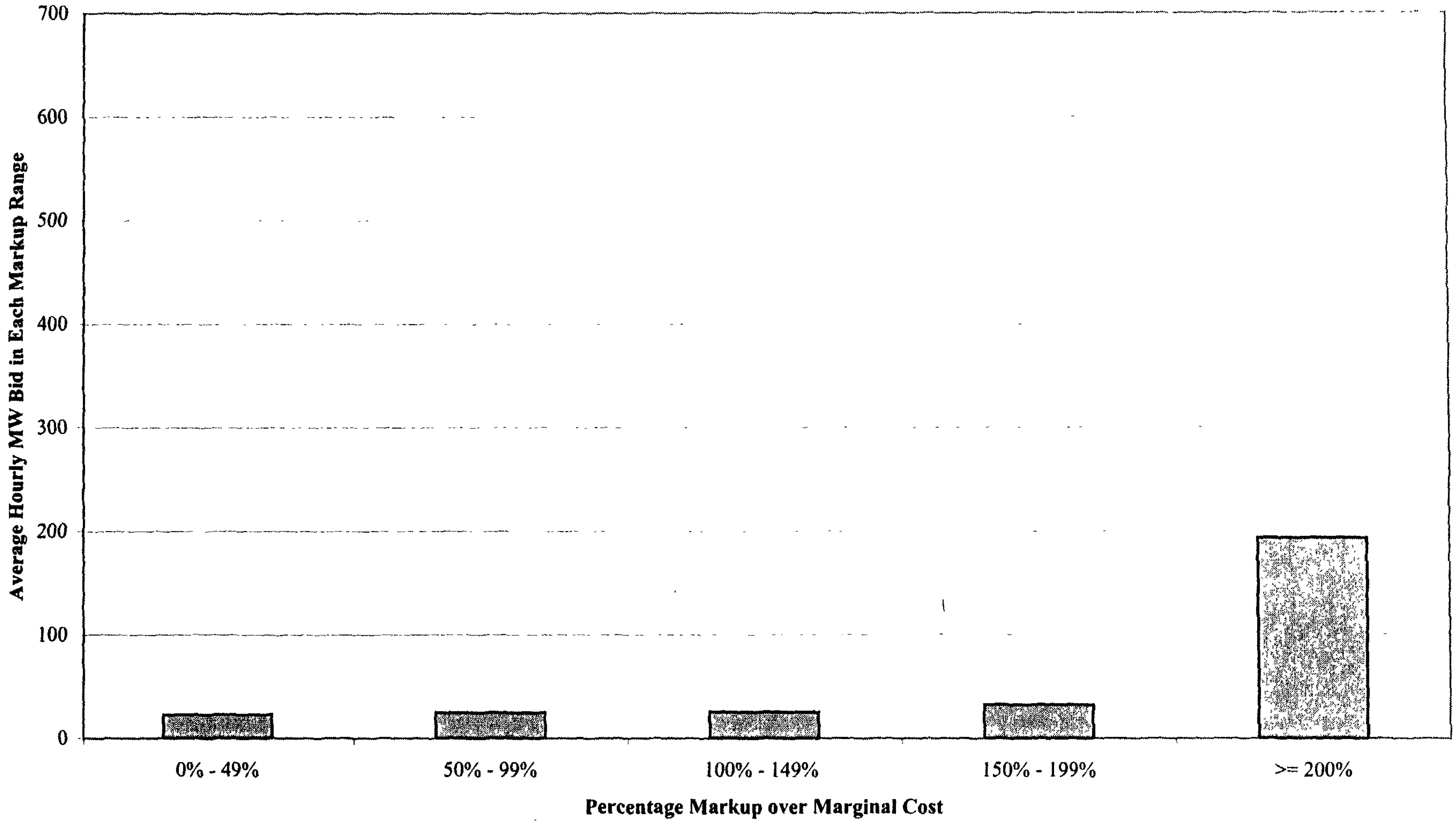
Appendix PQH-1
Reliant Energy Services, Inc.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
6/1/00 - 6/30/00



Sources:
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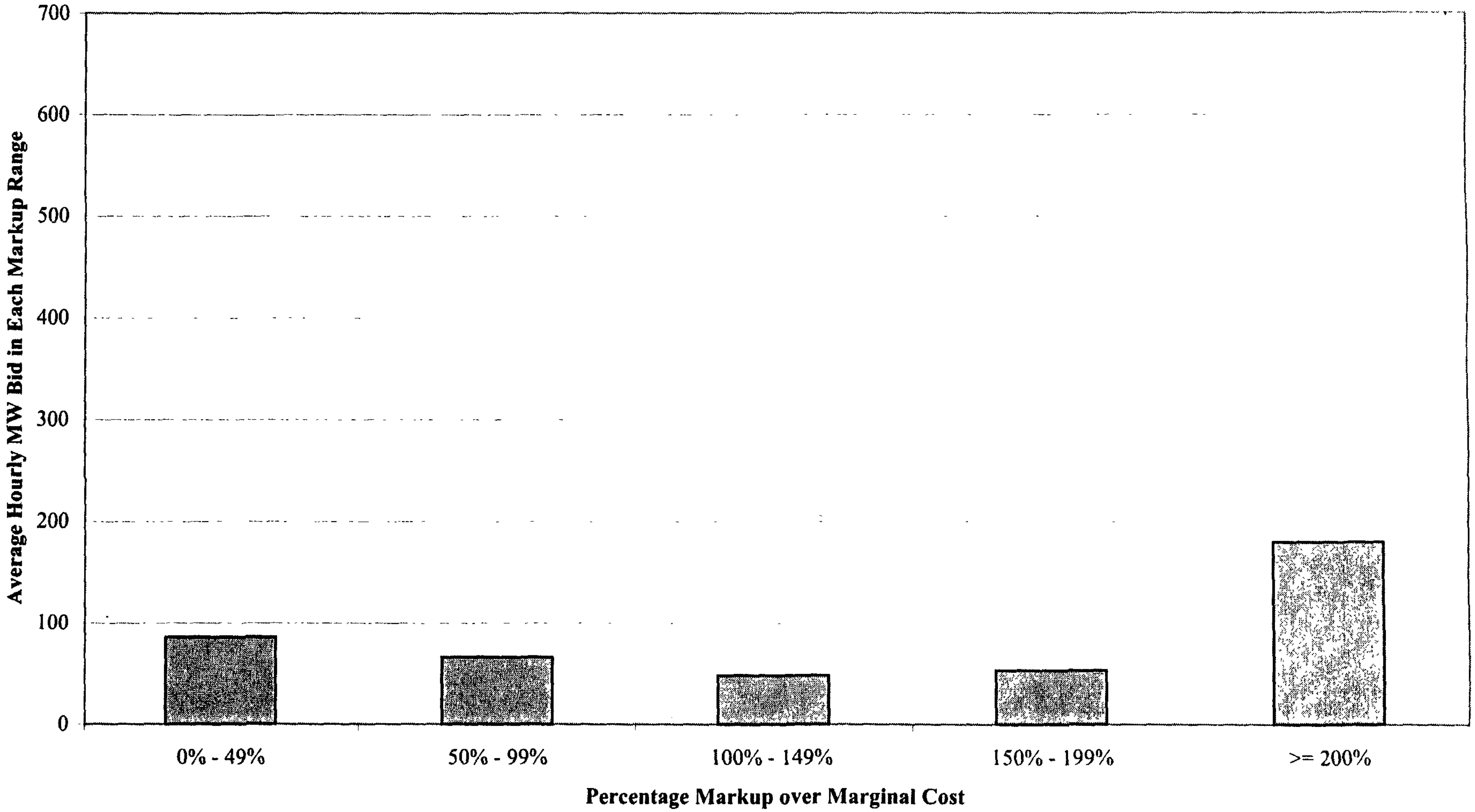
Appendix PQH-I
AES/Williams Energy Services Corporation
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
7/1/00 - 8/6/00



Sources:

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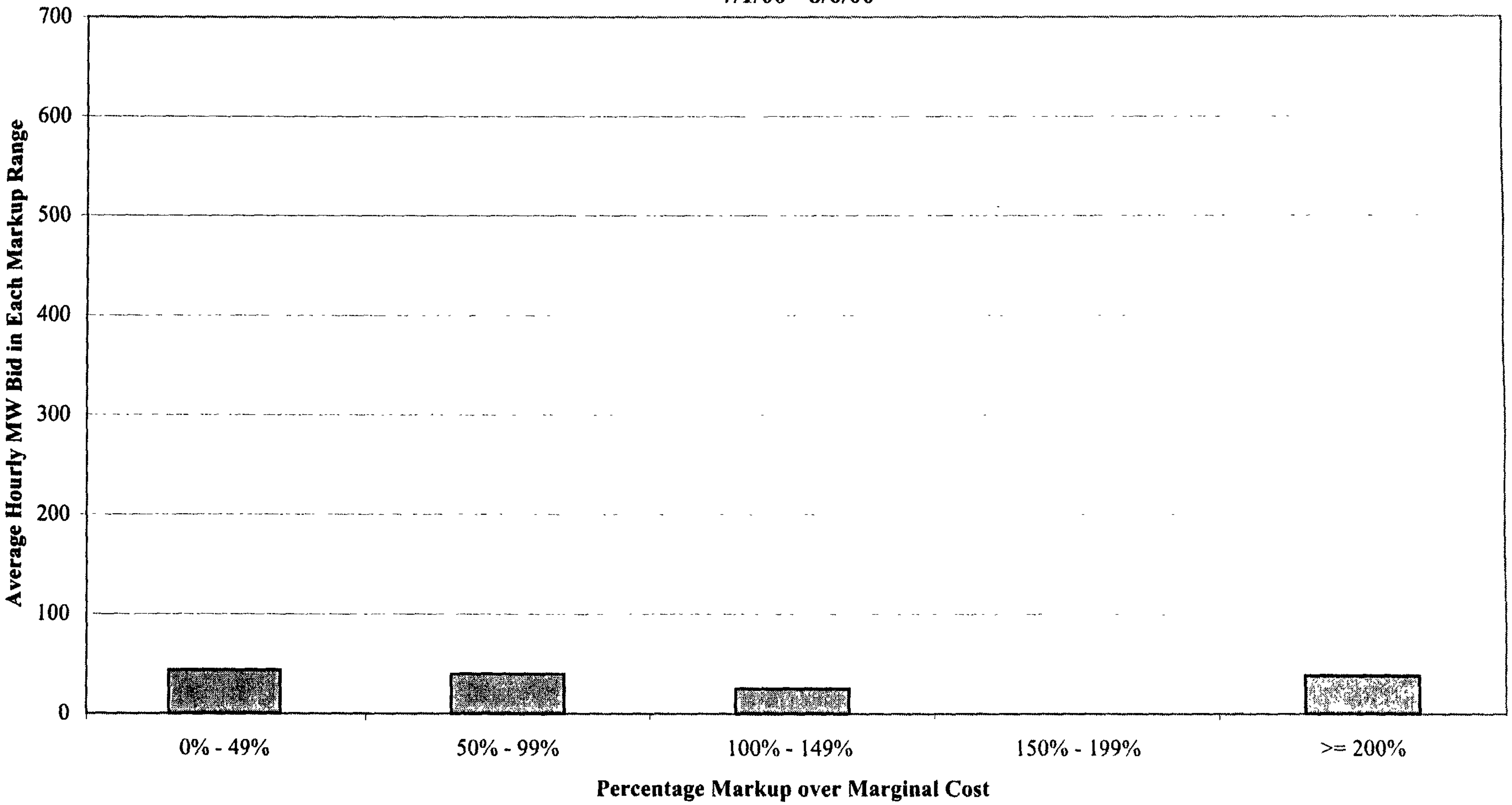
Appendix PQH-I
Duke Energy Trading and Marketing, L.L.C.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
7/1/00 - 8/6/00



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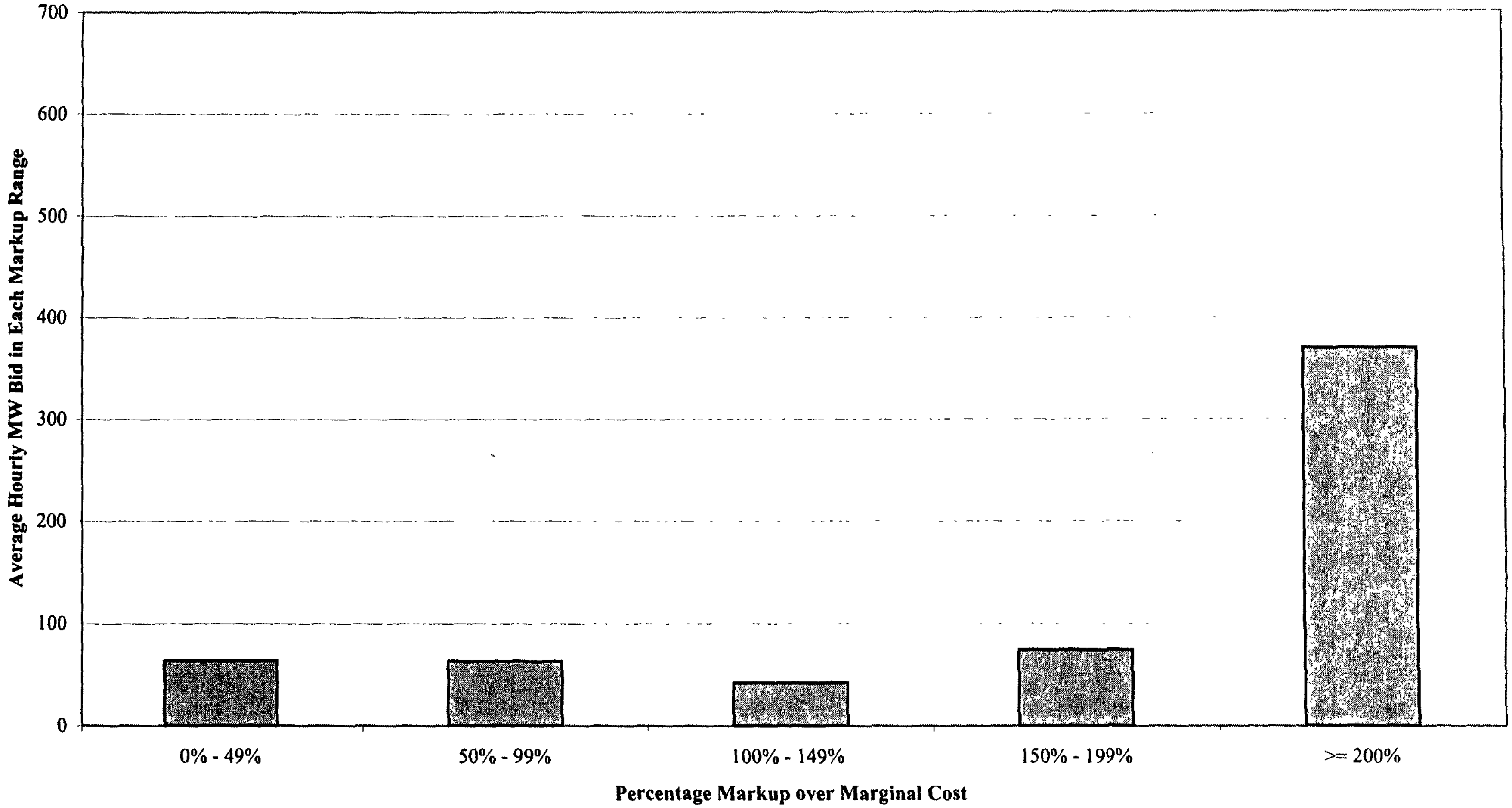
Appendix PQH-I
Dynegy/Electric Clearinghouse
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
7/1/00 - 8/6/00



Sources:
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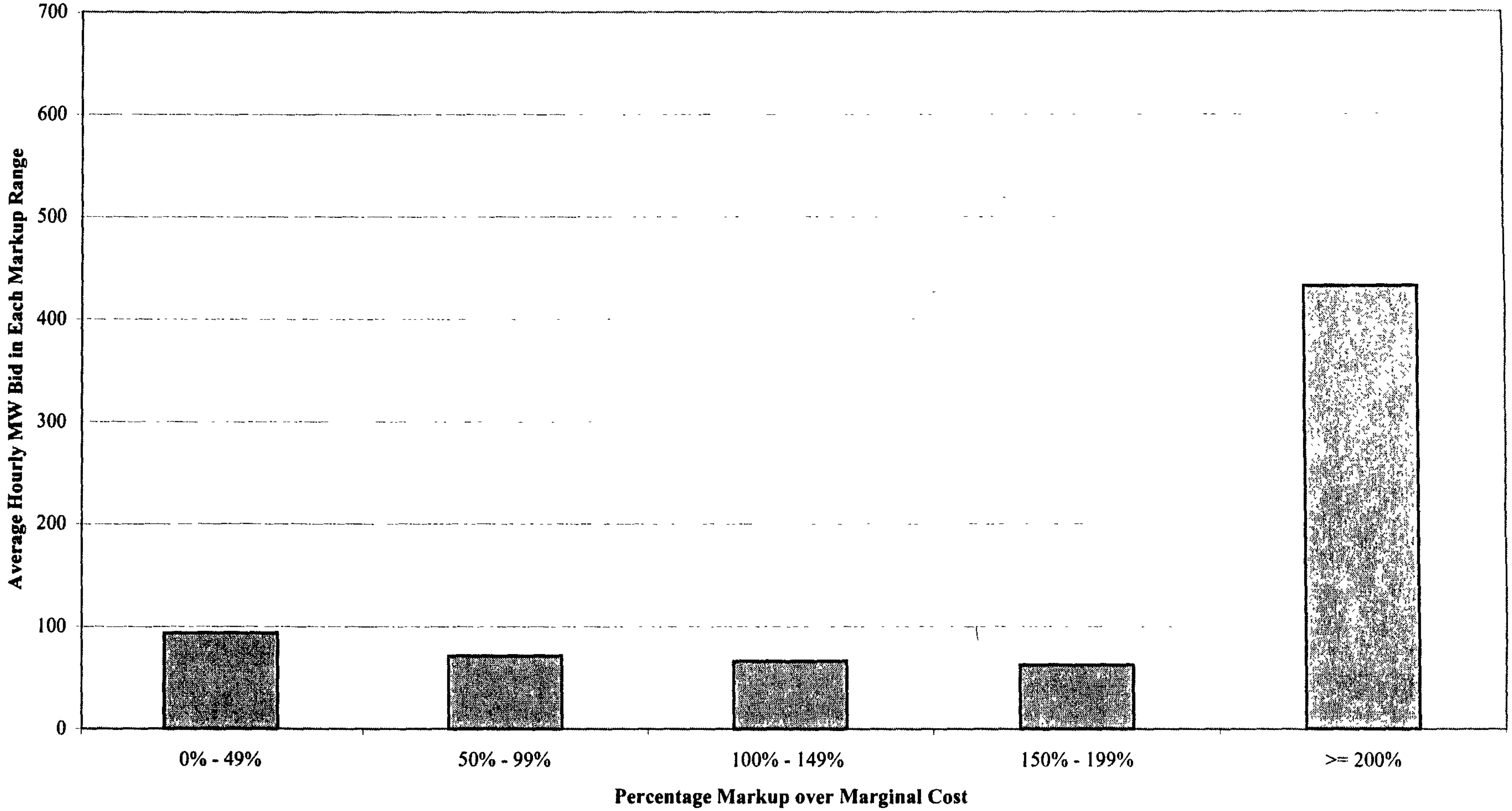
Appendix PQH-I
Mirant/Southern Company Energy Marketing, L.P.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
7/1/00 - 8/6/00



Sources:

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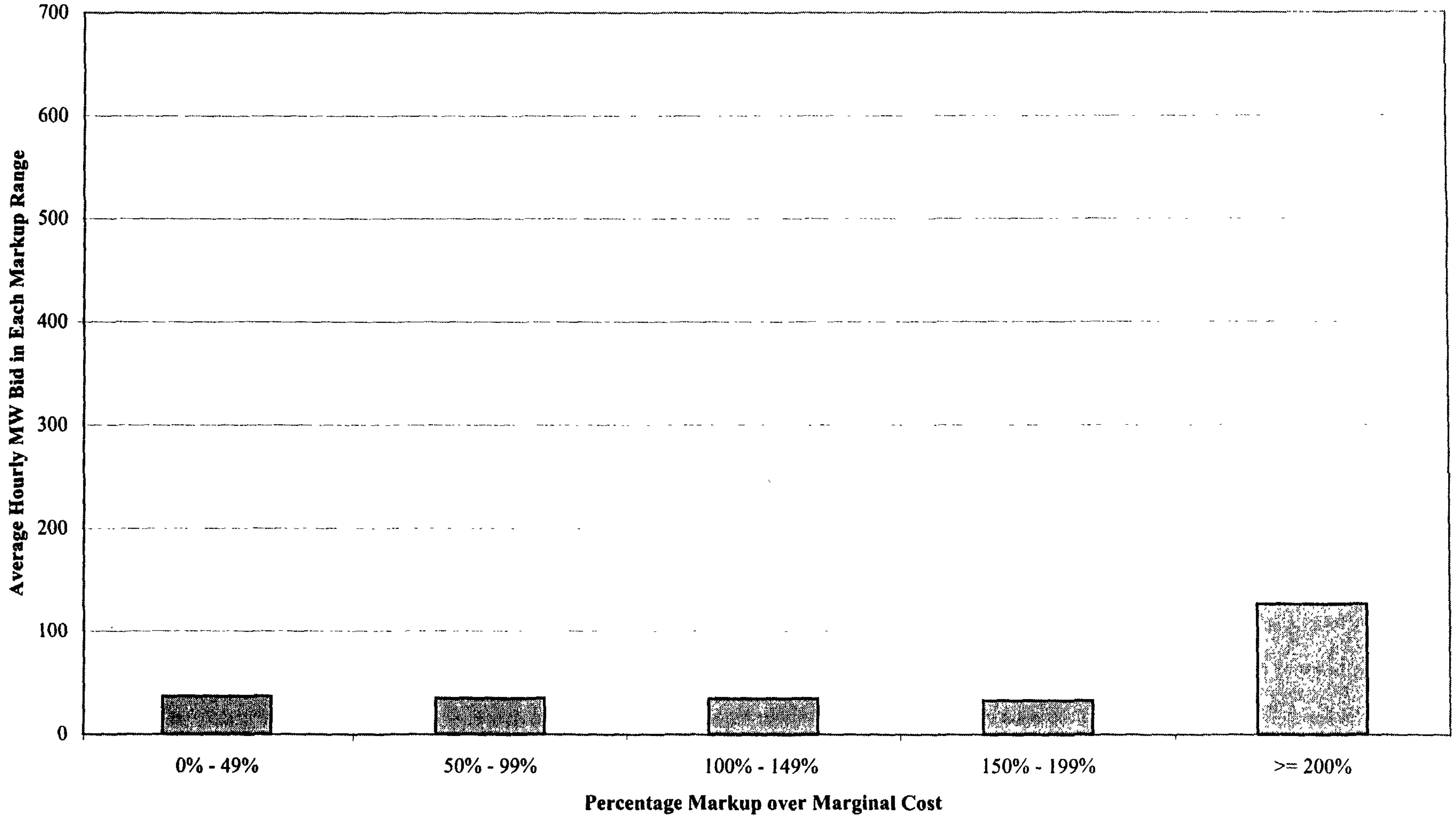
Appendix PQH-I
Reliant Energy Services, Inc.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
7/1/00 - 8/6/00



Sources:
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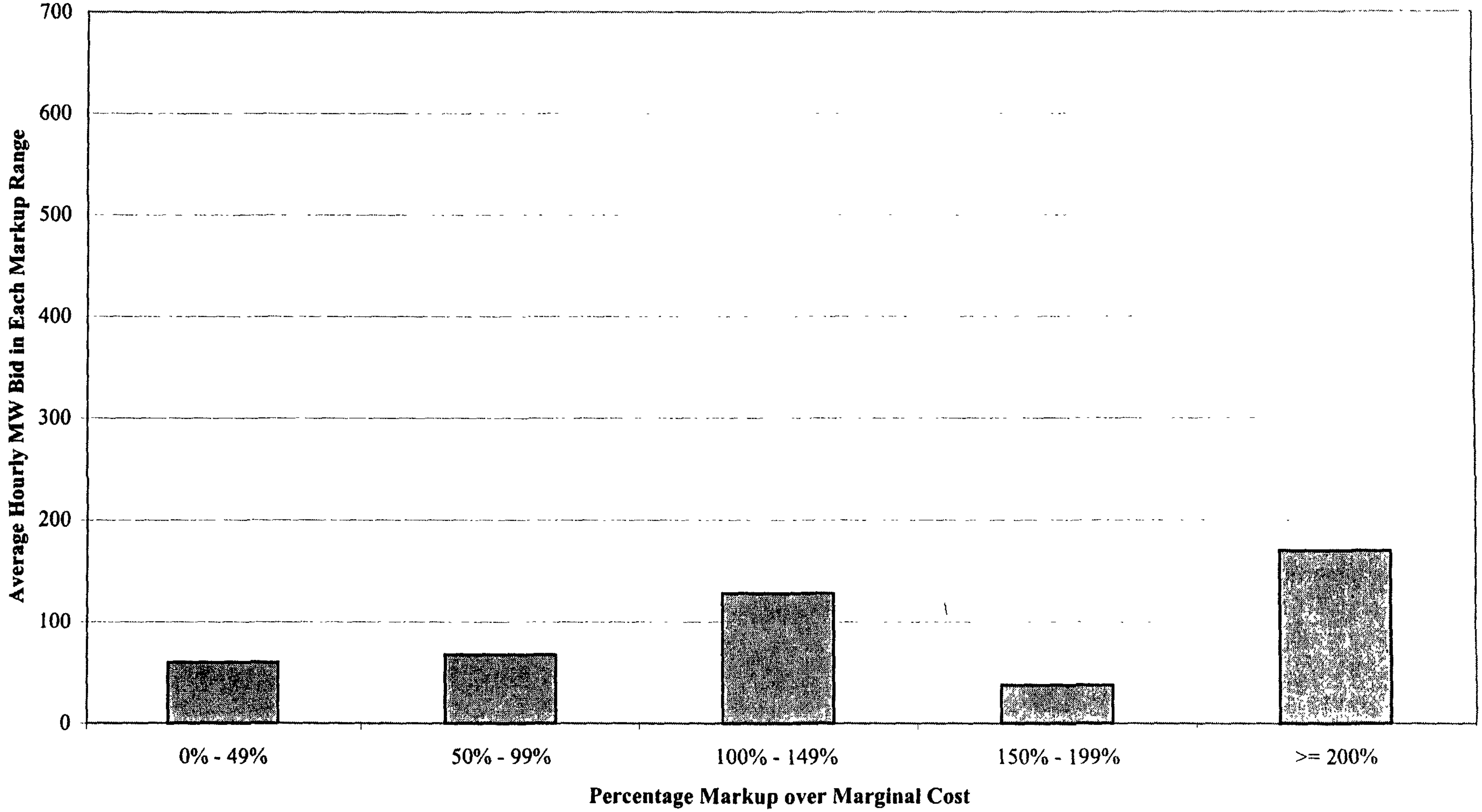
Appendix PQH-I
AES/Williams Energy Services Corporation
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
8/7/00 - 8/31/00



Sources:
[1]: Bid data from CAISO BEEP Stack data.
[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.
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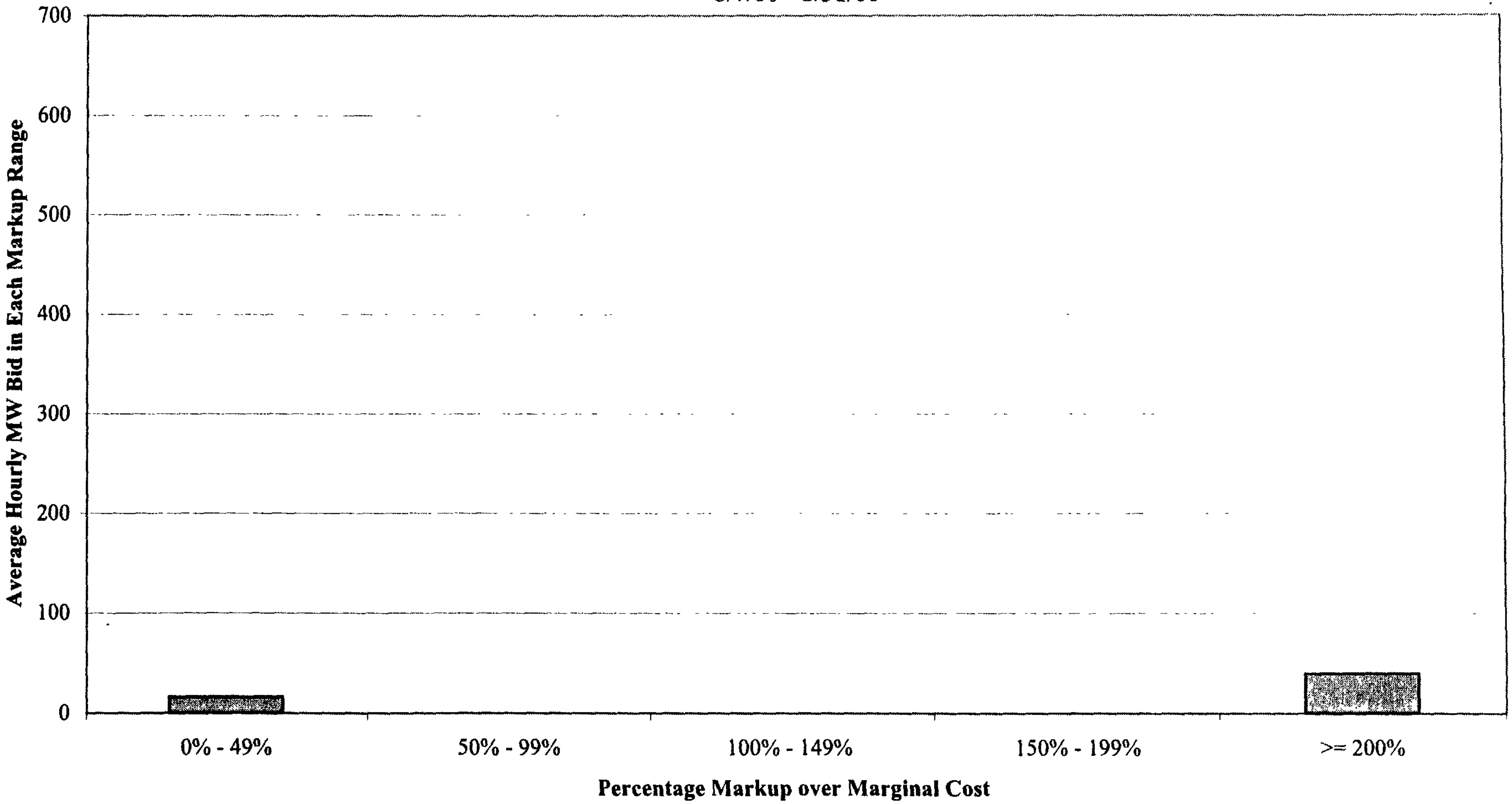
Appendix PQH-I
Duke Energy Trading and Marketing, L.L.C.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
8/7/00 - 8/31/00



Sources:
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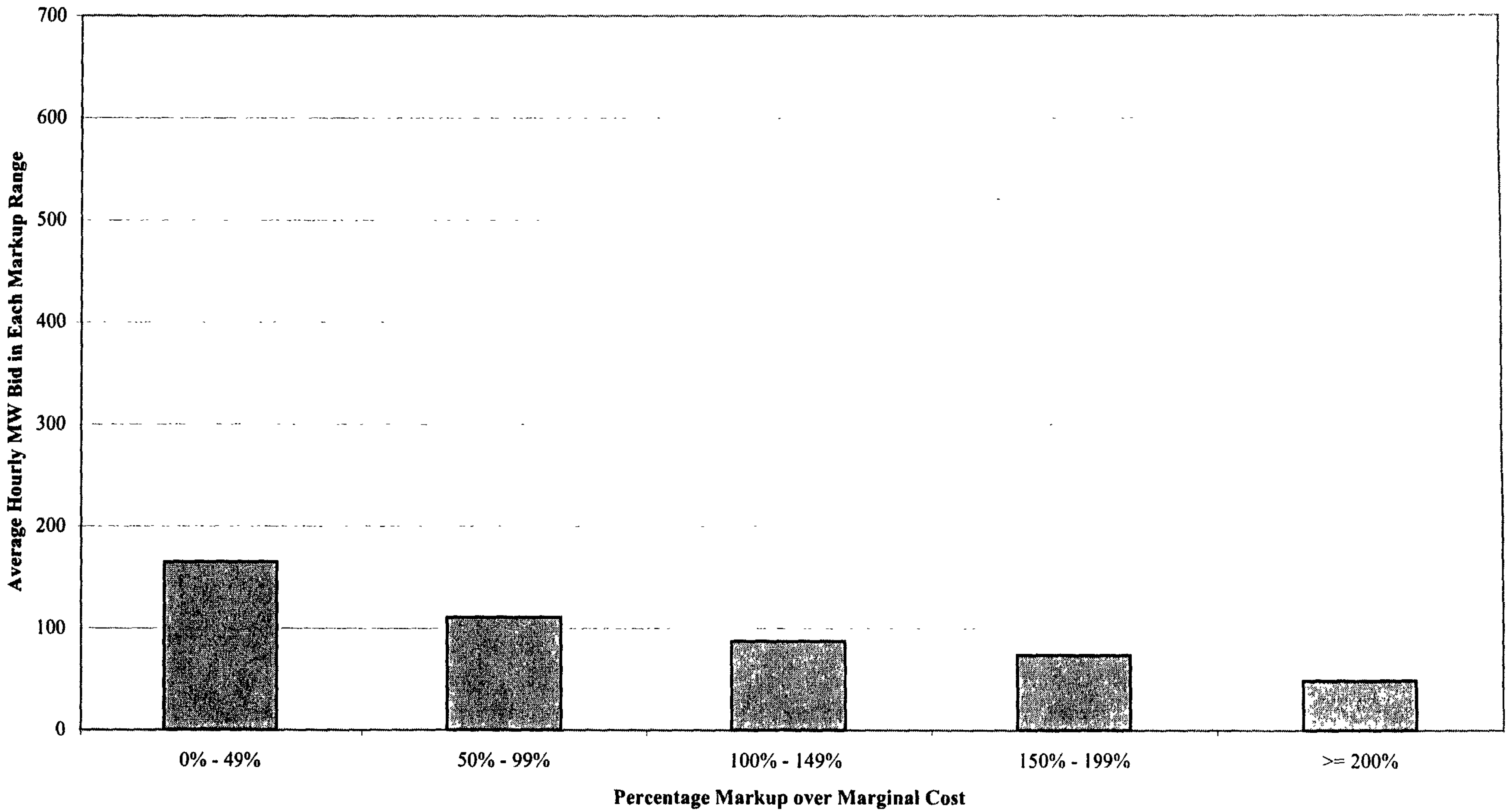
Appendix PQH-I
Dynegy/Electric Clearinghouse
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
8/7/00 - 8/31/00



Sources:

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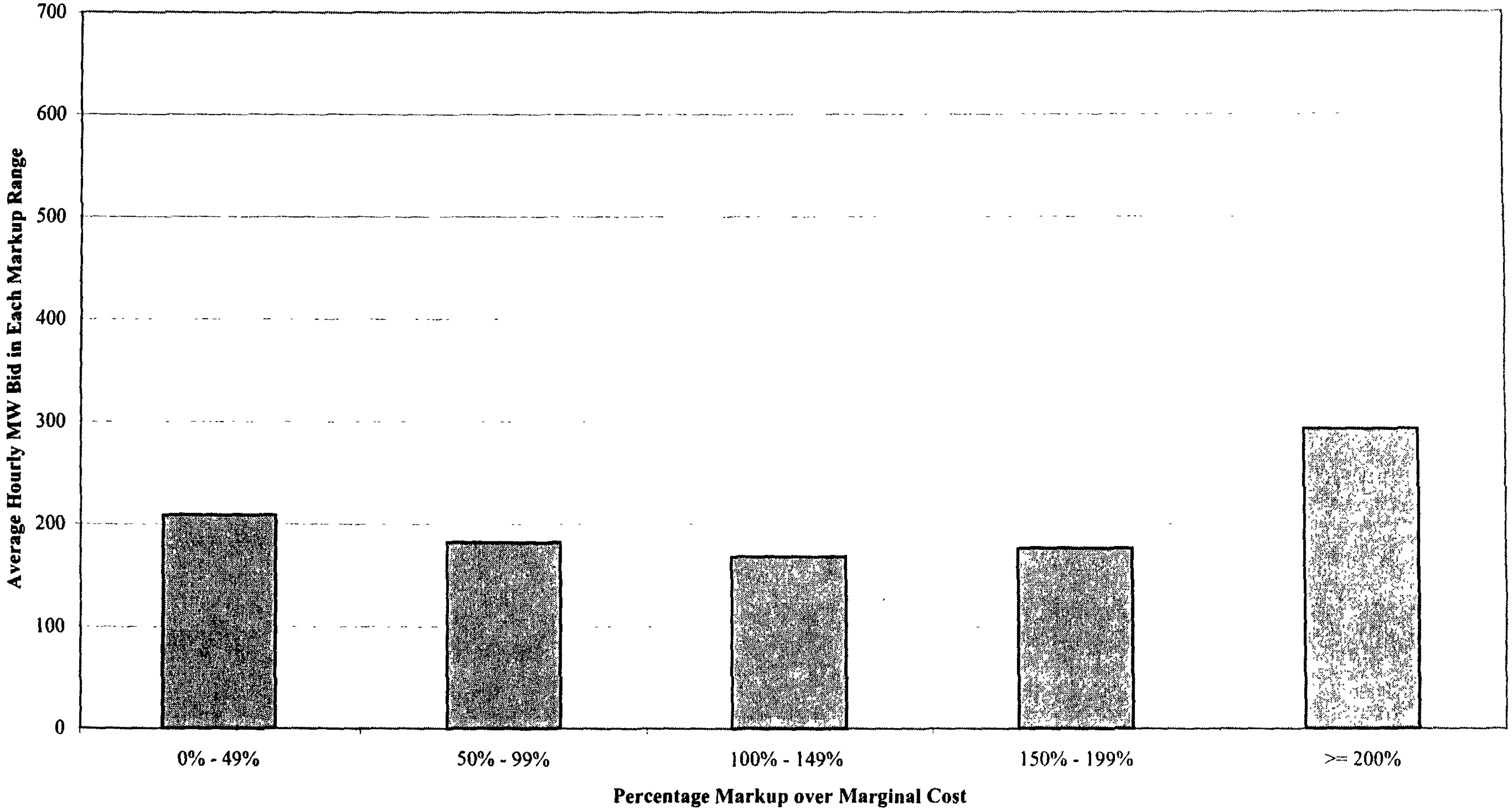
Appendix PQH-I
Mirant/Southern Company Energy Marketing, L.P.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
8/7/00 - 8/31/00



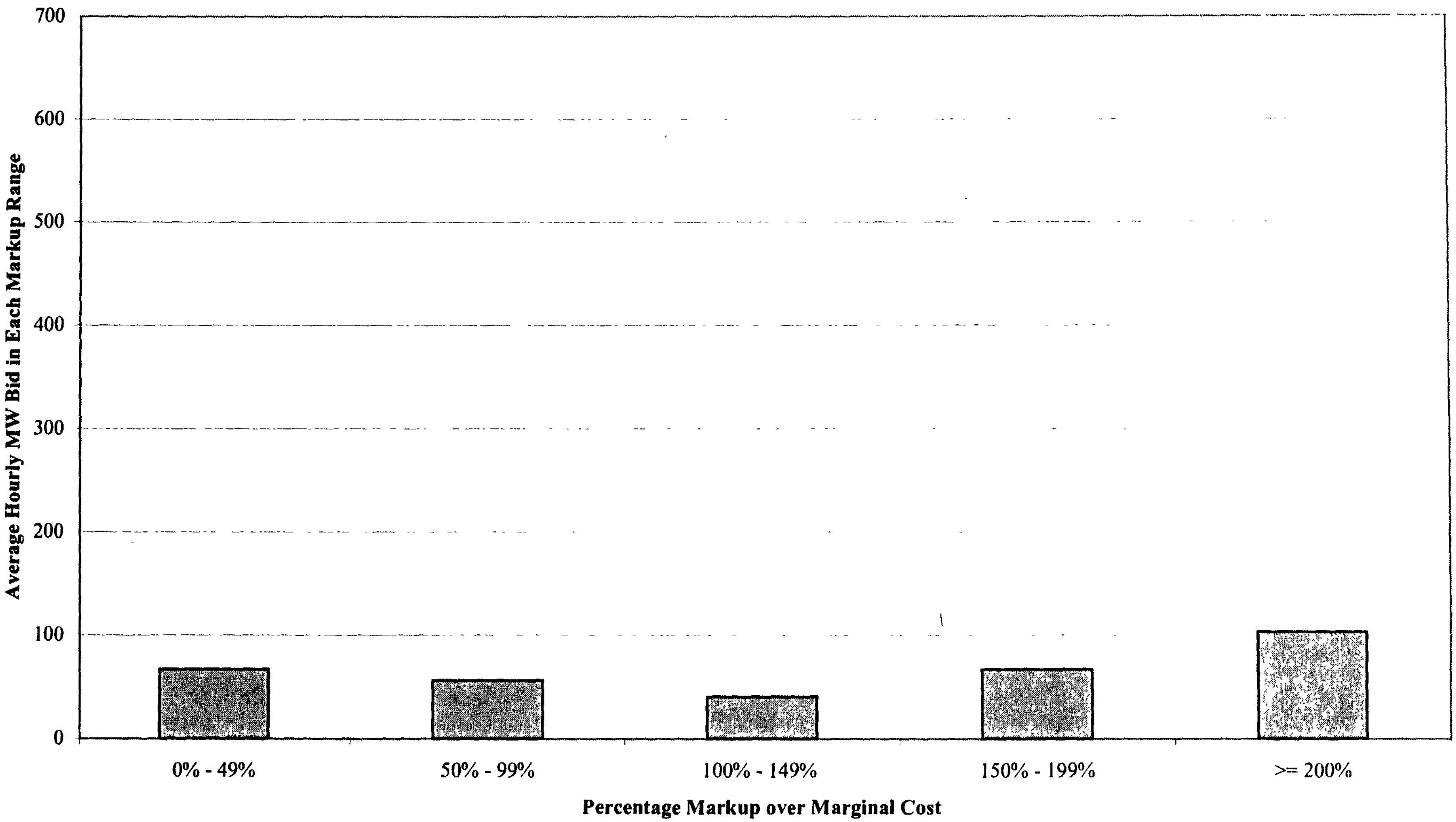
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Reliant Energy Services, Inc.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
8/7/00 - 8/31/00



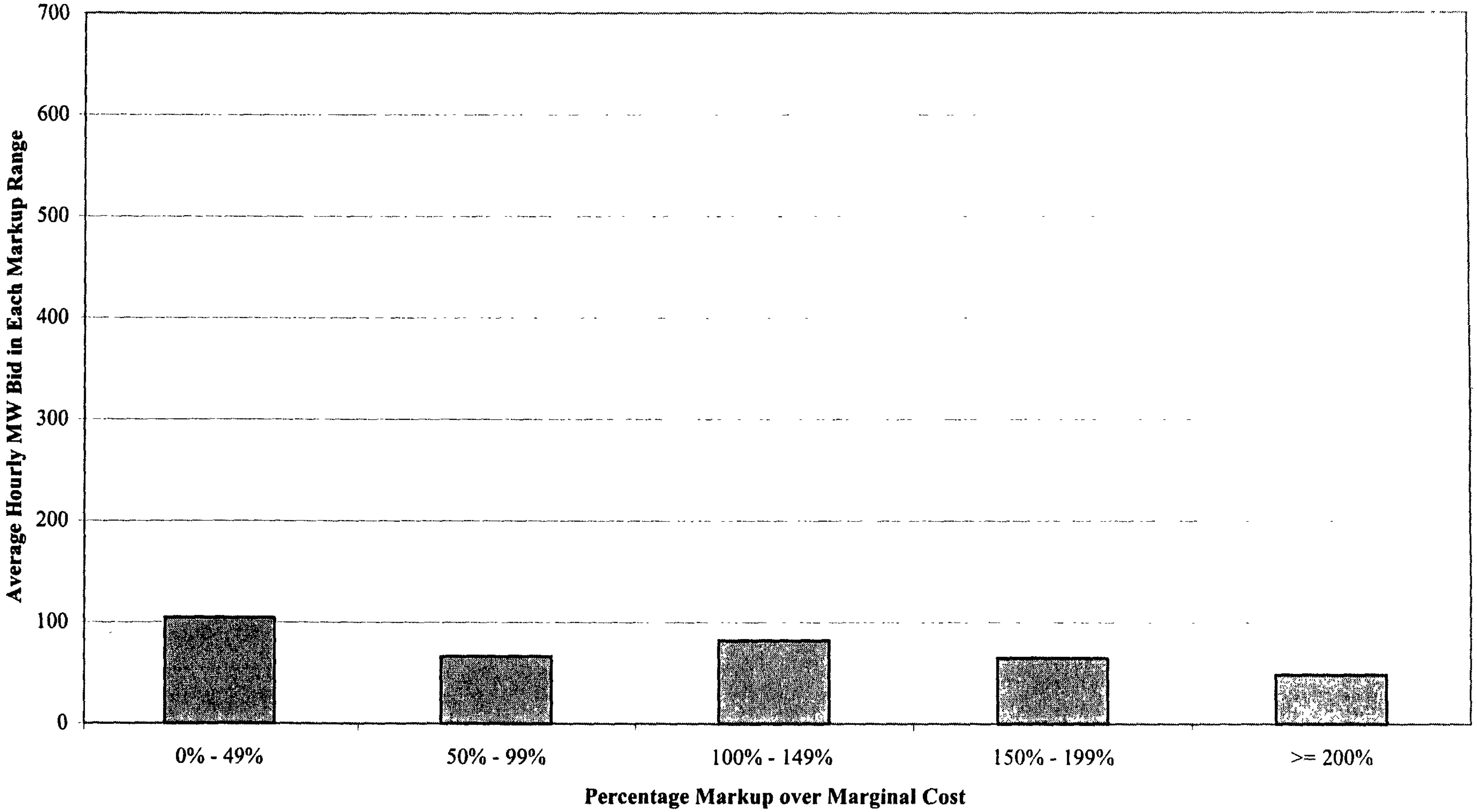
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
AES/Williams Energy Services Corporation
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
9/1/00 - 10/1/00



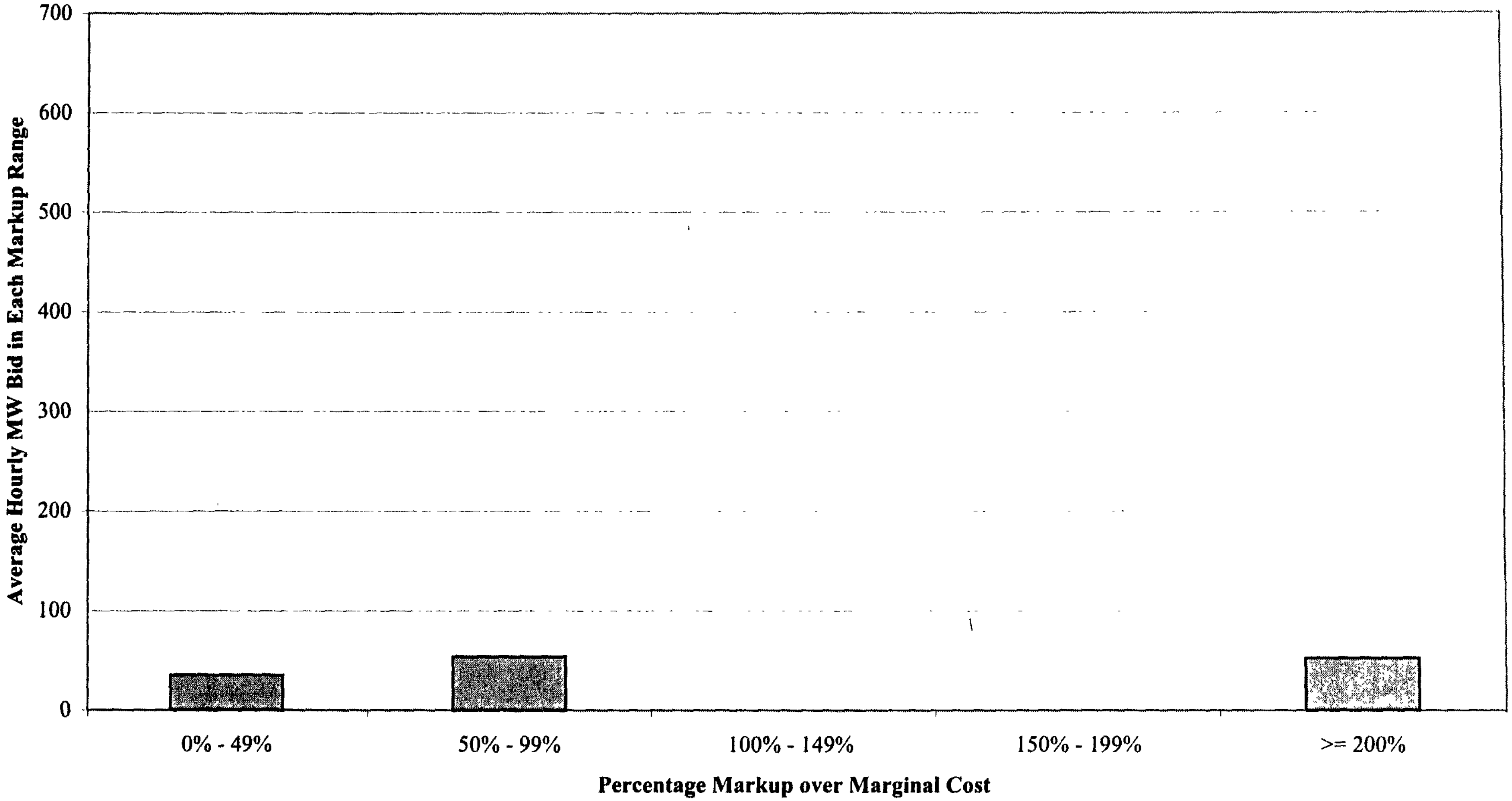
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Duke Energy Trading and Marketing, L.L.C.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
9/1/00 - 10/1/00



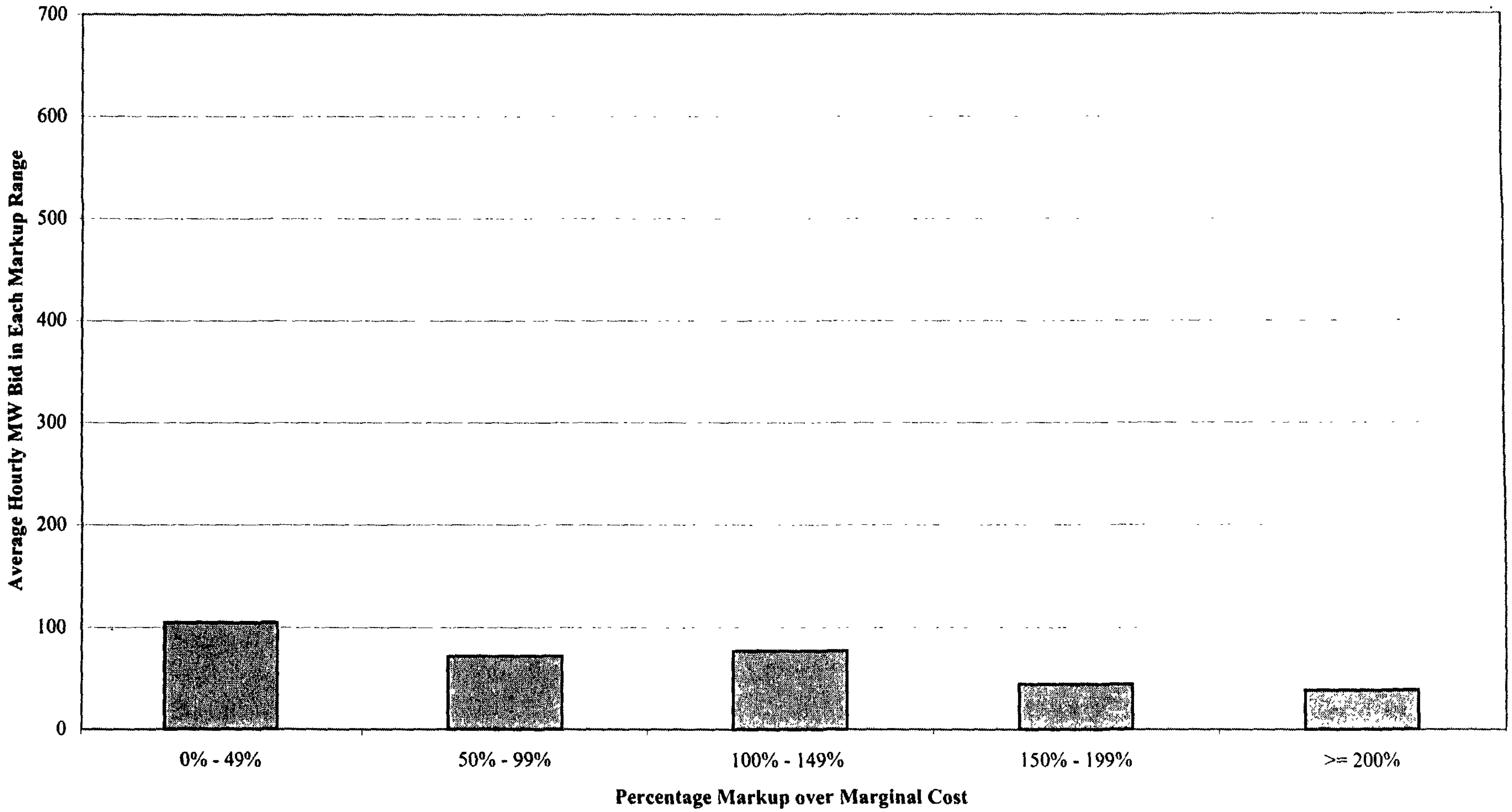
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Dynegy/Electric Clearinghouse
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
9/1/00 - 10/1/00



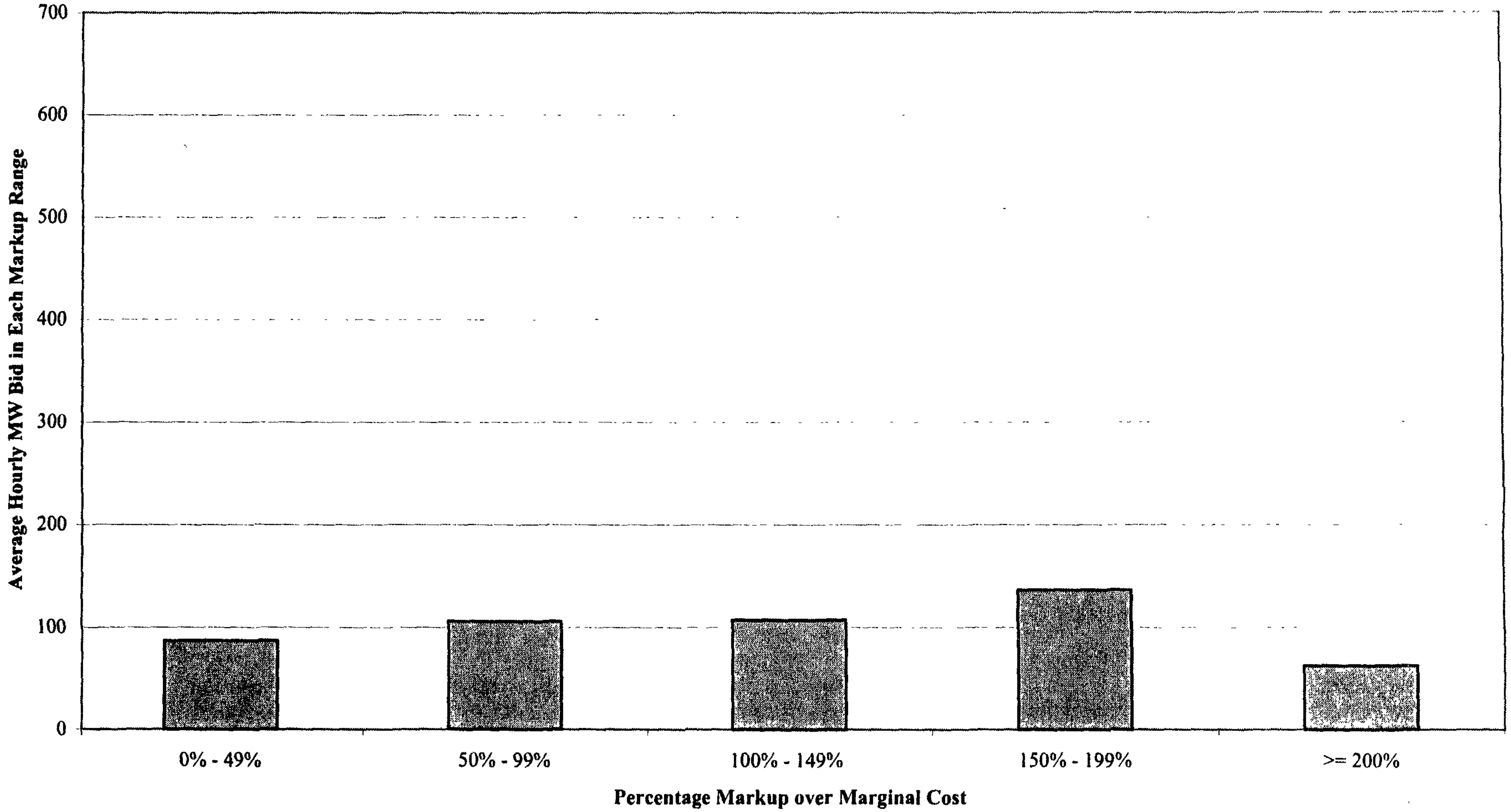
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Mirant/Southern Company Energy Marketing, L.P.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
9/1/00 - 10/1/00



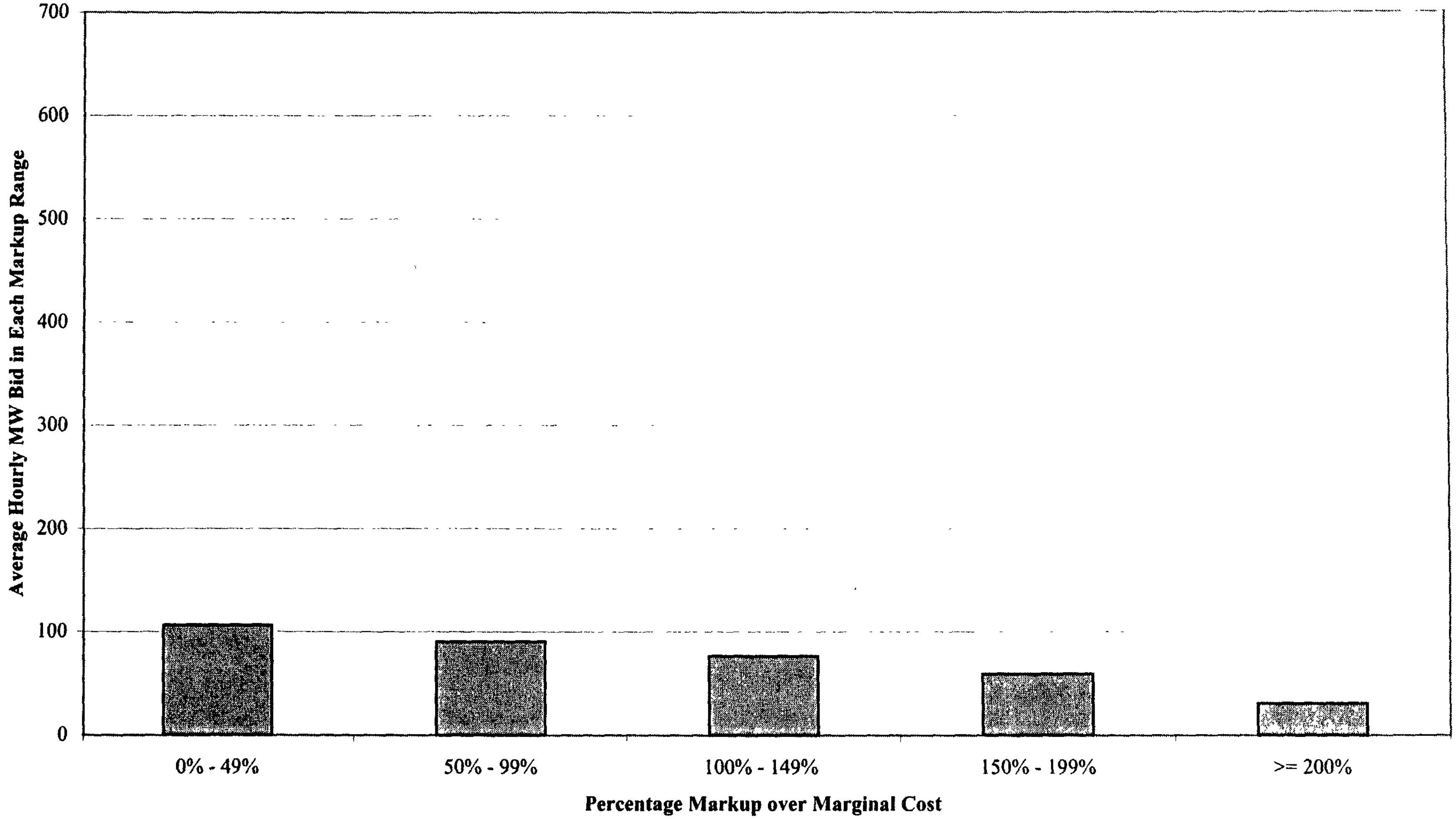
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Reliant Energy Services, Inc.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
9/1/00 - 10/1/00



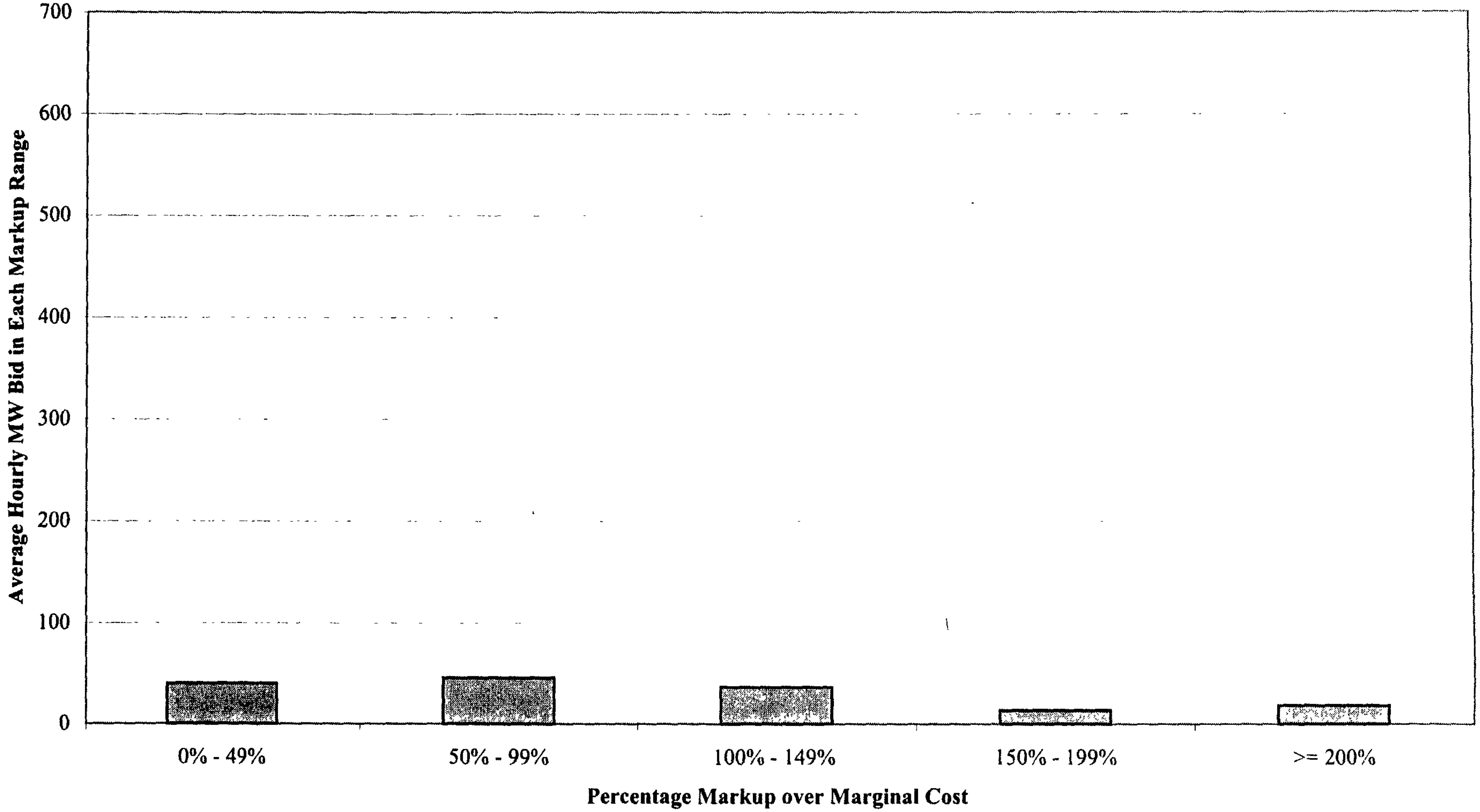
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
AES/Williams Energy Services Corporation
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
10/2/00 - 12/7/00



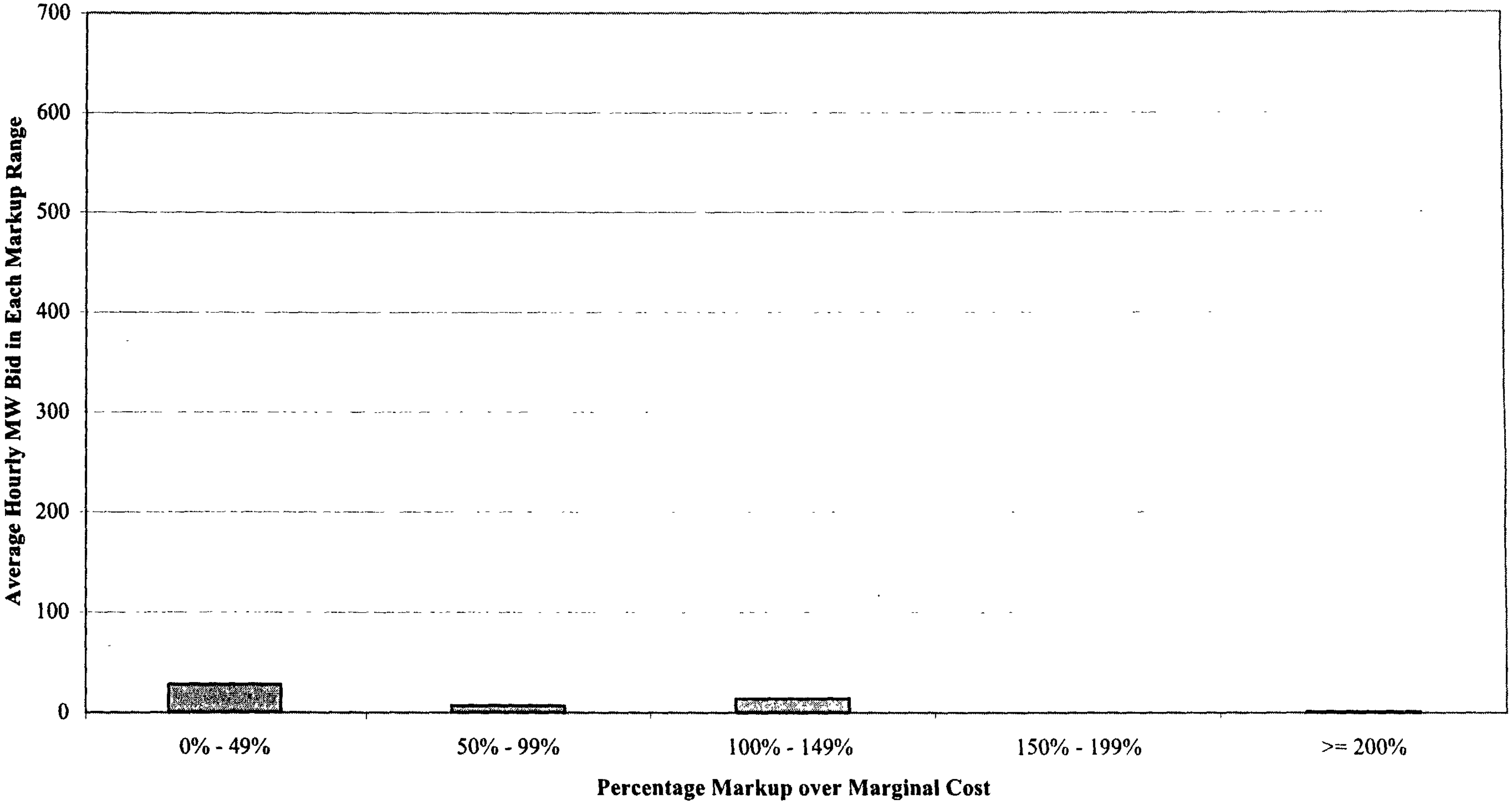
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Duke Energy Trading and Marketing, L.L.C.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
10/2/00 - 12/7/00



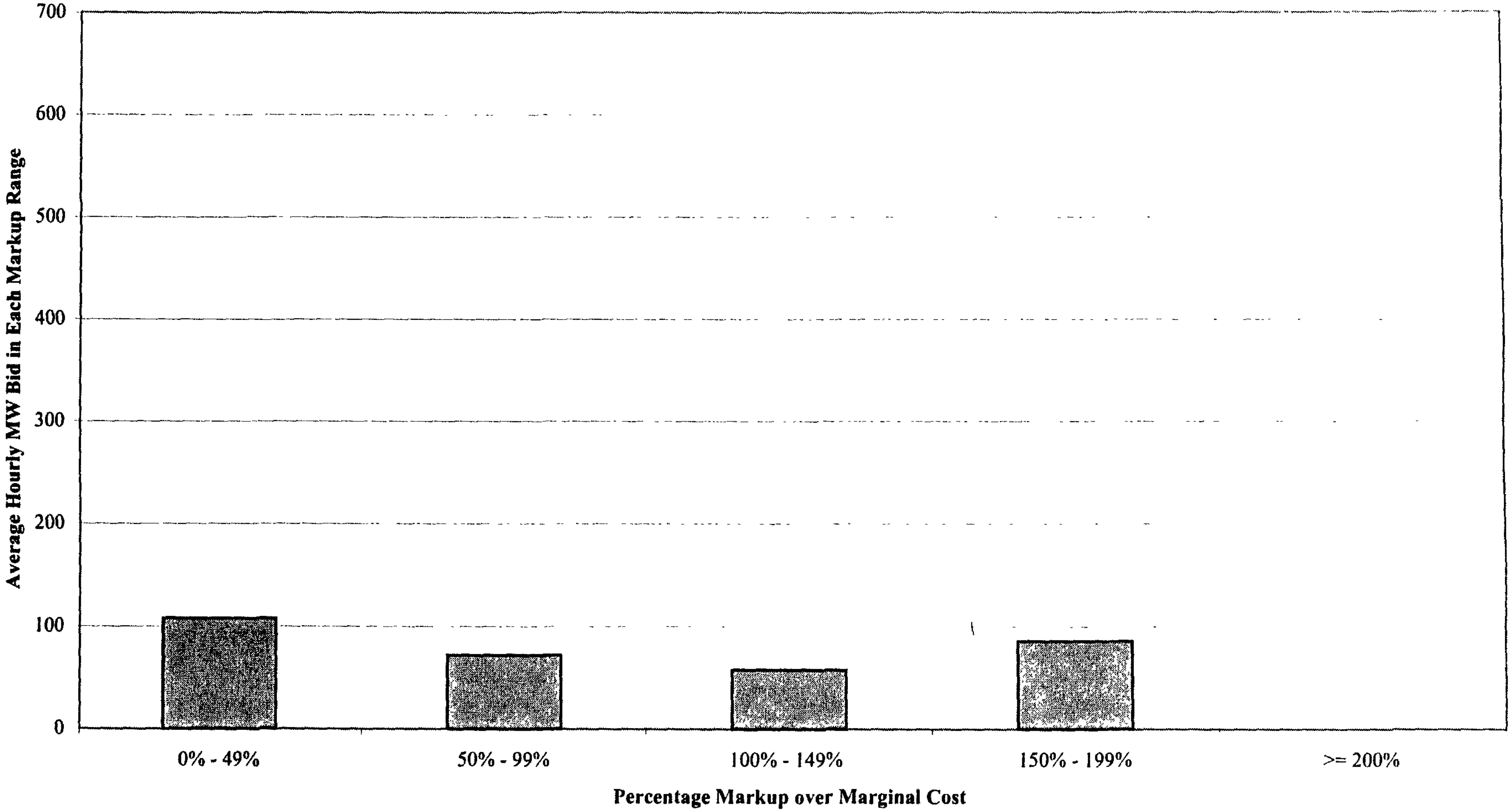
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Dynegy/Electric Clearinghouse
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
10/2/00 - 12/7/00



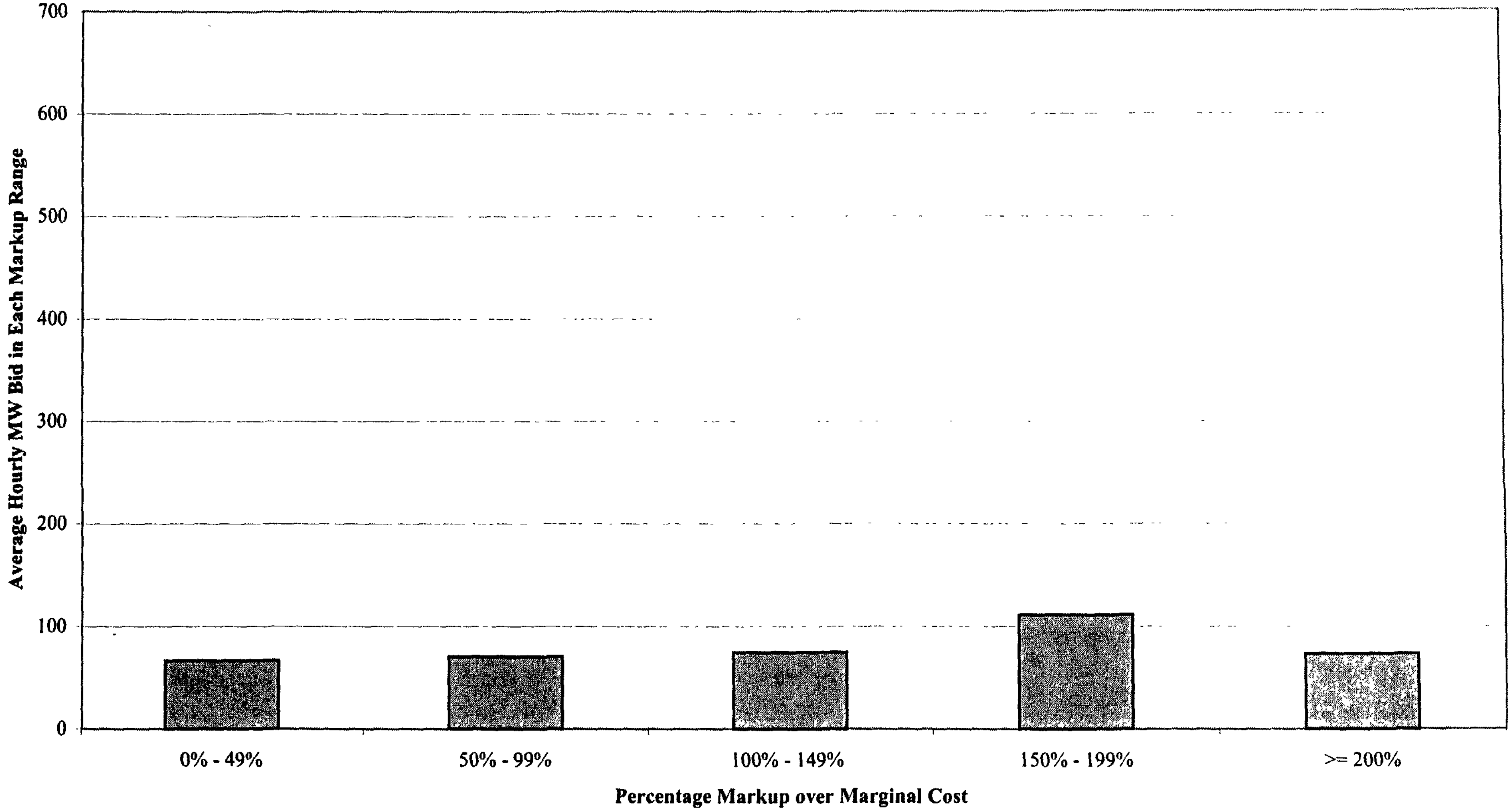
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Mirant/Southern Company Energy Marketing, L.P.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
10/2/00 - 12/7/00



Sources:

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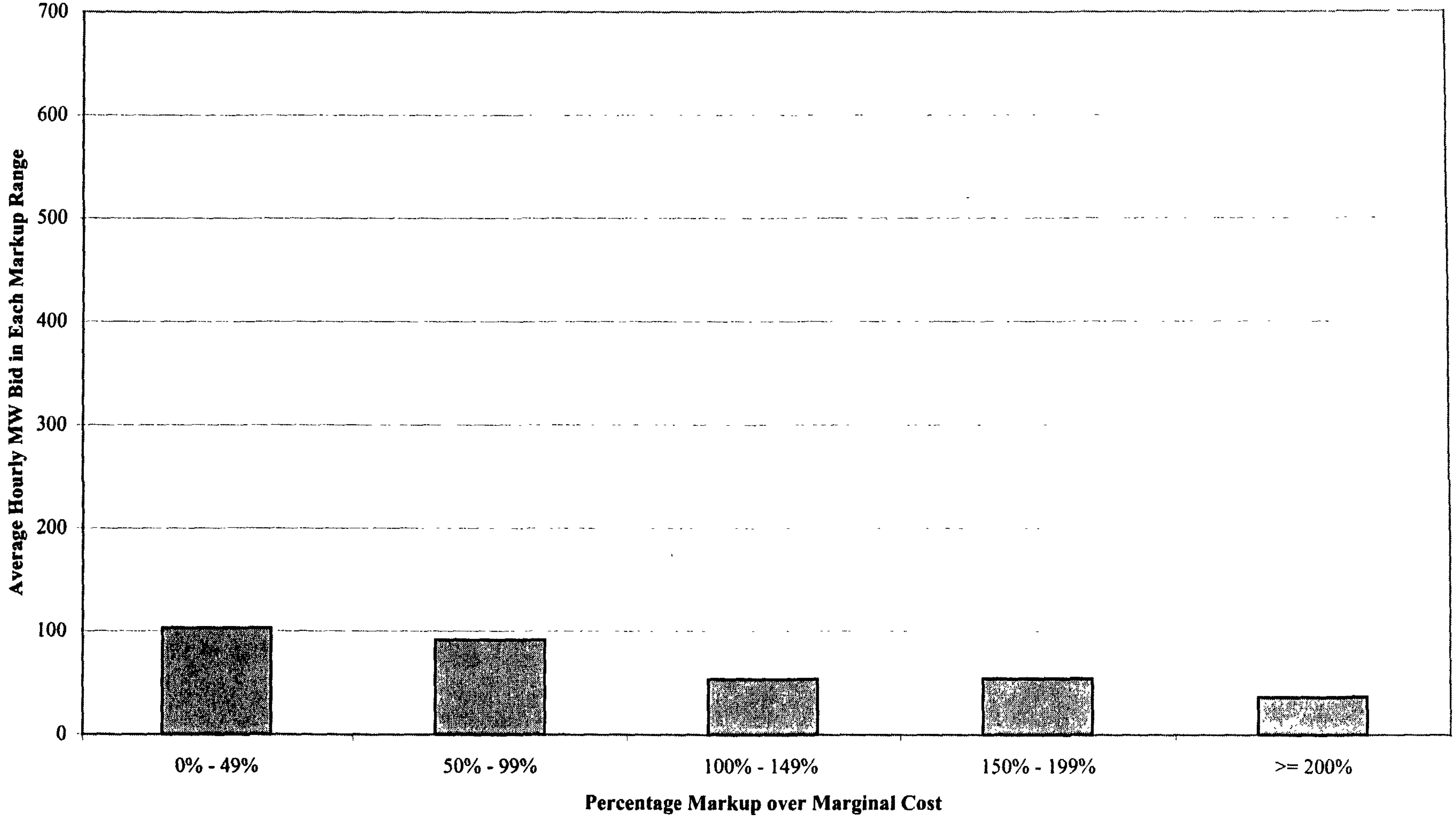
[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Reliant Energy Services, Inc.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
10/2/00 - 12/7/00



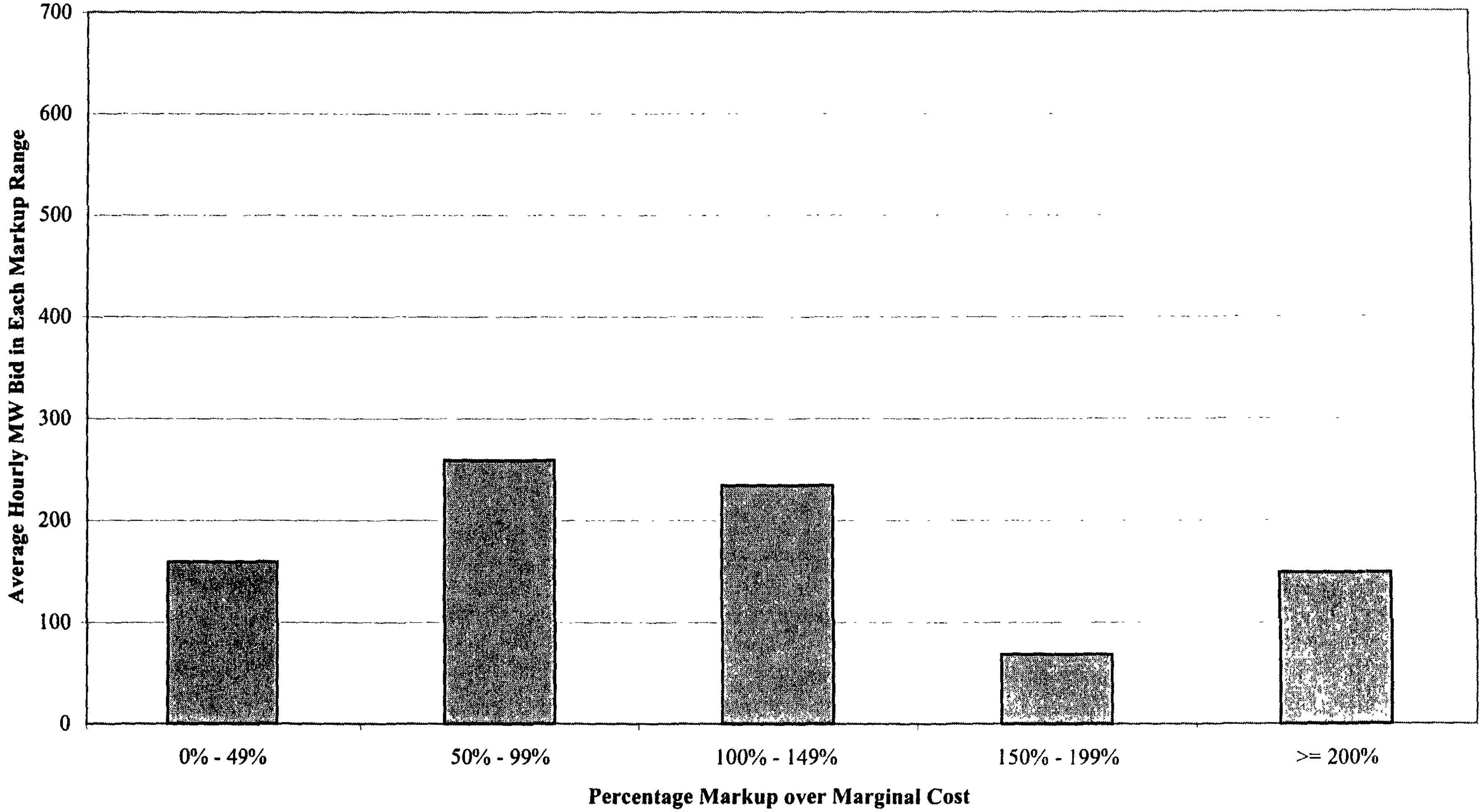
Sources:

[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

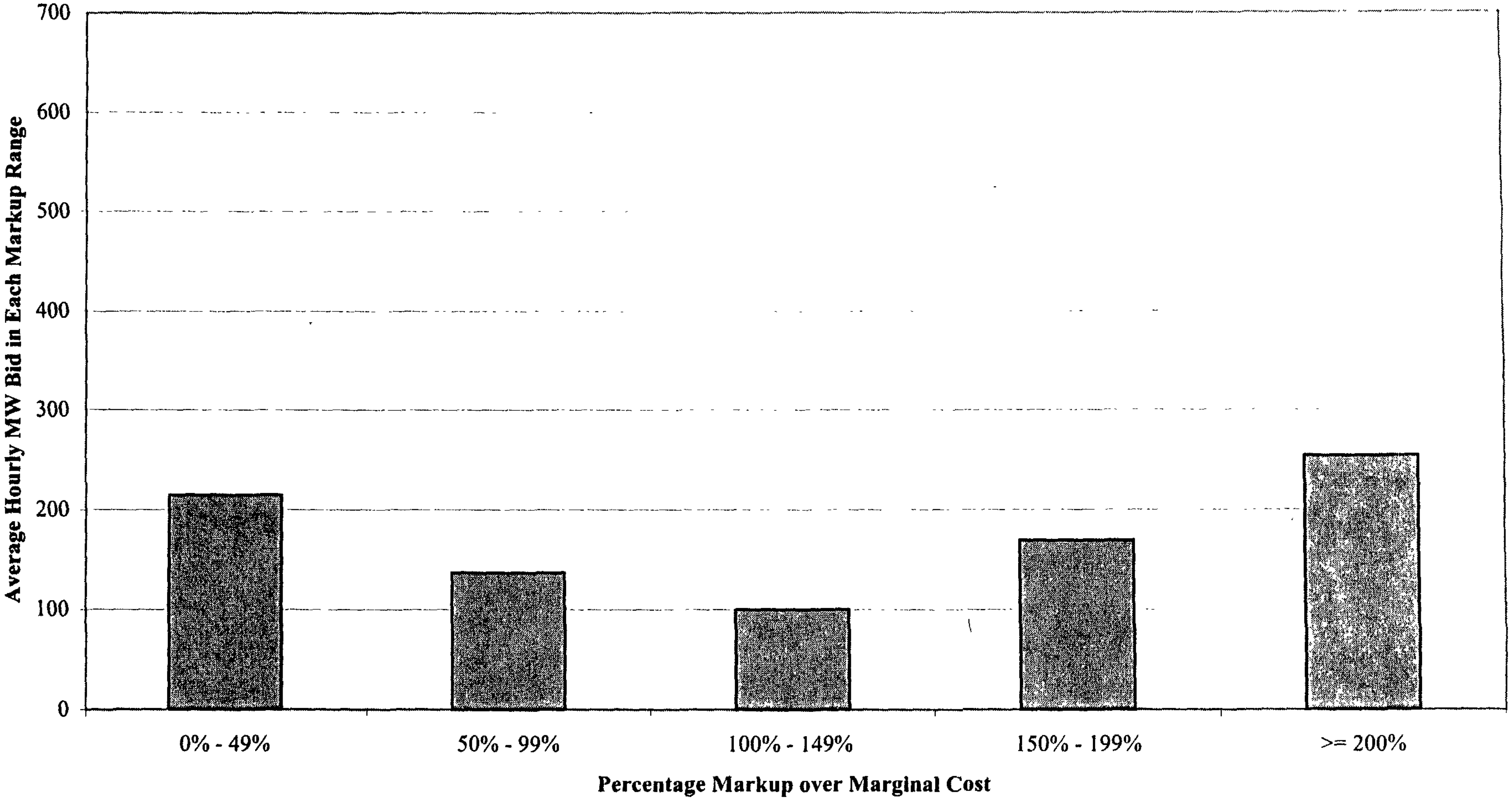
[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
AES/Williams Energy Services Corporation
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
12/8/00 - 1/17/01



Sources:
[1]: Bid data from CAISO BEEP Stack data.
[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.
[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Duke Energy Trading and Marketing, L.L.C.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
12/8/00 - 1/17/01



Sources:

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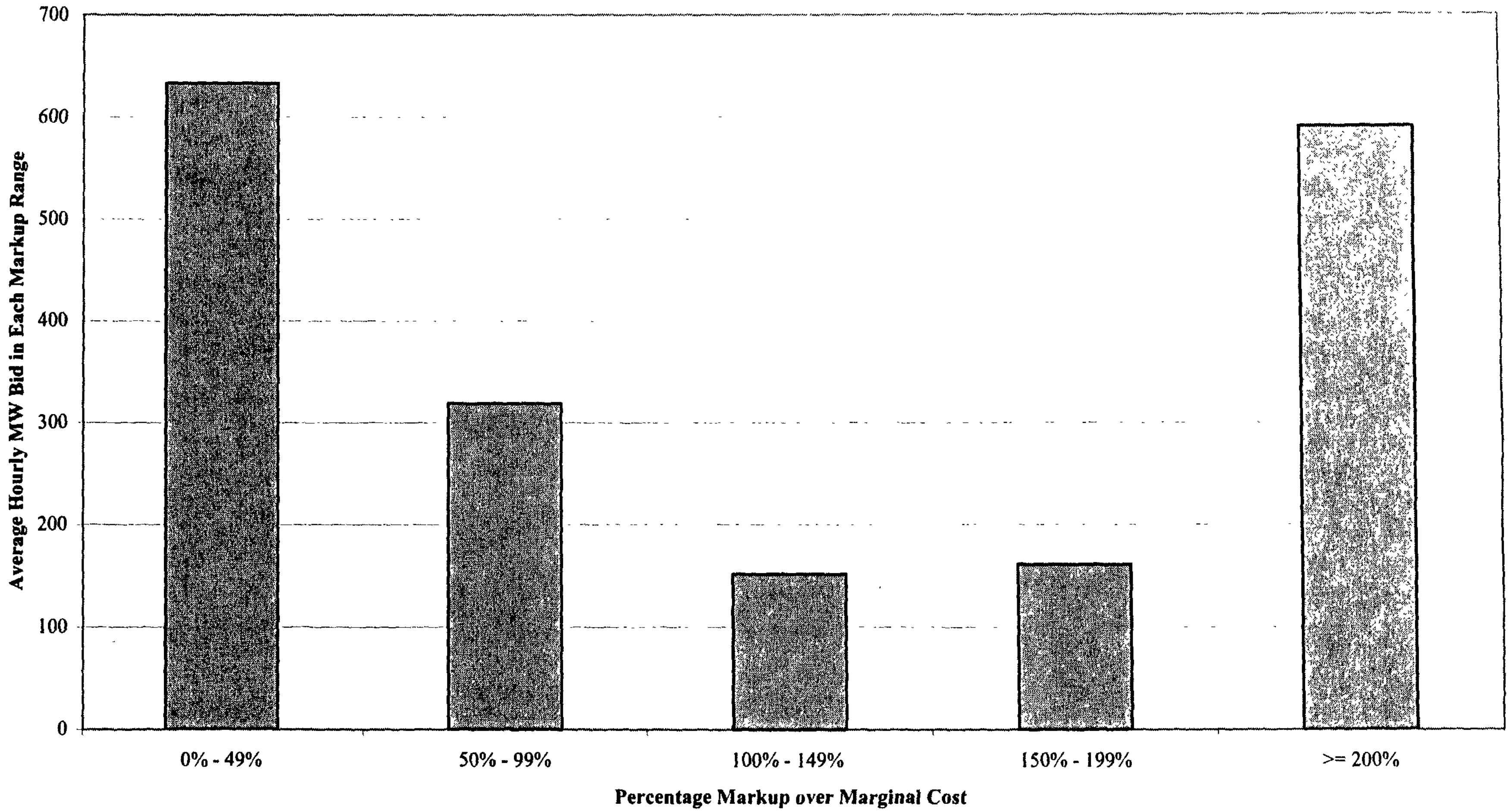
[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Dynegy/Electric Clearinghouse
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
12/8/00 - 1/17/01



Sources:

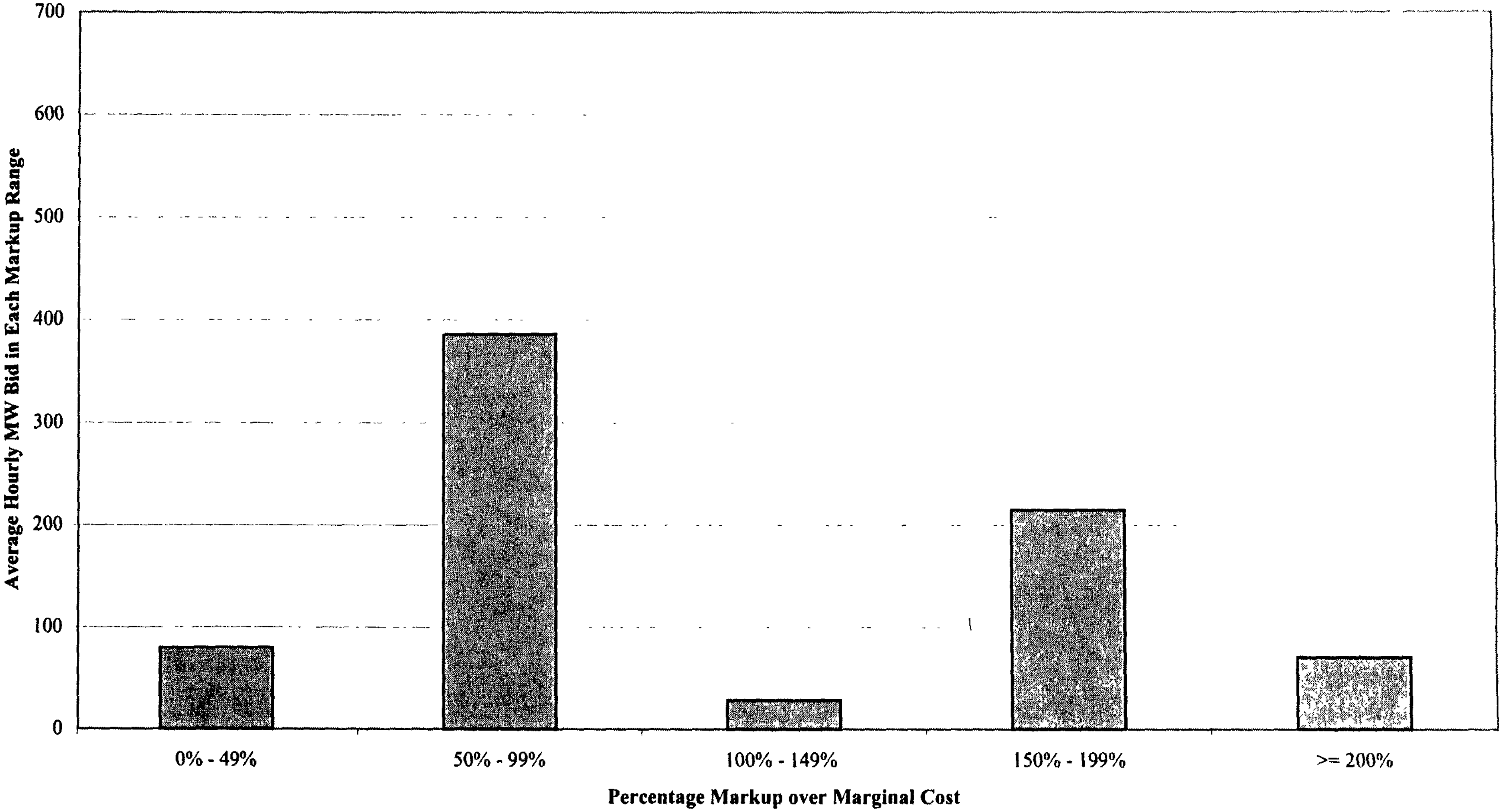
[1]: Bid data from CAISO BEEP Stack data.

[2]: Marginal cost data from Reynolds' testimony. This measure of marginal cost is intentionally conservative and will likely overstate actual marginal costs.

[3]: Analysis does not include bids under marginal cost, such as pricer-taker bids.

Appendix PQH-I
Mirant/Southern Company Energy Marketing, L.P.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours

12/8/00 - 1/17/01



Sources:

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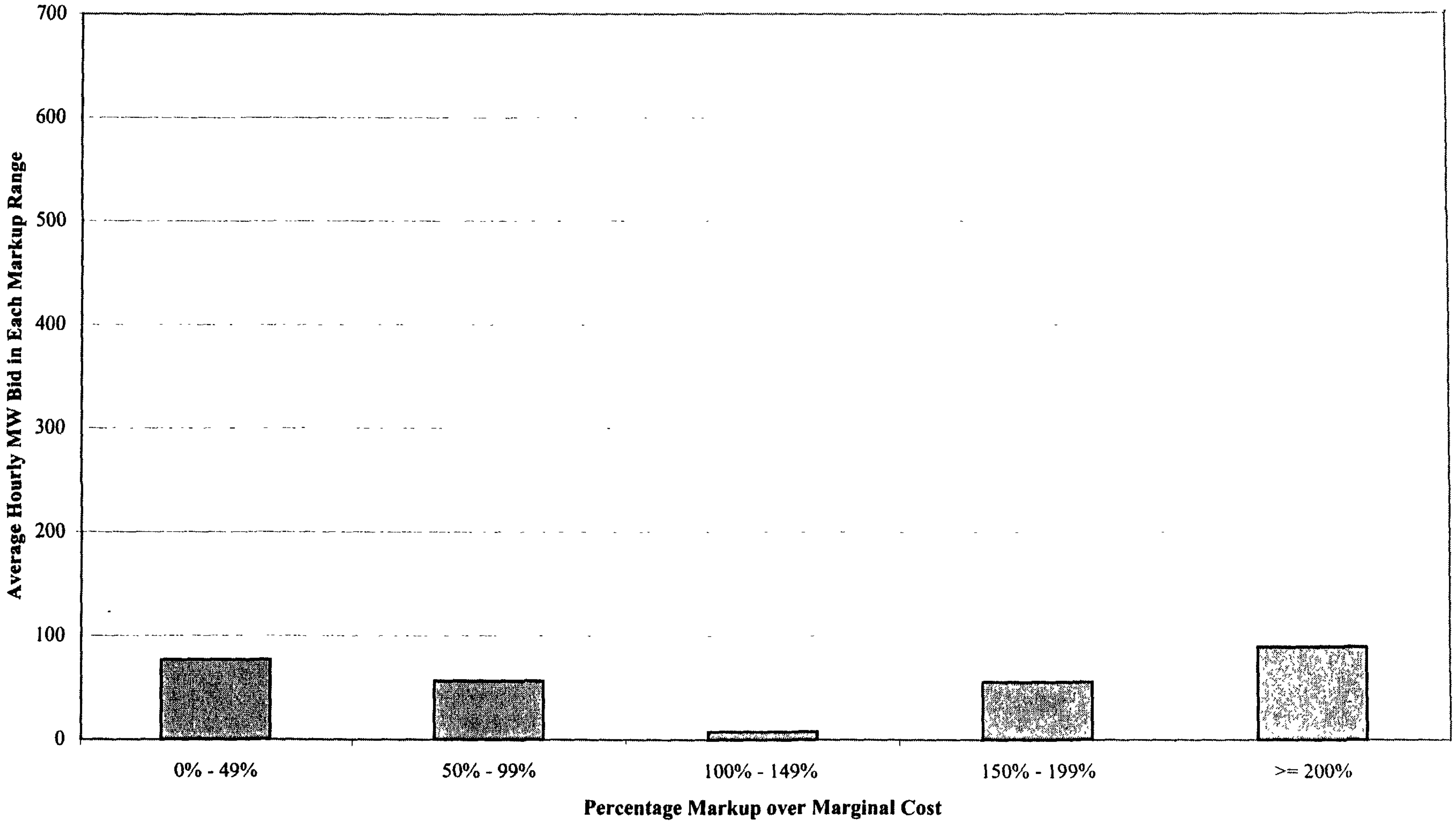
Appendix PQH-I
Reliant Energy Services, Inc.
Distribution of Bid Markup over Marginal Cost
On-Peak Hours
12/8/00 - 1/17/01



Sources:

[1]: Bid data from CAISO BEEP Stack data.

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Appendix PQH-J
Coefficients Based on Price Cap Periods

Variable	Company	1/1/00 - 4/30/00 Price Cap = 750	5/1/00 - 5/31/00 Price Cap = 750	6/1/00 - 6/30/00 Price Cap = 750	7/1/00 - 8/6/00 Price Cap = 500	8/7/00 - 8/31/00 Price Cap = 250	9/1/00 - 10/1/00 Price Cap = 250	10/2/00 - 12/7/00 Price Cap = 250	12/8/00 - 1/17/01 Price Cap = 250/150
MW Below	Duke	1.8734	NS	0.1896	0.2096	0.0465	0.1331	0.0380	0 0762
	Dynegy	0.4627	0.5905	0.4809	0.2792	0.0958	0.0816	0.0914	0.3093
	Reliant	0.2527	0.1310	0.2595	0.0987	0.1274	0.1053	0.1873	0 0847
	Mirant/SCEM	0.4056	0.4611	0.3876	0.2326	0.0761	0 1482	0.2054	0.0260
	AES/Williams	0.1559	0.3804	0.2136	0.0277	0.0464	0.0515	0.0443	0.1931
Demand	Duke	-0.0142	NS	0.0013	-0.0017	NS	-0.0017	NS	0.0186
	Dynegy	NS	-0.0060	-0.0047	0.0033	0.0028	0.0036	0.0029	-0.0023
	Reliant	0.0015	0.0028	0.0026	0.0021	0.0029	0.0022	0.0043	-0.0004
	Mirant/SCEM	0.0003	0.0015	0.0046	-0.0021	0.0017	-0.0023	0.0046	0.0011
	AES/Williams	-0.0112	0.0049	NS	0.0020	0.0048	0.0045	0.0033	-0.0068

Sources and Notes:
[1]: Source - TBG Regressions.
[2]: Dependent variable = price bids greater than marginal cost.
[3]: MW Below = MW below price bid x (1 - (hourly forward delivered/hourly capacity, by supplier).
[4]: Demand = ISO load.
[5]: On 12/8/00 the price cap became a $250 soft price cap. On 1/1/01, this cap was superseded by a $150 soft price cap.
[5]: NS = not significant at 95% confidence level. All other coefficients are significant at 95% confidence level or above.