UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc., ***et al.,***	)	
	)	
Complainant,	)	
	)	
v.	)	**Docket No. EL01-10-005**
	)	
All Jurisdictional Sellers of Energy and/or	)	
Capacity at Wholesale Into Electric Energy	)	
and/or Capacity Markets in the Pacific	)	
Northwest, Including Parties to the Western	)	
Systems Power Pool Agreement,	)	
	)	
Respondents.	)	

PREPARED DIRECT TESTIMONY OF
ROBERT McCULLOUGH
ON BEHALF OF THE CITY OF TACOMA, WASHINGTON
AND THE PORT OF SEATTLE, WASHINGTON

Q. Please identify yourself and give your place of business.

A. My name is Robert McCullough. I am the Managing Partner of McCullough Research, an energy consulting firm specializing in bulk power issues. My address is 6123 S.E. Reed College Place, Portland, Oregon 97202.

Q. Can you briefly summarize your qualifications.

A. Yes. I have been working on the California market failure for the past two and half years years. During that time I have worked with utilities, industries, regulators, and the Oregon, Washington, and California Attorneys General to understand the causes of the California market failure. Our firm's work on Enron's collapse and the possibility of Enron's price leadership in California has resulted in testimony before the Senate Energy and Natural Resources Committee in January, ______, the House Commerce and Energy Committee in February, 2002 and the Senate Committee on Commerce, Science and Transportation, and the California State Senate Committee to Investigate Price Manipulation of the Wholesale Energy Market. My retrospective analysis of the California market failure appeared in the April issue of Public Utilities Fortnightly, the industry's leading periodical, following my January 1, 2001 analysis in the same journal.

My detailed qualifications are contained in Exhibit SEATAC-401 to this testimony.

Q. Have you been active in investigating the California Market Failure and its broader implications?

A. The combination of secrecy, complexity, manipulation, and politics makes work on California a continuing exercise in learning. I have been working on these issues a very long time. During the early 1980's I was involved in California bulk power exports for

Portland General Electric. I was considered an expert, in those early days, in the wholesale transactions over the Pacific Northwest Intertie. I followed the amazing (at the time developments) of E Quad 7 and the BRPU. When the development of California's market began, I represented PGE in the hearings at the CPUC. I have helped utilities and industries buy and sell power in the California market. During this period I have written and spoken extensively on the California market.

When the crisis began, I was retained by a consortia of utilities and industries to investigate the price excursions. My initial reports gained national attention at the time, and this stature has continued to the present day. We have worked on the crisis for a variety of clients, ranging from the California Attorney General's office to Alcan Aluminum. As I mentioned above, I have testified before Congress three times on Enron and the California market failure as well as in front of the California State Senate Committee to Investigate Price Manipulation of the Wholesale Energy Market. I have testified before FERC on California issues in FERC Docket Nos. EL01-10-000 and EL02-28-000, *et al*.

Withholding

Q. What is the role of withholding generation in the California crisis?

A. Extensive evidence exists that California generators either chose to not bid or to not generate throughout the California crisis. A recent California Public Utilities Commission report summarizes their conclusions as:

> The ISO and the Commission staff agree on a number of crucial substantive points, namely:

• Generators did not bid all their capacity into the ISO's markets. This in turn forced the ISO to find and procure resources in “real time” (that is, under pressure at the last minute) in order to serve load.

• Generators did not follow dispatch instructions. Those failures to follow dispatch instructions during system emergencies imperiled the system and the provision of reliable electrical service to the State.

• Generators declined Automatic Dispatch System instructions, citing "economic considerations," conduct which was not reasonable under the circumstances. By Commission staff’s count, generators refused in this way to increase power production 311 times (even ignoring dispatches for less than 5 megawatts) because the ISO tried to dispatch many bids multiple times during a particular hour. (Meanwhile, in the same period, generators did not respond to the ISO instructions for 5 megawatts or more of power 1623 times. More than a third of these 1623 instructions were ISO requests for 50 or more megawatts of power.

• The ISO encountered circumstances where generators refused to run, citing lack of operating personnel, or argued with ISO operators over the prices at which they would run. Such conduct was also unreasonable under the circumstances.

• Generators wrongly assert that the ISO had full operational control over the grid through RMR contracts and/or Automatic Generation Control (AGC).[1]

Q. What new evidence do we have of withholding in California?

A. Reliant, AES, and Williams staff have been recorded in planning plant outages in order to manipulate the market.

Reliant Trader 2: What we are kinda thinking about doing right now is coming out and trying to buy Q3. Buy dailies and then shut down all the plants and then if it goes against us putting that, unwind hedges in the plant book.

Reliant Manager 1: Yeah.

Reliant Trader 2: And then that way we going to put out that we are short NOx, we're short capacity factor—or we're worried about the capacity factor of units, and trying to get people to say look we can't – these levels don't make sense to do. I mean at 88 bucks and just kinda um….then we can make the argument internally if we have to.

Reliant Manager 1: That it was a 21 buck margin.

Reliant Trader 2: Yeah. I mean, we're down to $40.00 profit margin now where as last week we were $70.00, and we'd rather unwind stuff and carry into the summer.

[1]Supplement to the California Public Utilities Commission Staff's Wholesale Generator Investigation Report, September 17, 2002, at 2 (SEATAC-701).

Reliant Manager 1: Yeah. And plus we'll use the deal we don't know what Ormond's going to be doing and there's problems popping up.

Reliant Trader 2: Right. I mean, I feel more—I feel better about that than going out and just coming out short when I think the market is going to rebound at some point. Right now. But we're still talking about it right now.

Reliant Manager 1: Well I was talking about the Q—the 2001.

Reliant Trader 2: Well, yeah, I mean if it props up there and we're selling 2001. I mean we're doing this to prop up 2001 to sell into it.[2]

Later Reliant transcripts are even more explicit:

Reliant Ops Manager 1: Yeah. That's probably the way to go if ya'll can swing it. If not, if we have to do it then I don't necessarily foresee those units being run the remainder of this week. In fact you will probably see, in fact I know, tomorrow we will have all the units at Coolwater off.

Reliant Plant Operator 2: Really?

Reliant Ops Manager 1: Potentially. Even number four. More due to some market manipulation attempts on our part. And so, on number four it probably wouldn't last long. It would probably be back on the next day, if not the day after that. Trying to uh...

Reliant Plant Operator 2: Trying to shorten the supply, uh? That way the

[2]Reliant Transcript, 6:30 A.M. June 20, 2000, at 1(SEATAC-48).

> price on demand goes up.[3]

And:

> Reliant Trader 1: Yeah, we literally shut everything off but Ormand. Everybody's like, you can't do that, and we're like, watch us. And it worked.
>
> Reliant Trader 3: Did the market find out?
>
> Reliant Trader 1: No, god no. They – somebody, you know, figured out because they said that, came out in one of the rags that a non-utility generator looked like they were withholding generation. But, see we didn't because we really bid it in. We just bid it in very high.[4]

Q. Do we have any other similar transcripts?

A. Yes. FERC's investigation of Williams found similar transcripts:

> In particular, on April 27, 2000, Ms. Morgan stated to an AES employee that, "if your Unit 4 outage runs long and if you need more time, we don't have a problem with that" and "if you need more time, just let us know." Ms. Morgan then explained the reason Williams wanted the shutdown extended: because the ISO was paying "a premium" for use of the non-RMR unit. She concluded that "that's one reason it wouldn't hurt Williams' feelings if the outage ran long ." Ms. Morgan then stated that if AES extended the outage, Williams "could probably give [AES] a break on

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[3] Reliant Transcript, 8:25 A.M. June 20, 2000, at 1 (SEATAC-48).

[4] Reliant Transcript, 9:27 A.M. June 23, 2000, at 3 (SEATAC-48).

availability," apparently meaning that Williams would not count Alamitos 4 as "unavailable" during the additional days of the outage . (AES is required under its operating contract with Williams, known as the Tolling Agreement, to keep units available a minimum number of hours throughout the contract year. Mr. White's request for repairs noted that Alamitos 4 was very low on availability. Not counting as "unavailable" hours during which Alamitos 4 would be off-line during this outage would permit AES to declare Alamitos 4 "unavailable" for a comparable period at another time.) Ms. Morgan then advised the AES employee that Williams would not give AES a cut of the profit Williams would obtain from the extension of the outage, just the "break" on availability.

Later that day, Eric Pendergraft, a high-ranking AES employee, followed up this conversation, expressing his understanding that "you guys were saying that it might not be such a bad thing if it took us a little while longer to do our work." Morgan responded by saying "we're not trying to talk yous [sic] into doin' it but it wouldn't hurt, you know, we wouldn't like throw a fit if it took any longer." Mr. Pendergraft responded: "Then you wouldn't hit us for availability?" Ms. Morgan agreed, adding "I don't wanna do something underhanded, but if there's work you can continue to do . . ." Mr. Pendergraft stated, "I understand. You don't have to talk anymore." He then stated that, "We probably oughta have things we'd like to do in preparation for the summer, so . . . that might work out." AES extended the

Alamitos 4 outage through May 5 to do maintenance work on the burners and the 6th point heater drip line.[5]

Q. Was behavior like this observed frequently?

A. Yes. The plants owned by the "Big Five" (Reliant, Duke, Williams, Mirant, and Dynegy) failed to generate near their capacity during system emergencies, only averaging operating rates of 50% to 60% during emergency conditions.[6]

Big Five Generation	MW		
Nameplate Capacity	15636		
Maximum Generation Observed, 2000-2001	13712		
		% of Capacity	% of Maximum
Average Generation, May 22, 2000 - July 3, 2001	7993	51.1%	58.3%
Average Generation, Stage 1 Emergencies	8698	55.6%	63.4%
Average Generation, Stage 2 Emergencies	8493	54.3%	61.9%
Average Generation, Stage 3 Emergencies	8277	52.9%	60.4%
Average Generation, January 17, 2001	8578	54.9%	62.6%
Average Generation, January 18, 2001	8442	54.0%	61.6%
Average Generation, July 4, 2001 - August 31, 2001	8560	54.7%	62.4%

Overall, the big five plants only managed to generate at rates equal to 51.1% of rated capacity during the crisis.[7]

Q. What do we know about these plants?

A. Actually, we know quite a lot. All of the plants were subject to an Environmental Impact Statement before they were sold. Plant data is accumulated by FERC and the Energy

[5] Non-Public Appendix to Order Directing Williams Energy Marketing & Trading Company and AES Southland, Inc., to Show Cause Docket No. INOI-3-000, at 3 (SEATAC-58).

[6] (SEATAC-402 and SEATAC-403).

[7] *Id.*

Information Administration (EIA). Most of the “big five” already own similar plants elsewhere in their utility subsidiaries.

Q. Are the plants too old to operate efficiently?

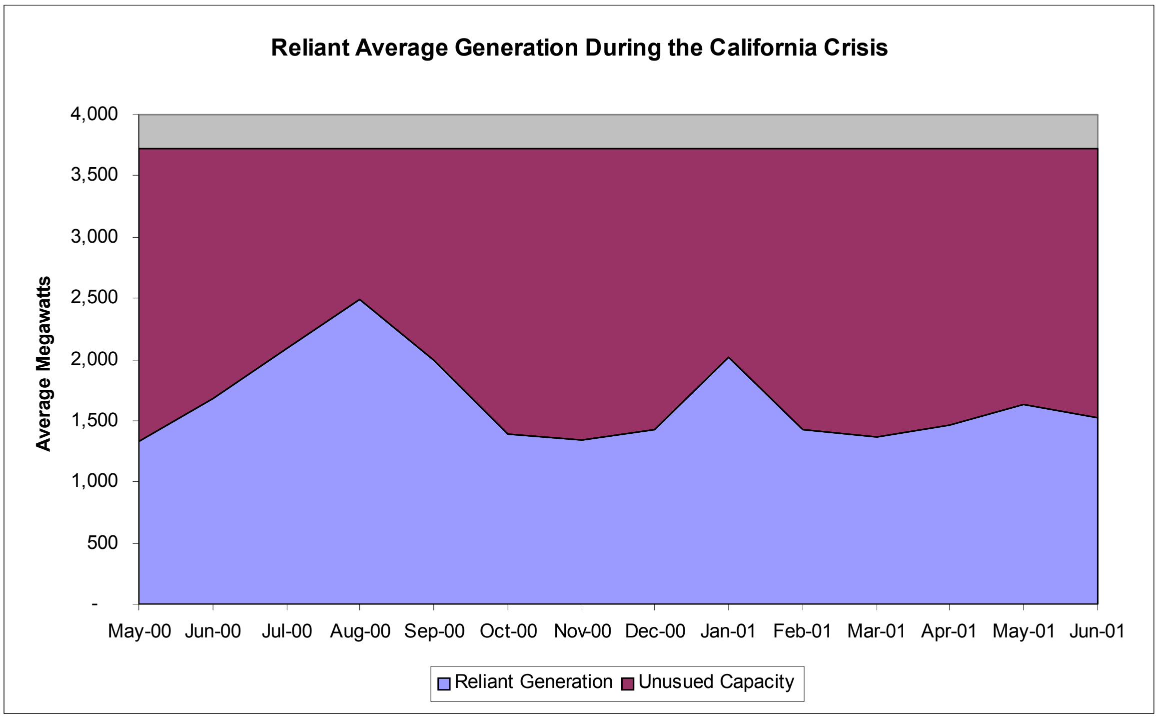
A. No. Similar plants, ownedby the same generators, are working effectively across the U.S. The age of these plants, in almost all cases, is comparable to similar plants elsewhere. The following chart summarizes data from a number of sources including the EIA plants database, NERC Generation Availability Data System (GADS), and materials from the divestiture EIS.[8]

[8](SEATAC-404).

Owner	Plant Name	Type of Fuel	Online Year	Age of Plant	US Average Age of Similar Plants	Average Age of Plants Owned by This Generator	Capacity	1995-1999 Availability	1999 Availability
Mirant	Contra Costa 6	Steam	1964	39	35	36	345	82.70%	83.70%
Mirant	Contra Costa 7	Steam	1964	39	35	36	347	82.70%	83.70%
Duke	Moss Landing 6	Steam	1967	36	26	34	767	81.10%	81.00%
Duke	Moss Landing 7	Steam	1968	35	26	34	768	81.10%	81.00%
Mirant	Pittsburg 1	Steam	1954	49	45	56	167	85.80%	85.40%
Mirant	Pittsburg 2	Steam	1954	49	45	56	163	85.80%	85.40%
Mirant	Pittsburg 3	Steam	1954	49	45	56	163	85.80%	85.40%
Mirant	Pittsburg 4	Steam	1954	49	45	56	163	85.80%	85.40%
Mirant	Pittsburg 5	Steam	1960	43	35	36	325	82.70%	83.70%
Mirant	Pittsburg 6	Steam	1961	42	35	40	325	82.70%	83.70%
Mirant	Pittsburg 7	Steam	1972	31	26	23	700	81.10%	81.00%
AES	Alamitos 1	Steam	1956	47	45	25	168	85.80%	85.40%
AES	Alamitos 2	Steam	1957	46	39	25	201	84.70%	82.40%
AES	Alamitos 3	Steam	1961	42	35	16	331	82.70%	83.70%
AES	Alamitos 4	Steam	1962	41	35	16	336	82.70%	83.70%
AES	Alamitos 5	Steam	1966	37	28	16	497	83.50%	81.30%
AES	Alamitos 6	Steam	1966	37	28	16	493	83.50%	81.30%
Reliant	Cool Water 1	Steam	1961	42	60	52	81	89.60%	88.30%
Reliant	Cool Water 2	Steam	1964	39	60	52	88	89.60%	88.30%
Reliant	Cool Water 3	Steam	1978	25	39	43	272	84.70%	82.40%
Reliant	Cool Water 4	Steam	1978	25	39	43	273	84.70%	82.40%
Dynegy	El Segundo 1	Steam	1955	48	45	48	188	85.80%	85.40%
Dynegy	El Segundo 2	Steam	1956	47	45	48	179	85.80%	85.40%
Dynegy	El Segundo 3	Steam	1964	39	35	39	354	82.70%	83.70%
Dynegy	El Segundo 4	Steam	1965	38	35	39	345	82.70%	83.70%
Dynegy	Encina 1	Steam	1954	49	45	48	107	88.80%	83.60%
Dynegy	Encina 2	Steam	1956	47	45	48	104	88.80%	83.60%
Dynegy	Encina 3	Steam	1958	45	45	48	110	88.80%	83.60%
Dynegy	Encina 4	Steam	1973	30	35	39	300	88.80%	83.60%
Dynegy	Encina 5	Steam	1978	25	35	39	330	88.80%	83.60%
Dynegy	Encina 6	Combustion	1968	35	23	53	16	88.80%	83.60%
Reliant	Etiwanda 1	Steam	1953	50	45	48	132	85.80%	85.40%
Reliant	Etiwanda 2	Steam	1953	50	45	48	140	85.80%	85.40%
Reliant	Etiwanda 3	Steam	1963	40	35	35	340	82.70%	83.70%
Reliant	Etiwanda 4	Steam	1963	40	35	35	336	82.70%	83.70%
AES	Huntington Beach 1	Steam	1958	45	39	25	233	84.70%	82.40%
AES	Huntington Beach 2	Steam	1958	45	39	25	251	84.70%	82.40%
Reliant	Mandalay 1	Steam	1959	44	39	43	227	84.70%	82.40%
Reliant	Mandalay 2	Steam	1959	44	39	43	227	84.70%	82.40%
Duke	Morro Bay 1	Steam	1956	47	45	48	171	85.80%	85.40%
Duke	Morro Bay 2	Steam	1955	48	45	48	174	85.80%	85.40%
Duke	Morro Bay 3	Steam	1962	41	35	38	347	82.70%	83.70%
Duke	Morro Bay 4	Steam	1963	40	35	38	355	82.70%	83.70%
Reliant	Ormond Beach 1	Steam	1971	32	26	29	794	81.10%	81.00%
Reliant	Ormond Beach 2	Steam	1973	30	26	29	792	81.10%	81.00%
AES	Redondo Beach 1	Steam	1948	55	45	25	185	85.80%	85.40%
AES	Redondo Beach 2	Steam	1948	55	45	25	165	85.80%	85.40%
AES	Redondo Beach 3	Steam	1949	54	28	16	497	84.40%	84.40%
AES	Redondo Beach 4	Steam	1949	54	29	16	503	84.40%	84.40%
Duke	South Bay 1	Steam	1960	43	45	48	160	85.80%	85.40%
Duke	South Bay 2	Steam	1962	41	45	48	158	85.80%	85.40%
Duke	South Bay 3	Steam	1964	39	45	48	187	85.80%	85.40%
Duke	South Bay 4	Steam	1971	32	39	43	238	84.70%	82.40%
Source	SCE Divesture information ELECTRIC_DIVESTITURE.XLS	SCE Divesture information ELECTRIC_DIVESTITURE.XLS	SCE Divesture information ELECTRIC_DIVESTITURE.XLS	2000 EIA Form 860A	2000 EIA Form 860A and January 2000 EIA Inventory of Nonutility Electric Power Plants in the United States 2000 January 2003	2000 EIA Form 860A	SCE Divesture information ELECTRIC_DIVESTITURE.XLS	NERC GADSReliability Data	NERC GADS Reliability Data

Q. How did the individual companies perform during system emergencies?

A. The following chart shows total capacity at Reliant's four largest units, Coolwater, Etiwanda, Ormond, and Mandalay throughout the duration of the California crisis.[9]



In spite of the gravity of the situation during the California crisis, Reliant only achieved average operating rates higher than the highest achieved in 1994 in one month – August 2000.

Q. What were plant availabilities for the five generators for Stage 1, Stage 2, and Stage 3 Emergencies?

A. The following charts show the plant performance across the 125 days or ISO declared

[9](SEATAC-405).

emergencies.[10]

Total AES Generation	MW		
Nameplate Capacity	3878		
Maximum Generation Observed, 2000-2001	3545		
		% of Capacity	% of Maximum
Average Generation, May 22, 2000 - July 3, 2001	1838	47.4%	51.9%
Average Generation, Stage 1 Emergencies	2035	52.5%	57.4%
Average Generation, Stage 2 Emergencies	2031	52.4%	57.3%
Average Generation, Stage 3 Emergencies	2034	52.4%	57.4%
Average Generation, January 17, 2001	1507	38.9%	42.5%
Average Generation, January 18, 2001	1608	41.5%	45.4%
Average Generation, July 4, 2001 - August 31, 2001	2335	60.2%	65.9%

Total Dynegy Generation	MW		
Nameplate Capacity	2034		
Maximum Generation Observed, 2000-2001	1925		
		% of Capacity	% of Maximum
Average Generation, May 22, 2000 - July 3, 2001	837	41.1%	43.5%
Average Generation, Stage 1 Emergencies	1087	53.4%	56.5%
Average Generation, Stage 2 Emergencies	1067	52.5%	55.4%
Average Generation, Stage 3 Emergencies	1029	50.6%	53.5%
Average Generation, January 17, 2001	1409	69.3%	73.2%
Average Generation, January 18, 2001	1130	55.5%	58.7%
Average Generation, July 4, 2001 - August 31, 2001	865	42.5%	44.9%

[10](SEATAC-402 and 406).

Total Duke Generation	MW		
Nameplate Capacity	3325		
Maximum Generation Observed, 2000-2001	3265		
		% of Capacity	% of Maximum
Average Generation, May 22, 2000 - July 3, 2001	2017	60.7%	61.8%
Average Generation, Stage 1 Emergencies	1939	58.3%	59.4%
Average Generation, Stage 2 Emergencies	1845	55.5%	56.5%
Average Generation, Stage 3 Emergencies	1706	51.3%	52.3%
			0.0%
Average Generation, January 17, 2001	1739	52.3%	53.3%
Average Generation, January 18, 2001	1863	56.0%	57.1%
			0.0%
Average Generation, July 4, 2001 - August 31, 2001	1953	58.7%	59.8%

Total Reliant Generation	MW		
Nameplate Capacity	3704		
Maximum Generation Observed, 2000-2001	3411		
		% of Capacity	% of Maximum
Average Generation, May 22, 2000 - July 3, 2001	1714	46.3%	50.3%
Average Generation, Stage 1 Emergencies	1905	51.4%	55.9%
Average Generation, Stage 2 Emergencies	1869	50.4%	54.8%
Average Generation, Stage 3 Emergencies	1916	51.7%	56.2%
Average Generation, January 17, 2001	2610	70.5%	76.5%
Average Generation, January 18, 2001	2611	70.5%	76.5%
Average Generation, July 4, 2001 - August 31, 2001	1642	44.3%	48.2%

Total Southern Generation	MW		
Nameplate Capacity	2698		
Maximum Generation Observed, 2000-2001	2679		
		% of Capacity	% of Maximum
Average Generation, May 22, 2000 - July 3, 2001	1587	58.8%	59.2%
Average Generation, Stage 1 Emergencies	1732	64.2%	64.7%
Average Generation, Stage 2 Emergencies	1681	62.3%	62.7%
Average Generation, Stage 3 Emergencies	1591	59.0%	59.4%
Average Generation, January 17, 2001	1312	48.6%	49.0%
Average Generation, January 18, 2001	1230	45.6%	45.9%
Average Generation, July 4, 2001 - August 31, 2001	1765	65.4%	65.9%

Q. What conclusion do you draw from this operating record?

A. All five generators, at different plants, in different locations, and facing different environmental rules all managed to fail to meet peak generation 40% to 50% of the time. Given the incentives available for full generation, this is a highly suspicious performance.

Q. How likely is it that all of these plants were facing outages during all of the emergencies?

A. Highly unlikely. A basic tool for evaluating complex questions of probability is the Monte Carlo model. It is straightforward to use such a model to check whether the operation of these plants was consistent with the plant availabilities shown in GADS.

Q. What is a Monte Carlo model?

A. Monte Carlo model simulates a large universe of different events in order to get a sense of the overall distribution of outcomes. For example, in order to see what the probabilities might be in a complex game involving dice, it might be efficient to ask the computer to run thousands of different "games" trying a different random set of dice throws for each game.

Plant availability calculations have often used a similar approach in order to get a sense of the distribution of the availability for a whole portfolio of different power plants.[11]

Q. For what types of problems are "Monte Carlo" studies most often applied?

A. Monte Carlo methods are most often applied to problems that defy simple closed analytical solutions, but they are also commonly used to convincingly demonstrate phenomena that may be difficult for reasonably intelligent people to understand in a rigorous mathematical way. Monte Carlo is also popular in the teaching of various kinds of mathematics, especially in problems relating to probability theory. Generally, Monte Carlo methods involve four ingredients/steps; first, the statement of a real-valued function of several variables, some of them random variables; second, the generation of values for all the variables, including many "draws" from the random variables; third, the calculation of the stated function for every set of values for the variables; and fourth, a statistical analysis of the behavior of the set of function values.[12]

Q. How did you apply Monte Carlo methods to answer the question of how likely would be the unavailability of 45% of the collective generating capacity of a particular set of power plants on any day?

A. In the instant problem of examining the joint availability factor for a set of generating plants, the Monte Carlo steps are implemented as follows:

First, define the variables and the function of interest. In the instant case, the variables are

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[11] Exhibit SEATAC-402 and 407.

[12] True Monte Carlo methods implement sophisticated strategies for reducing the variance of estimated values in simulation studies, e.g., stratified sampling. But in common parlance the term has long since come to refer to any simulation study that includes a realistic approach to random phenomena that involves the generation of values that can be treated as samples from a random variable.

the available generating capacity for each of the plants in a particular time period for which the plants' availability factors are relevant. For a particular day that a plant is not on maintenance outage, a plant can reasonably assumed to be either available or not available, with a likelihood of availability equal to the plant's availability factor. The relevant function is then the total available capacity in the pertinent time period, just the sum of the available capacities of each plant, divided by the total capacities of all the plants, available or not. That is, in a particular time period the value of the fundamental variables – each plant's available capacity – is either the normal capacity of the plant, or, if the plant suffers an outage, zero; and the function of interest is just the proportion that sum is of the total possible capacity of all the plants if they were all available.

Second, repeated samples of all the fundamental variables must be generated. In our application, each repetition or trial consists of one complete set of available capacities for the plants. For each plant, this can be accomplished by repeatedly simulating a simple yes-no process that generates yeses with a probability equal to a particular plant's availability factor; if the answer is "yes" then the plant's capacity is available, if "no" then the plants available capacity is zero. For example, a 100 MW plant with a 75% availability factor will offer 100 MW of capacity for, on average, 75 out of 100 occasions that it is called on for service. This kind of behavior is easy to simulate with a computer and can be easily imagined as the throwing of dice or coins, or the operation of simple machines as seen on "Wheel-Of-Fortune."

Third, the function of interest is the total capacity available in each time period. Our application is implemented by simply adding up the simulated available capacities of all the plants, once for each time period. Some plants are “available” and contribute their total capacity to this sum, while others are “unavailable” and add zero.

Fourth, the statistical distribution of the variable of interest is evaluated. In our application, we have a particular interest in the probability that the total available capacity is less than some particular proportion of the total possible capacity. As a statistical statement, we are looking for the value of a probability distribution function at a particular availability percentage.

Q. Are there other problems that clearly illustrate how this approach works in evaluating the likelihood of complex events?

A. An analogous problem is the question of how likely it is to roll ten dice simultaneously, assign a value of zero to a die if it comes up six and a value of one otherwise, add up the values and get a total less than or equal to five. This problem can be solved analytically, but is easily explored by just throwing ten dice many times and tabulating the results. The problem is more difficult to solve analytically if the dice have different numbers of faces – e.g. a mix of normal cubical dice, octrahedral dice, tetrahedral dice – and the values assigned to each die are different functions of how the die falls, and if there are many more dice. In that case, a convincing demonstration can still be made by actually conducting the experiment, throwing the dice many times and keeping tabs on the results.

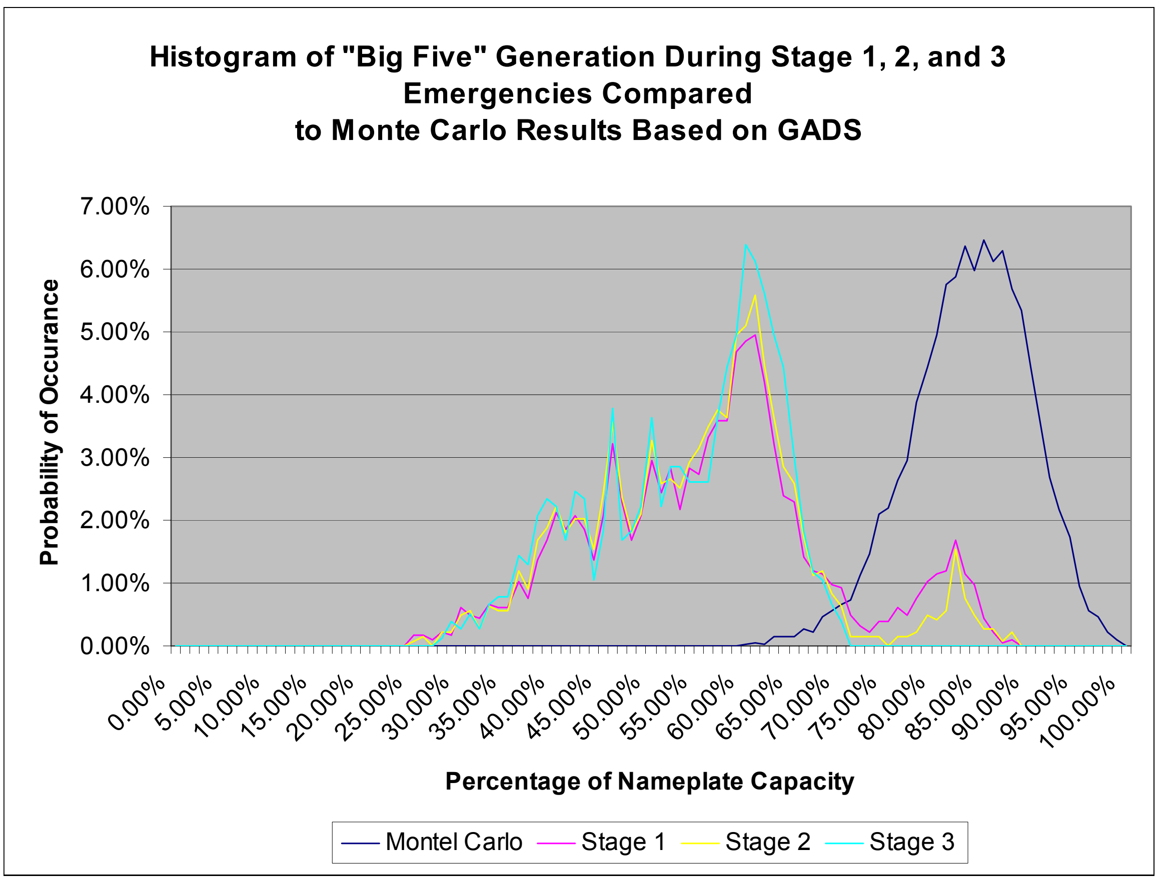
Q. How would this roll-of-the-dice example relate to the study you performed?

A. The capacity availability Monte Carlo study we performed involved ten thousand “throws of the dice.”

Q. How likely would the real world capacity availability for these plants be if the simple

assumptions of your Monte Carlo study, as represented by the plant owners, were true?

A. The actual total availability on many occasions/days for the real plants in the real world was so much lower than *any* occasion in our simulation that the assumptions of the simulation must be called into question. The only relevant assumptions in the simulation were the stated availability factors. The availabilities must be considerably lower than those stated to get any observations matching reality at all, let alone with the frequency reported for the relevant historical period.



Q. What does the Monte Carlo study show?

A. The bell shaped curve to the right shows the distribution of plant operations simulated by running each of the plants ten thousand times. In each iteration the plant is modeled as being available if the random number chosen by the computer is less than the availability rate taken from GADS. Contra Costa 6, for example, is available 82.7% of the time on average, but it will be placed out of service depending on the random number chosen in each game.

The blue line is the distribution of generation during Stage 3 Emergencies during the California crisis. Ten thousand iterations provide an average availability in the 85% range. Average availability of the generator's units during Stage 3 Emergencies was a surprisingly low 52.9% of nameplate capacity.

Q. How did you approach the problem of dispatching the units?

A. The first step is to calculate the operating cost for the units for each hour. As opposed to the assumed NOx prices and NOx/kWh ratios, we used actual experienced prices and rates. Natural gas prices were taken from actual market data.

Each one of the units purchased by the five generators from SDG&E (San Diego Gas & Electric), SCE (Southern California Edison), and PG&E (Pacific Gas &Electric) are modeled separately. We obtained our NOx prices directly from the RECLAIM bulletin board. When months are missing, we used the average of prices for the remainder of the cycle since the opportunity cost of current use is the loss of the RECLAIM credits in later months.

The results are:[13]

	Northern California aMW	Southern California (Outside of SCAQMD) aMW	SCAQMD aMW	Total aMW
Forecasted				
Jan-97 to Mar-98	539.93	490.59	498.96	1,529.48
Apr-98 to Apr-00	1,721.49	1,825.26	1759.91	5,306.66
May-00 to Jun-01	3,359.74	3,937.84	3621.50	10,919.07
Jul-01 to Dec-01	2,220.81	2,466.26	1472.16	6,159.22
Jan-02 to Sept-02	1,032.08	1,183.69	945.39	3,161.16
Actual				
Jan-97 to Mar-98	1,252.64	1,139.20	1060.72	3,452.56
Apr-98 to Apr-00	1,316.20	1,386.62	986.31	3,689.14
May-00 to Jun-01	2,578.61	2,768.38	2452.82	7,799.81
Jul-01 to Dec-01	2,233.29	2,136.41	2273.95	6,643.65
Jan-02 to Sept-02	1,221.76	1,341.16	1311.54	3,874.46
Difference				
Jan-97 to Mar-98	712.71	648.61	561.76	1,923.08
Apr-98 to Apr-00	(405.28)	(438.63)	(773.61)	(1,617.53)
May-00 to Jun-01	(781.13)	(1,169.46)	(1,168.67)	(3,119.26)
Jul-01 to Dec-01	12.49	(329.85)	801.79	484.43
Jan-02 to Sept-02	189.68	157.47	366.15	713.30

[13] Exhibit SEATAC-402 and 408

Over the period of the crisis, generation from the Big Five units is 3,119 megawatts lower on average than what we would have expected from a decision to dispatch into the market based on a comparison of market prices to plant operating costs. It is interesting to note that the shortfall takes place throughout California, even in areas that were not subject to the NOx market in the L.A. basin.

Q. How does this analysis treat forced outages?

A. The incomplete accounting of outages at the California ISO as well as the transcripts from AES, Williams, and Reliant do not create much confidence in the reliability estimates provided by either the ISO or the generators.

Our approach is exceedingly conservative. We have derated the plants in our study by the corresponding equivalent availability factors (EAFs) from GADS from 1995 to 1999. In practice, this means that we have assumed that the generators were as likely to schedule planned outages during the summer as the winter and to make repairs on-peak as well as off-peak. Clearly, this is not true in the real world.

Q. Are there other conservative elements in your analysis?

A. Yes. The simple dispatch model we have developed does not consider ramping. In practice, this means that we consistently underestimate off-peak hours where the practice of such units is to maintain a minimum operating level. In our model, we have assumed that the unit can be taken to zero and then returned to full operation. Obviously, these plants ramp up during off-peak in order to generate for high costs during on-peak hours.

Q. How did you model the change in SCAQMD policy towards pricing RECLAIM

emissions credits that occurred in January?

A. After discussions with SCAQMD personnel and a careful review of the RECLAIM data, we treated the cost of credits as $7.50/pound. Since SCAQMD split the market into two parts and allowed electric generators to purchase their requirements over their allocations at $7.50/pound in January, this is the logical economic cost.

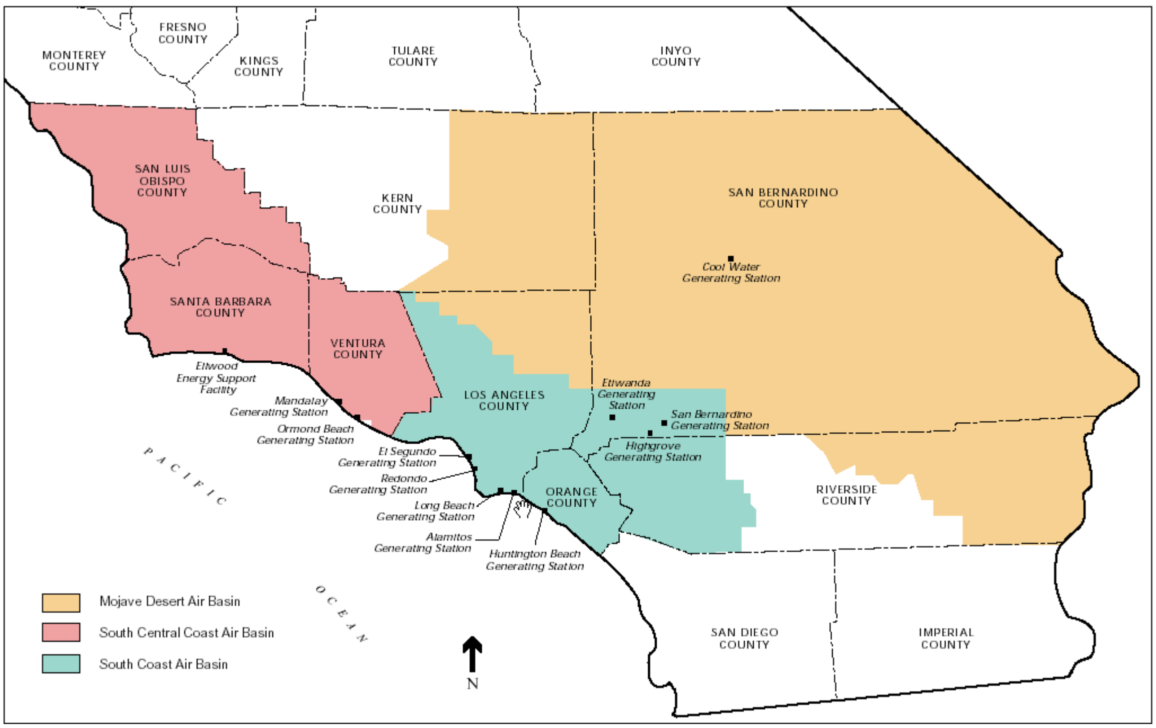
Q. Why were operations at these plants under utility ownership higher than your model predicted?

A. Before April 1, 1998, California's wholesale markets were simpler, but they were not free from market power. Traditionally, three buyers, Pacific Gas and Electric, Southern California Edison, and San Diego Electric and Gas dominated the import market from the Pacific Northwest. On the seller side of the market, over twenty different entities were attempting to sell their non-firm electricity. This is a classic definition of oligopsony – a large number of sellers facing a small number of buyers. Buyers reacted to this market advantage by buying less than they would normally have purchased as part of their negotiating strategy. Thus we would expect the plants to have operated more than a simple dispatch model would predict during this period. After the startup of the ISO and PX, the three utilities no longer had market power, instead they purchased power through the PX and divested the large thermal units.

Q. Have you reviewed the specific case of the Reliant withholding reported in the Reliant transcripts?

A. Yes. As part of California's divestiture policy, Southern California Edison sold four major plants to Reliant in 1998. The four plants, Ormond Beach, Etiwanda, Cool Water, and

Mandalay, totaled 3,704 megawatts, approximately 6% of California's generation. The plants are neither modern nor terribly efficient, but they are representative of a broad class of similar units across the United States. While much has been made of their age, comparable units in the North American Electric Reliability Council's Generation Availability Data Set (NERC's GADS) have a good history with availability in the 80% range. These plants are approximately the same age as other units in the NERC data.



FERC's February 1, 2001 report summarized Reliant's portfolio as:

Facility	Unit	Type	Net Summer Capacity (MW)	Commercial Operating Date	Age	Location
Ormond Beach	Unit 1	Thermal	750	1971	30	California
	Unit 2	Thermal	750	1973	28	
			1,500			
Etiwanda	Unit 1	Thermal	132	1953	48	California
	Unit 2	Thermal	132	1953	48	
	Unit 3	Thermal	320	1963	38	
	Unit 4	Thermal	320	1963	38	
	Unit 5	GT	126	1969	32	
			1,030			
Coolwater	Unit 1	Thermal	65	1961	40	California
	Unit 2	Thermal	81	1964	37	
	Unit 3	GT CC	241	1978	23	
	Unit 4	GT CC	241	1978	23	
			628			
Mandalay	Unit 1	Thermal	215	1959	42	California
	Unit 2	Thermal	215	1959	42	
	Unit 3	GT	130	1971	30	
			560			
Ellwood	Unit 1	GT	48	1974	27	California
El Dorado	Unit 1	GT CC	123	2000	1	Nevada
	Unit 2	GT CC	123	2000	1	
			246 *			
TOTAL MW			4,012			

* Represents Reliant's 50 percent share of a jointly-owned project.
GT - Gas Turbine
CC - Combined Cycle

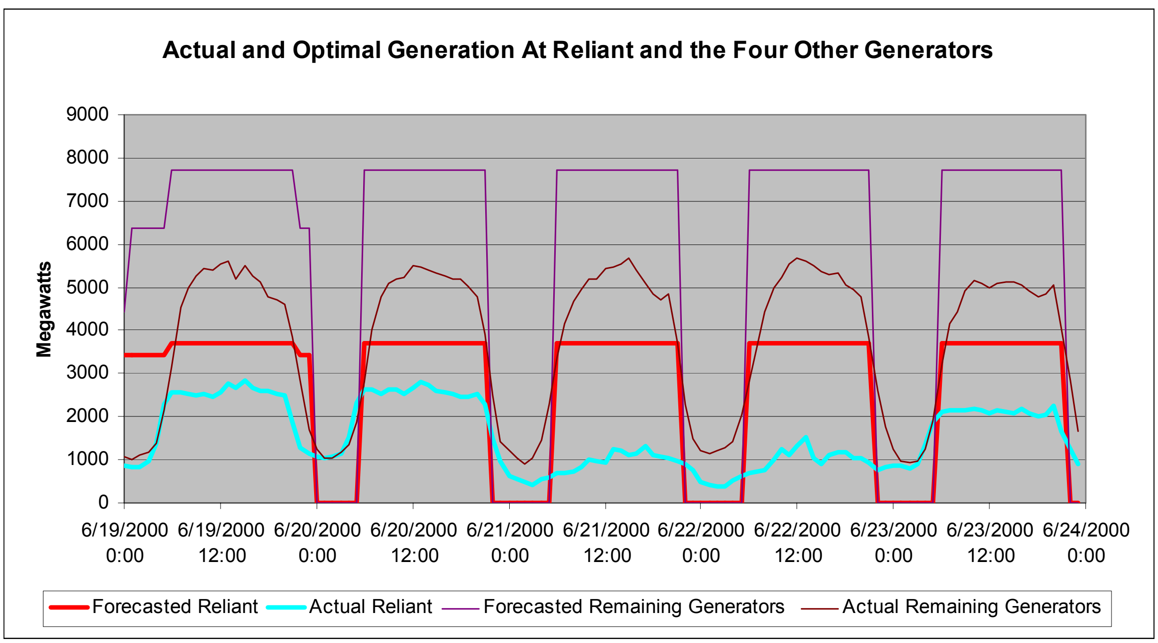
Heat rates for the four large units range from 9,300 MMBTU/kWh to 11,000 MMBTU to kWh. Only one of the plants, Etiwanda, is exposed to the South Coast Air Quality Management District's Reclaim emissions allowances market.

Operation of Reliant's plants during the California crisis was poor, but roughly comparable to its four competitors, Duke, Dynegy, Mirant, and AES/Williams.

Public data concerning actual outages is limited. ISO data for half of the crisis (2000) is incomplete. Reliant has released data on their "fleet" showing availability rates of 70% in 2000 and 78% in 2001. Obviously, the contrast between the low levels of generation and the relatively high levels of availability is marked.

Q. Have you analyzed the operation of Reliant's units using the dispatch model summarized above?

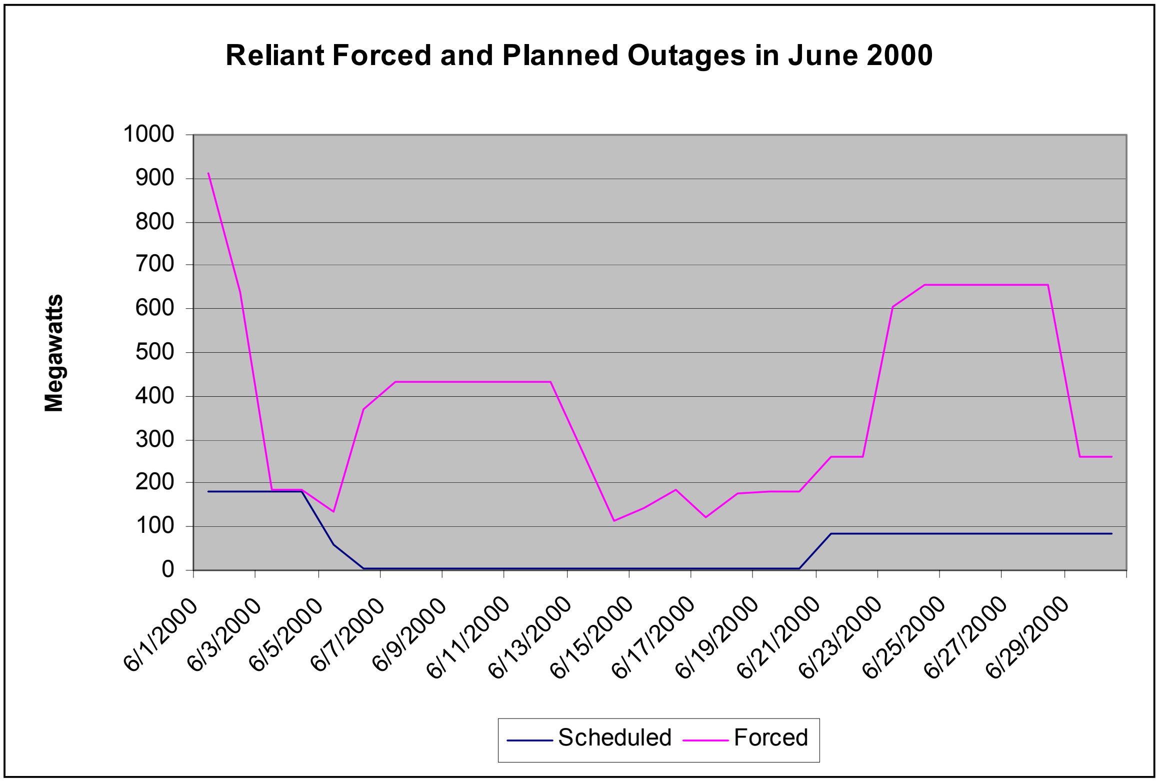
A. The following chart shows expected and actual generation for Reliant and the other four generators:[14]



The withholding described in the transcripts refers to the reduction in production from 2500 MW on June 19 and 20 to approximately 1000 MW on June 21 and 22. Outages

[14]Exhibit SEATAC-402 and 409.

reported to the ISO for June tells an interesting story. According to the ISO reports, the days identified in the FERC settlement were among the best days Reliant plants saw that month.[15]



Q. Were these reductions financially beneficial?

A. These reduction were not without cost. If Reliant had operated their plants at the rated capacity during on-peak hours on June 22, they would have netted $1,072,261 in additional profit. Operating at less than rated capacity on June 21, cost them an additional $858,557 in profits.

Q. Is there evidence that Reliant repeated this withholding behavior?

---

[15]Exhibit SEATAC-402 and 409.

A. Yes. It is relatively easy to check if Reliant frequently made large unexplained shifts in generation over the period of the California crisis. Since we know the changes their generation levels should have made with respect to electric prices, natural gas prices, and NOx prices, we can easily identify sudden shifts that can not be explained by these factors. We can expect that major shifts are unlikely to be explained by a real outage, since this would require multiple units to fail simultaneously.

The next chart shows large daily shifts in Reliant generation after changes in market conditions have been considered.[16] For example, a sudden shift in gas prices would normally induce generators to reduce output. These changes have been factored into the analysis – as have changes in other critical prices.

Date	Unexplained Reduction In Generation
12/11/2000-12/09/2000	(2,695)
11/27/2000-11/25/2000	(2,097)
06/21/2000-06/20/2000	(1,573)
01/02/2001-01/01/2001	(1,360)
05/22/2000-05/20/2000	(1,105)
11/28/2000-11/27/2000	(1,016)
10/07/2000-10/06/2000	(1,003)
12/13/2000-12/12/2000	(780)
05/28/2001-05/26/2001	(756)
07/15/2000-07/14/2000	(738)
01/04/2001-01/03/2001	(693)
05/04/2001-05/03/2001	(687)
07/08/2000-07/07/2000	(678)
06/01/2001-05/31/2001	(663)
09/01/2000-08/31/2000	(658)
06/28/2001-06/27/2001	(637)
12/04/2000-12/02/2000	(571)
06/03/2000-06/02/2000	(561)

As can be readily seen, Reliant generation often exhibited large changes that could not be

[16]Exhibit SEATAC-402 and 411.

explained by market conditions. In each case, Reliant's generation reduction was enormously costly by traditional business standards. Given the transcripts, it is difficult to take Reliant's outage reports at face value and we know that reported outages on 6/21/2000 were reduced from previous days in June. The largest single shaft risk is 750 megawatts, so if outages were the answer, the reductions on 12/1/2000, 11/27/2000, 6/21/2000, 1/2/2001, 11/28/2000, and 12/13/2000 would represent forced outages simultaneously at more than one unit. The reduction on 6/21/2000, of course, is the subject of the transcripts released by FERC.

Q. Do any documents show that Enron practiced "schemes" to manipulate the market?

A. On December 6, 2000, two junior lawyers working for Enron wrote a memo to Richard Sanders, Enron's regulatory attorney for California, describing a long set of schemes and evaluating whether they were illegal.[17] On May 6, 2002 FERC released three memos that gave an overview of a family of schemes designed to take advantage of the ISO's rules.

Q. What schemes are identified in the Yoder/Hall memo?

A. The Yoder/Hall memo identifies a large number of schemes. These include:

Fat Boy:	Overscheduling energy to non-existent loads
Exports:	Purchasing power in California for external resale
Non-firm Export:	Scheduling for congestion charges and then canceling the schedule before flows actually occur
Death Star:	Scheduling flows south and then back north in order to fraudulently earn congestion payments

[17] 'Traders' Strategies in the California Wholesale Power Markets/ ISO Sanctions, Christian Yoder and Stephen Hall, December 6, 2000, Exhibit SEATAC-8.

Load Shift:	Fraudulently changing schedules to profit from congestion payments
Get Shorty:	Selling reserves to the ISO that Enron had not yet procured
Wheel Out:	Scheduling through closed transmission for congestion payments
Ricochet:	Scheduling power out of California in order to re-import to the state to evade price caps
Misrepresenting Non-firm and firm:	Selling power to California as firm that can be interrupted by the actual supplier
Collecting congestion payments for undelivered energy:	Schedules designed to collect congestion payments without actual supplies

Q. Were these schemes only practiced by Enron?

A. No. Certain Enron schemes, like Death Star, were very common. Other schemes, such as Fat Boy, also appear to be very prevalent.

Q. Was Enron the only party that provided to FERC a detailed description of the kind of schemes described in the Enron memoranda?

A. No. In an attachment to their PA02-2-000 affidavit,[18] At least one other party is known to have provided an equally detailed description of several schemes, including Death Star and

[18]See Attachment IIB, Exhibit SEATAC-412 (contains protected materials).

the sale of phantom ancillary services.

Q. Were there any reasons for confidential treatment of this document?

A. No. The document simply is a restatement of the Enron schemes with somewhat more precision.

Q. What is the significance of the Coral document?

A. It establishes that the understanding of the vulnerabilities of the California ISO and California PX was not reserved for Enron alone. The existence of the document goes far to explain the breadth of certain schemes, such as Death Star.

Silver Peak

Q. When did the schemes begin?

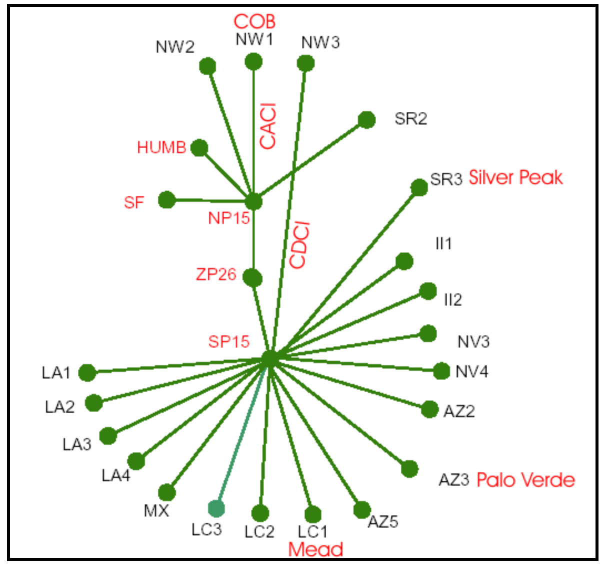
A. We do not know. The first major scheme for which we have evidence was launched on May 24, 1999, when Enron Power Marketing Incorporated (EPMI) submitted four bids into the California Power Exchange (PX) for 2,900 megawatts during on-peak hours. The path identified for the power to be sold was the Silver Peak line from Nevada. Ratings for Silver Peak vary, but the consensus appears to be that the line had a capacity of 15 megawatts. This impossible schedule went largely unnoticed by the California Independent System Operator (ISO), but two complaints spurred an investigation by the PX compliance unit.[19] The investigation dragged on for twelve months, and, in spite of a finding that Enron had cost consumers $4.6 million to $7 million, was settled for a fine of $25,000 and a commitment by Enron to not "substantially repeat" the behavior. We now know that Enron had taken a financial reserve of $10 million for a scheme they convinced

[19]California PX Silver Peak Investigation, May 22, 2001, Exhibit SEATAC-422.

the California PX brought Enron no profits.[20]

Q. What is "Silver Peak"?

A. The Silver Peak line consists of two 55 kV lines that stretch from the town of Silver Peak into California. It was built to facilitate generation at a Nevada geothermal unit. While the theoretical landscape of the California ISO allows it to be treated as an intertie, its actual operation is closely tied to this one power project. The line not capable of carrying more power than the project's generation.[21]



Q. Please describe the Silver Peak scheme.

On May 24, 1999, at 6:10 A.M., Enron submitted four bids of 725 megawatts for the heavy load hours of May 25th at prices from $18 to $20 per MWh.[22] An hour later, the California PX notified Enron that it was the successful bidder.[23]

At 7:29 A.M. Enron identified Silver Peak as the delivery point for the energy.[24] At 11:17 A.M. the California ISO called Enron to ask if the bid (and delivery point) were in error.[25] The conversation makes it clear that the ISO's reaction had been expected:

[20]Sch. C Report, Email from Samantha Law to Tim Belden, March 9, 2001, at 5, Exhibit SEATAC-420.
[21]Map available at http://www.caiso.com.
[22]California PX Silver Peak Investigation, May 22, 2001, at 27, 35, Exhibit SEATAC-422.
[23]*Id*. at 27, 35.
[24]*Id*. at 27, 35.
[25]ISO Transcript of ISO/Enron call on May 24, 1999, Exhibit SEATAC-415.

TIM: Um, there's a -- there -- we. just, um -- we did it because we wanted to do it. And I don't -- I don't mean to be coy.

KAREN: 'Cause, I mean, it's -- it's -- it’s a -- I mean --

TIM: It’s probably --

KAREN: -- it's a pretty interesting schedule.

TIM: It -- it's how we -- it makes the eyes pop, doesn't it?

KAREN: Um, yeah. I'll probably have to turn it in ‘cause it's so odd.

TIM: Right.[26]

The ISO triggered CONG, their congestion model, which, in turn, accepted the adjustment bids filed by Enron. The Power Exchange had provided a balanced schedule to the ISO. Once the congestion on Silver Peak was taken into account, the PX schedule was 2,885 megawatts below projected loads. The ISO balanced the loads by increasing imports, using reserves, and providing considerably higher prices back to the PX. The higher PX prices reduced day-ahead loads.[27]

Q. What was the impact of Enron’s actions?

Since actual loads did not change, the primary impact of the Silver Peak incident was to increase imports and to move loads from the day-ahead market to hour ahead markets and the ISO. The ISO’s estimates of the market adjustments were:

Source	MW
Needed Adjustment to Silver Peak	2,897
Increased Import from other Branch Groups	1,038

[26]*Id*. at 2.
[27]California PX Silver Peak Investigation, May 22, 2001, at 28, 36, Exhibit SEATAC-422.

Internal Production Increases	182
Internal Load Decreases	1,676[28]

The line entitled, "Internal Load Decreases," is a misnomer. The increased price at the PX from the distortion caused the supply curve to meet the demand curve at a lower level – 1,676 MW lower. While this has been labeled as "underscheduling" by the California utilities, the situation is a bit more complex. The California utilities priced their bids into the PX based on the opportunity cost of ISO real time replacement costs. If the costs were too high, as was the case here, the nature of the PX bid left it for the ISO to make up the differential from reserves and real time purchases.

Q. Were these actions observable?

A. The ISO market surveillance unit apparently did not notice the excursion. However, the market immediately observed what had happened.[29] The Energy Market Report for the 25th noted:

> B. Speaking of the PX, much of the hubbub on Tuesday surrounded the $44/MWh congestion adjusted prices. Rumors circulated that an unnamed party had manipulated the PX on Monday by bidding 3000 MW of power on a 20 MW line between Nevada and California. Someone played a game yesterday which caused everyone's adjustment bid schedules to come into play, and that resulted in the higher prices throughout the system," said one market pundit. Other

---

[28] Analysis of Possible Day-Ahead Congestion Gaming, ISO Market Analysis Department, June 1999, at 3, Exhibit SEATAC-416.

[29] The ISO Weekly Market Watch's only mention of the Silver Peak incident was a statement that "Price spikes of $177/MW and $162/MW occurred on May 25 at hours ending 1600 & 1700 due to significant incremental energy requirements that exceeded 2400 MW," Exhibit SEATAC-417.

> players did not believe that someone could consciously manipulate PX prices from a UMCP of $27.25/MWh to an adjusted price of $44.31/MWh, and blamed human error for the high price. Nonetheless, sources indicated that the PX was going to look into the matter to determine if "market manipulation" had actually taken place.[30]

In the course of the subsequent investigation of this event, the Power Exchange staff estimated that the Silver Peak incidents cost consumers $4.6 million to $7.0 million. They also estimated that Enron lost $102,000 in the day-ahead market as a result of the imaginary resource bid.[31]

Q. Was that a reasonable estimate?

A. I do not believe so. We now have evidence that Enron had engineered a considerable profit from this one scheme. Tim Belden's financial reserves for west coast trading are contained in a form called "Schedule C." Schedule C contains reserves for a number of different schemes including selling non-firm energy as firm. It also contains two entries on Silver Peak:

> Cover potential liability associated with scheduling at Silver Peak on May 24, 1999. $4,000,000
>
> Increase reserve associated with PX schedule at Silver Peak. Reserve for total

---

[30] Energy Market Report, May 25, 1999,at 1, Exhibit SEATAC-418.

[31] Report on the Compliance Unit Investigation of Market Events for May 25, 1999, page 5. The PX investigative staff also "accepts Enron's statements that it had no other arrangements outside of the CalPX markets from which it profited financially as a result of its actions," Exhibit SEATC-422.

potential in Day Ahead & Real Time markets, includes actual damages & opportunity cost. $6,000,000[32]

The implication is that Enron cleared $10 million from the scheme, not losing a small amount as they had argued during the PX investigation.

Q. Why, in your opinion, did Enron take the risk of Silver Peak?

A. It is my opinion that this was a "proof of concept" scheme designed to see what happened when energy was removed from the PX markets.

Q. Does the Silver Peak episode resemble any aspect of the subsequent California crisis?

A. Yes. It closely resembles the first day of that crisis – May 22, 2000.

Q. Please explain.

A. In both cases vast amounts of potential on-peak energy were withdrawn from the California PX with a significant impact on energy prices in California, and through surrounding markets, the length and breadth of the WSCC. In Silver Peak the shortage was arranged by sending imaginary power into the California PX. In the course of the May 22, 2000 emergency, a similar amount of power was withdrawn from the PX using the Fat Boy scheme.

[32]Schedule C Summary as of May 14, 2000, Exhibit SEATAC-420.

Enron's traders developed a number of finely tuned schemes that manipulated the California ISO's computer systems in order to receive congestion fees. The schemes appear to be simple commercial fraud since, by design, no actual generation was ever envisaged as running to support the schedules filed with the California ISO. One scheme in particular, the Forney Perpetual Loop,[33] is designed to create an illusion of power flowing in a circle from John Day in Oregon through Mead in Nevada, through the critical congested pathways in California, without any input of energy whatsoever.

Each of these schemes is a subset of the generic scheme, Death Star, where an imaginary schedule is filed with the ISO that elicits payments for the alleviation of congestion. Since the ISO is rule based rather than results based, no actual generation is required for the right to file schedules. The only issues within the ISO pertained to whether the schedules met the rules – even if they failed to meet any engineering logic.

Each scheme is based on the fact that schedules are only plans that are filed days and hours before energy flows take place. This allowed Enron to create an imaginary cycle of trades through the ISO. A good analogy to this scheme is the common form of financial fraud known as "check kiting." In this fraud, a con man writes checks between a cycle of bank accounts. The frequent deposits and withdrawals lull the bank into believing that real transactions are taking place. Eventually, the con man withdraws all the deposits at once, leaving the bank to discover that recently deposited checks will bounce since the accounts they were written on have been closed.

Enron knew that the schemes had enough counterparties that the ISO would not know that

[33]John Forney's Perpetual Loop Diagram, Exhibit SEATAC-421.

no energy actually flowed.

Schedules and Flows

Q. Do the Yoder/Hall schemes generally involve "real" flows of electricity?

A. No. The Yoder/Hall schemes are designed to manipulate schedules – primarily the computer files depended upon by the California ISO – and not flows.

Q. Did schemes like Death Star actually change the flows of electricity?

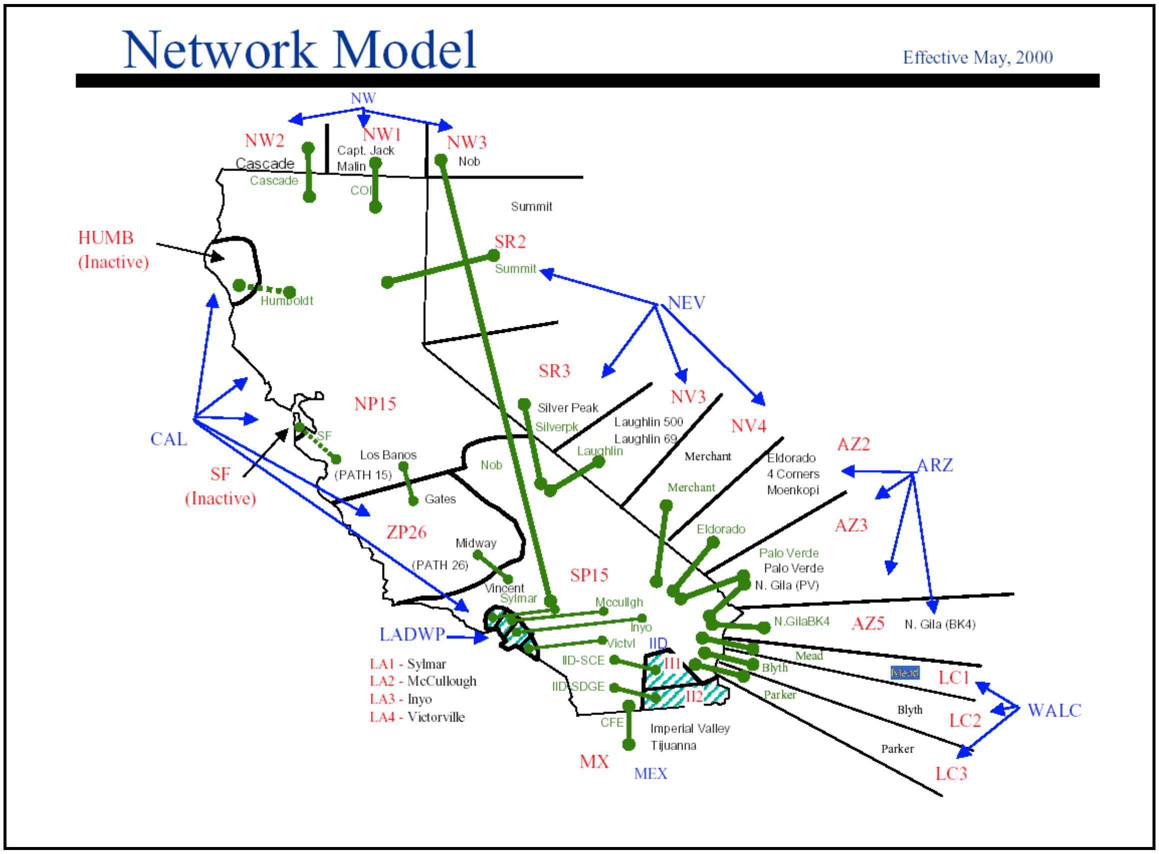
A. No. A central facet of the California ISO was the attempt to automate as much of this process as possible. Generators and consumers file schedules a day ahead. The ISO compares these schedules with transmission constraints and develops a feasible schedule of generation that matches the capacity of the transmission lines between the generating plants and the ultimate consumer.

Congestion fees are designed to induce generators to reduce their use of transmission lines that would otherwise carry flows greater than their rated capacity. Congestion fees are a product of schedules – no actual electricity flows until real time. In theory, the ISO will have adjusted the schedules to transmission constraints hours before actual operations commence.

Flows are instantaneous. We measure flows after the fact. If the system works, no congestion – use of transmission lines over their rated capacities – ever occurs in the real world. Obviously, in the very rare case when a mistake is made, lines overheat and equipment might fail. This could lead to wide spread blackouts since failure can easily be catastrophic. If the system looks like it will be overloading the transmission system, operators will order temporary rotating blackouts of limited size to avoid the possibility of catastrophic failure. This, apparently, is what occurred in the winter of 2000/2001. The California ISO's use of congestion fees to manage schedules is entirely a theoretical operation. The ISO's CONG computer program calculates the degree of congestion and derives the appropriate level of payment to induce generators to adjust their proposed generation schedule to the needs of the transmission system. After CONG has been run and the adjustments to schedules calculated, the operators can enter "real time" knowing that the basic operation of the system is consistent with the physical constraints of the transmission lines.

Q. Are these schemes easy to explain and measure?

A. No. The problem is compounded by the complexity of ISO terminology. The following diagram shows both the ISO's basic areas and the transmission routes that connect them. The specific locations that are central to the Death Star schemes are indicated both in ISO terminology and in more traditional industry defined geographic names.



The schedules of importance to Death Star and its related schemes are those that flow over the COI in the north, the flows between San Francisco and Los Angeles (NP-15 and SP-15) and lines to the east which allow imports from the Desert Southwest – Silver Peak, Mead, and Palo Verde.[34]

Death Stars

Q. Please describe the "Death Star" strategy.

A. In essence, a Death Star is any set of schedules that offset each other, using two or more different systems on which to file these schedules. The basic ingredients in a complete "Death Star" are offsetting import and export schedules on the ISO system, combined with

[34]Map available at http://www.caiso.com.

offsetting import and export schedules on another system. While it is possible that this second set of schedules could go entirely around the ISO system (e.g., scheduling through Utah or Colorado), by far the more common and convenient approach was to use other existing transmission contracts (ETCs) in California, such as those owned by various California municipal utilities.

The detailed materials authored by Michael Driscoll on April 5, 2000 describe how the hints in the Yoder/Hall memorandum actually worked. The following operating details are from his email:

> Project Death Star has been successfully implemented to capture congestion relief across paths 26, 15 & COI .
>
> We input the deals as follows :
>
> 1 EPMICAL POOL MEAD230 / MALIN
>
> 2. ONE DEAL TICKET, A BUY/RESALE WITH WASHINGTON WP SELLING AT MALIN, REPURCHASING AT PGE SYSTEM, (PAYING WWP $1 DIFFERENTIAL)
>
> 3. SELL INDEX FWD TO PGE AT PGE SYSTEM. INPUT AT DOW JONES MID C INDEX.
>
> 4. BUY INDEX FWD FROM PGE AT JOHN DAY AT DOW JONES MID C INDEX PLUS .90
>
> 5. USE EXISTING PGE CONTRACT #146517 FOR TRANSMISSION FROM JD/MALIN
>
> 6. USE EXISTING LADWP TRANSMISSION #292672 FROM

> MALIN>MEAD230
>
> Everything will link up, with the buy from PGE(JD) on top, all the trans and buy/resells in the middle, and the sell to PGE(system) at the end[35]

These are instructions on how to enter a Death Star transaction into Enron's scheduling computer program. Much of the shorthand involves instructions on the entry of the transaction into Enpower (Enron's California transaction software) or CAPS (software to submit schedules to the ISO.)

The six steps translated into normal English are as follows:

1. File a schedule over ISO transmission paths from Mead to the California Oregon Border.[36]
2. Washington Water Power (Avista) sells at COB and repurchases at Portland.

3/4. Enron buys and sells based on Dow Jones Mid C Index.

5. PGE transfers the power to John Day.
6. Transfer the power back to Mead over LADWP existing transmission rights on the ISO system.

This transaction will make it appear that energy is being exported out of California to the Pacific Northwest.[37] This will "capture" congestion fees at Path 15, Path 26, and the California Oregon Intertie. For this to work, power flows must be generally southward – a

[35] The FINAL PROCEDURES FOR DEATH STAR, disregard the other 2 emails, Michael Driscoll, May 5, 2000, Exhibit SEATAC-423.

[36] Malin is the physical location of the substation that connects PGE and BPA's 500 kV lines with California. Mead (not "Lake Mead") is a market hub in Nevada.

[37] An interesting facet to each of these schemes is that Enron was certain that the ISO would not connect the dots in these transactions. This is all the more surprising since the ISO schedules both sides of the transaction. Only the portions at Mead and within Oregon are outside of the ISO's scheduling.

standard situation in May.[38]

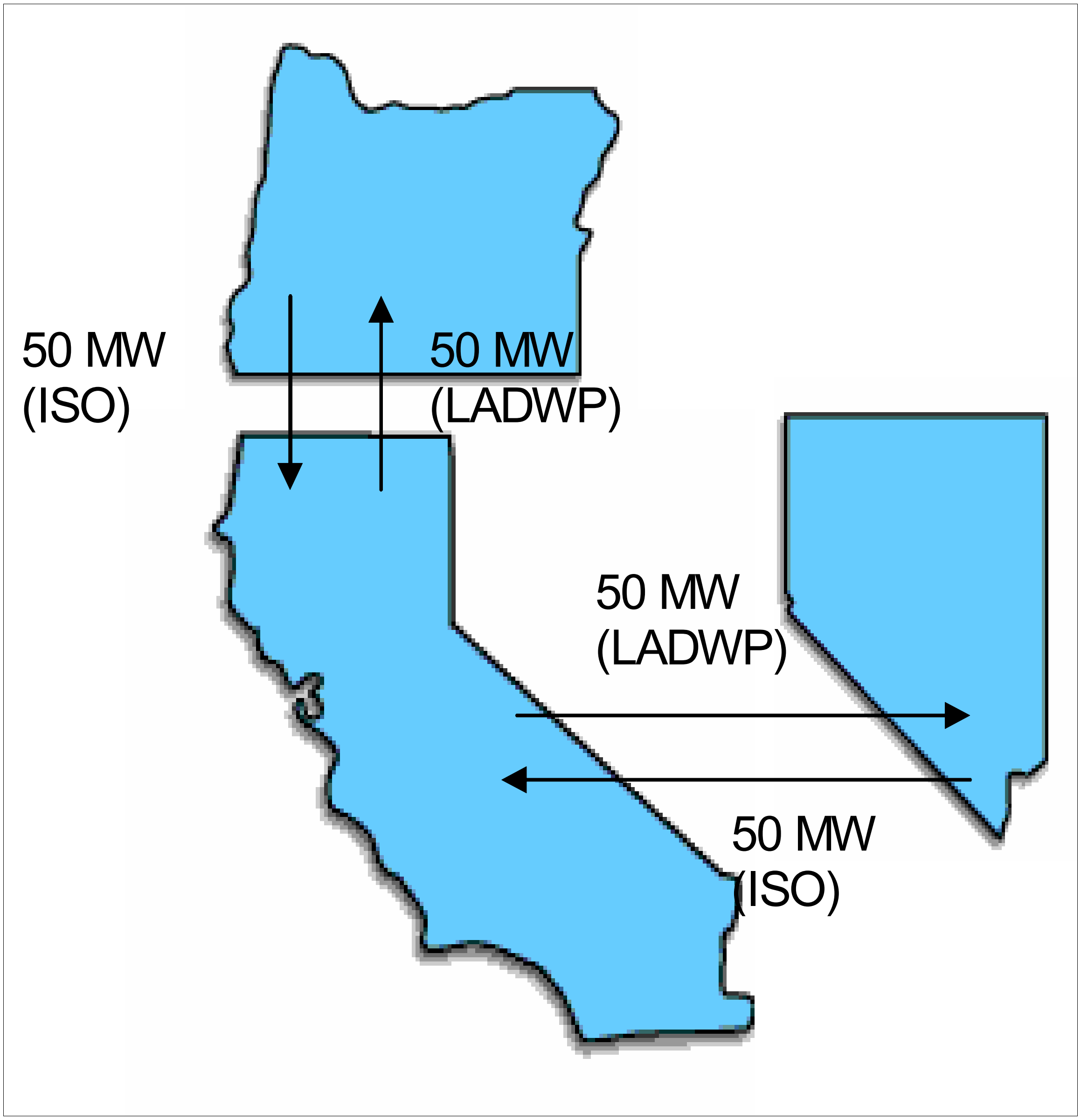


Figure 18 ***Example Death Star Transactions***

A key objective of this strategy was to receive fees from the ISO for relieving congestion, without having to provide any actual electricity at all. The ISO charges congestion fees to

[38]Schemes Death Star Workpapers, Exhibit SEATAC-426.

parties scheduling power in the congested direction, and pays those fees to parties scheduling power in the opposite direction. The holders of existing transmission contracts are exempt from congestion fees. Therefore, when a scheduling coordinator schedules power in the congested direction using the system of an ETC holder, and simultaneously schedules power in the opposite direction on the ISO's system, that scheduling coordinator will receive payments from the ISO, and will pay the ISO nothing.

Q. Have you been able to identify instances in which Death Stars actually occurred?

A. Some of the most valuable transmission contracts are held by the Los Angeles Department of Water and Power (LADWP). By comparing the information from LADWP's scheduling files and the ISO's scheduling records, it is possible to match up transactions with offsetting schedules that match this profile.

Q. Can you describe the steps involved?

A. Specifically, to find LADWP transactions that match the definition of a Death Star, I developed a mapping from LADWP's definitions of tie-points to the ISO's definition. That made it possible to match imports on one system to exports on another. I also developed a mapping of the ISO's abbreviations for scheduling coordinator to LADWP's codes for agents. This made it possible to identify when the same party was scheduling power on both systems. I eliminated schedules for ancillary services, because I wanted to match only those transactions that were eligible to receive payment in the event that a given line was congested.

I then searched the data for transactions that matched imports on the LADWP system with exports on the ISO system, by date, hour, scheduling coordinator, and tie-point. Such a match would meet the definition of a half Death Star (as described below). I also searched for the opposite case, i.e., for transactions that matched exports on the LADWP system with imports from the ISO system, by date, hour, scheduling coordinator, and tie-point. Such matches would also meet the definition of a half Death Star. Combining the results of these two searches by date, hour, and scheduling coordinator yields matches that meet the definition of a full Death Star.

Occassionally, as in the case with Enron, I included more than one scheduling coordinator at a time to see if they were acting together. It is clear from this analysis (as further described below) that Enron and Portland General Electric were working together on transactions that match the definition of a Death Star.

When I could not find accurate matches, I dropped information from the dataset, so there are undoubtedly more. To avoid double counting, I generally looked only at the hour-ahead market, although it is quite possible to have a Death Star in both the day-ahead and hour-ahead markets for the same date, time, and tie-point.

Q. What is the source of the LADWP scheduling records you used for this purpose?

A. I used files[39] called “All Schedules and Prices for 2000.csv” and “All Schedules and Prices for 1-1-2001 to 9-6-2001.csv” provided by LADWP to the California Senate Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. These files include detailed records of wholesale power transactions between LADWP and its counterparties involving use of LADWP transmission assets. Each record shows the date, counterparty, type of transaction (e.g., purchase, sale, wheeling), tie-points at which the

[39] LADWP Transaction Data, First Quarter 1997 through September 6, 2001, Exhibit SEATAC-424.

power entered and/or exited LADWP's system, various accounting information, hourly volumes, and, in some cases, hourly prices.

Q. What is the source of the ISO scheduling records you used for this purpose?

A. I used quarterly files[40] called "Imp_Exp_Sch_2000Q2.csv" through "Imp_Exp_Sch_2001Q4.csv," provided by the ISO to the California Senate Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. These files include detailed records of the schedules filed for imports and exports from the ISO system in the day-ahead, hour-ahead, and real-time markets. Each record shows the scheduling coordinator, date, hour, market type (i.e., day-ahead, hour-ahead, or real-time), designation of import or export, tie point, interchange ID, energy type (e.g., firm, non-firm, wheeling), external control area to/from which the power is scheduled, various accounting information, volume, adjustments to volume based on congestion model output, and prices.

Q. Are the schedules filed at the ISO and LADWP subject to the FERC confidentiality orders?

A. No. The California Senate Select Committee has released this information as part of their investigation into Enron's activities during the California crisis.

Q. Can you provide an example of such offsetting transactions?

A. Yes. Table 1 shows hourly transactions scheduled by Enron in the ISO Hour-Ahead market for April 15, 2000.[41] As we can see, Enron scheduled an import of 24 MW for one hour (the hour ending at 12:00 noon) at Mead. For each of the hours ending between 13:00 (1:00 PM) and midnight, they scheduled 24 MW to be imported at Palo Verde. For each of the

[40] CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.
[41] *Id.*

hours ending between noon and midnight, they also scheduled an export of 24 MW at Malin. In effect, they told the ISO they would bring 24 MW into California from Nevada and Arizona, ship it across the state, and export it at the California-Oregon border.

Table 1: ISO Side of Enron Death Star Transactions for 4/15/2000[42]

			Transactions (MW)		
Scheduling Coordinator	Date	Hour Ending	Import at Mead	Import at Palo Verde	Export at Malin
EPMI	4/15/2000	12	24	0	24
EPMI	4/15/2000	13	0	24	24
EPMI	4/15/2000	14	0	24	24
EPMI	4/15/2000	15	0	24	24
EPMI	4/15/2000	16	0	24	24
EPMI	4/15/2000	17	0	24	24
EPMI	4/15/2000	18	0	24	24
EPMI	4/15/2000	19	0	24	24
EPMI	4/15/2000	20	0	24	24
EPMI	4/15/2000	21	0	24	24
EPMI	4/15/2000	22	0	24	24
EPMI	4/15/2000	23	0	24	24
EPMI	4/15/2000	24	0	24	24

What they were not telling the ISO was that at the same time, using LADWP's transmission rights, they were scheduling this same transaction in reverse. Table 2 shows hourly transactions scheduled by Enron on the LADWP system.[43] As we can see, Enron scheduled a wheeling transaction for one hour (the hour ending at 12:00 noon) to import 24 MW at Malin, and to export 24 MW at Mead. For each of the hours ending between 13:00 and midnight, they scheduled a wheeling transaction to import 24 MW at Malin, and to export

[42]Schemes Death Star Workpapers, Exhibit SEATAC-426.
[43]LADWP Transaction Data, First Quarter 1997 through September 6, 2001, Exhibit SEATAC-424.

24 MW at Palo Verde. In effect, they told LA they would bring 24 MW into California from Oregon, ship it across the state, and export it to Nevada and Arizona. This transaction exactly offsets, hour by hour and MW by MW, the transaction they filed along the same paths at the ISO.

Table 2: LADWP Side of Enron Death Star Transactions for 4/15/2000[44]

			Transactions (MW)	
Agent	Date	Hour Ending	Wheel from Malin to Mead	Wheel from Malin to Palo Verde
EPM	4/15/2000	12	24	0
EPM	4/15/2000	13	0	24
EPM	4/15/2000	14	0	24
EPM	4/15/2000	15	0	24
EPM	4/15/2000	16	0	24
EPM	4/15/2000	17	0	24
EPM	4/15/2000	18	0	24
EPM	4/15/2000	19	0	24
EPM	4/15/2000	20	0	24
EPM	4/15/2000	21	0	24
EPM	4/15/2000	22	0	24
EPM	4/15/2000	23	0	24
EPM	4/15/2000	24	0	24

Q. If these transactions offset, did Enron make any money doing this?

A. Yes. Table 3 shows the congestion prices for the Hour Ahead market on the relevant ISO "Branch Groups."[45] The branch group called "COI_BG" includes Malin. At the time of these offsetting transactions, the ISO was effectively paying scheduling coordinators to schedule exports at Malin to relieve congestion. For example, during the first hour of the transactions outlined in Tables 1 and 2 above, Enron would have received $29 per MWk for scheduling an export at Malin on the ISO system. Table 3 also summarizes the total amount

[44]Schemes Death Star Workpapers, Exhibit SEATAC-426.

[45]Congestion prices for this date and hour are available at: http://www.caiso.com/marketops/OASIS/pubmkt2.html. At this URL, the user has the option of picking the appropriate date and hour, then select the link labeled "21: Hour Ahead Branch Group."

of revenue Enron should have received that day, according to these publicly-available sources. For the simple expedient of filing these schedules with the ISO and LADWP, we conclude that the ISO paid Enron $6,629.52.

Table 3: Revenues from Enron Death Star Transactions for 4/15/2000[46]

Scheduling Coordinator	Date	Hour Ending	Export at Malin	Congestion Price	Total Revenue
EPMI	4/15/2000	12	24	$ 29.00	$ 696.00
EPMI	4/15/2000	13	24	$ 31.00	$ 744.00
EPMI	4/15/2000	14	24	$ 28.99	$ 695.76
EPMI	4/15/2000	15	24	$ 20.00	$ 480.00
EPMI	4/15/2000	16	24	$ 20.00	$ 480.00
EPMI	4/15/2000	17	24	$ 20.00	$ 480.00
EPMI	4/15/2000	18	24	$ 22.38	$ 537.12
EPMI	4/15/2000	19	24	$ 20.00	$ 480.00
EPMI	4/15/2000	20	24	$ 20.00	$ 480.00
EPMI	4/15/2000	21	24	$ 21.92	$ 526.08
EPMI	4/15/2000	22	24	$ 19.00	$ 456.00
EPMI	4/15/2000	23	24	$ 23.94	$ 574.56
EPMI	4/15/2000	24	24	$ -	$ -
					$ 6,629.52

[46] Schemes Death Star Workpapers, Exhibit SEATAC-426.

Q. Did Enron have to deliver any electricity to earn this payment?

A. No.

Q. Didn't Enron have to show the ISO where this power was going?

A. Technically, Enron needed to show there was a source and a sink for the power being scheduled. Since the power was being imported and exported from the ISO system, Enron needed to explain where the power came from, and where it was going. For this step, for this set of transactions, Enron made use of its subsidiary, Portland General Electric (PGE). Table 4[47] shows the set of transactions undertaken by PGE on 4/15/2000, at the same times as those shown in Tables 1 through 3. In this table, we can see the set of schedules in the Northwest used to "cap" the Death Star transactions. Enron sells 24 MW to Washington Water Power (WWP) at COB. WWP sells 24 MW to PGE at COB. (This step appears to have been used to avoid affiliate trading restrictions between Enron and PGE.) PGE takes delivery on the power into its own system. WWP buys 24 MW from PGE on PGE's system. WWP sells 24 MW to Enron on PGE's system. Enron moves the power to John Day, for delivery back to Malin on the LA system.

[47] Portland General Electric Co. Affidavit, PA02-2-000, May 22, 2002, at 192, 196, Exhibit SEATAC-427.

Table 4

Date	Hour Ending	MW	Initial Control Area	Marketer	Marketer	Marketer	Sink-Source Control Area	Marketer	Marketer	Marketer	Marketer	Sink Control Area
4/15/2000	12	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	13	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	14	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	15	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	16	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	17	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	18	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	19	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	20	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	21	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	22	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	23	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
4/15/2000	24	24	CAISO	EPMI @COB	WWP @COB	PGE@ COB	PGE SYS	WWP @SYS	EPMI @SYS	PGE@ SYS	EPMI @JD	LADWP
Key: JD=John Day; PGE SYS=PGE Transmission System; COB=California Oregon Border												

Q. Was this difficult for Enron to execute?

A. Not at all. Despite the number of steps involved, this scheme, once invented, was apparently quite simple to execute. Each of these transactions can be completed in a minute or two by a competent trader. So for the investment of a few minutes' time, Enron was able to pocket hundreds, thousands, or tens of thousands of dollars.

An even more interesting set of transactions took place on 5/5/2000. On that day, PGE's affidavit shows[48] PGE doing a 45 MW "top half" transaction from hour-ending 12 through hour-ending 17. On that day, PGE also filed an LADWP schedule to wheel power from COB to Mead -- 45 MW from hour 12 through hour 16. For hour ending 17, Enron filed a single additional hour for the same path, and the same number of megawatts. On the same day, for hours 12 through 17, Enron filed exactly offsetting ISO schedules -- import 45 MW at Mead, export 45 MW at COB. This set of transactions speaks volumes about how tightly their trading desks were integrated. We can envision no way that this set of transactions could have taken place without close coordination between the two companies and the full knowledge of the implications of the transactions being known to PGE staff and management.

Table 5 presents several more examples of Enron's Death Star transactions during the summer of 2000.

[48] *Id.* at 195.

Table 5: Example Enron "Death Star" Events, Summer 2000[49]

			CAISO			LADWP		
Date	Time	MW	Party	From	To	Party	From	To
6/6/2000	14-15	40	EPMI	COB	Mead	EPMI	Mead	COB
6/13/2000	17-20	45	EPMI	COB	Mead	EPMI	Mead	COB
7/14/2000	15-19	35	EPMI	COB	Palo Verde	EPMI	Palo Verde	COB
7/15/2000	16-17	35	EPMI	COB	Palo Verde	EPMI	Palo Verde	COB
7/17/2000	16-21	45	EPMI	COB	Palo Verde	EPMI	Palo Verde	COB
8/2/2000	11,13-20	25	EPMI	NOB	Mead	EPMI	Mead	NOB
8/11/2000	12-17	45	EPMI	COB	Mead	EPMI	Mead	COB
8/14/2000	13-19	45	EPMI	COB	Mead	EPMI	Mead	COB
8/15/2000	12-15	45	EPMI	COB	Mead	EPMI	Mead	COB
8/17/2000	11-18	45	EPMI	COB	Mead	EPMI	Mead	COB
8/18/2000	11-18	45	EPMI	COB	Mead	EPMI	Mead	COB
8/19/2000	14	45	EPMI	COB	Mead	EPMI	Mead	COB
8/21/2000	12-19	45	EPMI	COB	Mead	EPMI	Mead	COB
8/22/2000	13-19	45	EPMI	COB	Mead	EPMI	Mead	COB
9/7/2000	17-20	45	EPMI	COB	Mead	EPMI	Mead	COB

Q. Did Enron have a system for keeping track of its Death Star transactions?

A. Apparently so. The ISO requires that the scheduling coordinator provide an "Interchange ID" as part of its methods for identifying schedules. Enron often used suggestive entries for interchange ID values. Some are obscure (e.g., "CISO_EPMI_5001"), but others are far more transparent. In the example provided above (4/15/2000), the interchange ID's used include CISO_EPMI_FORNEY, and EPMI_CISO_DANNY. Forney is almost certainly Enron trader John Forney, inventor of Forney's Perpetual Loop. Mr. Forney appears in another transaction under the name "FORNDOG." Other pairs of transactions include portions of interchange ID values such as "KING" and "QUEEN," "BASS" and "TROUT," "VW" and "JETTA," "BERT" and "ERNIE," and the self-explanatory "DEATH" and "STAR."

[49]Schemes Death Star Work Papers, Exhibit SEATAC-426. .

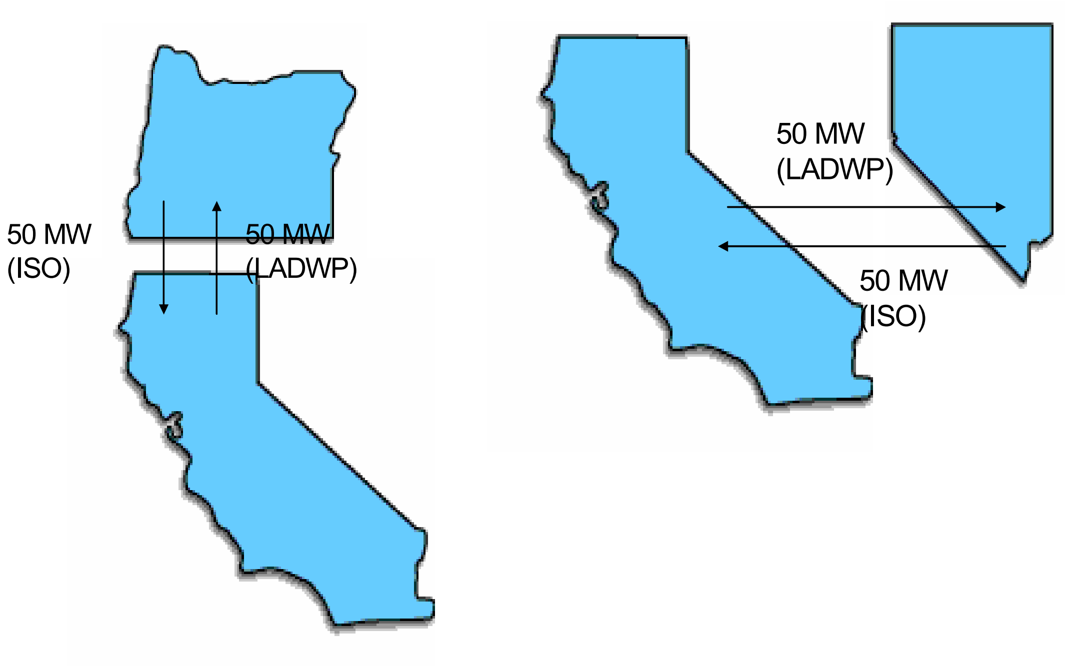
Q. Are all of these steps necessary to earn congestion revenues through offsetting schedules?

A. No. I said earlier that the term Death Star was applied to both a specific scheme (as described above), and to a family of schemes. As we have reviewed the ISO and LA data, it is clear that a "half Death Star" will accomplish much the same goal.

Q. Please describe what you mean by a "half Death Star."

A. In a half Death Star, a scheduling coordinator files a schedule with the ISO to import power at a given tie point, and files an offsetting schedule on LADWP's system to export power at the same tie point (or vice versa). Figure 2 shows how two different versions of a half Death Star can work.

Figure 2: Example Half Death Star Transactions[50]



Q. Did you find examples of this type of transaction as well?

A. Yes. For example, on June 17, 2000, during the hour ending at 5:00 PM, Enron scheduled an export of 50 MW at Malin on the ISO system.[51] For the same hour, PGE scheduled an import of 50MW at Malin on the LA system.[52]

In addition to the example above, it is not even necessary for the amount of power scheduled in each direction to match. For example, if the scheduling coordinator schedules 50 MW in one direction and 30 MW in the other, this can be considered a 30 MW half

[50] Schemes Death Star Workpapers, Exhibit SEATAC-426.

[51] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[52] *Id.*

Death Star.

Q. Is this the only example of a half Death Star you found?

A. No, actually we found tens of thousands, looking at the period between January 1, 2000 and September 6, 2001.[53] Table 6 provides the number of matching transactions we detected just looking at some of the parties named in various FERC investigations. The number of transactions given here represents the hour-ahead schedules at a given tie point, date, and hour matching the description of a half Death Star provided above. Given that the universe of Death Stars are so large, we could have taken a much longer list of scheduling coordinators than these. This list was based on the major generators and several other major market participants.

Table 6: Half Death Star Transactions for Selected Scheduling Coordinators[54]

Party	In	Out
AEP	1025	5
Coral	218	826
Duke	1059	194
Dynegy	16	0
Enron	6169	3369
Idaho Power	491	6930
Reliant	24	1291
Powerex	5592	12269
Mirant	634	323
Williams	254	8306

Q. Can you provide an example of how AEP filed schedules that match the description of a half Death Star?

[53] *Id.*
[54] Schemes Death Star Workpapers, Exhibit SEATAC-426.

A. Yes. We found over 1000 tie-point-hours of such transactions.[55] On July 21, 2000, AEP scheduled an import of 50 MW at Palo Verde on the ISO system for the hour ending at 7:00 AM.[56] For the same date and time, they scheduled an export of 25 MW on the LADWP system.[57] This pair of transactions meets the definition of a 25 MW half Death Star.

Q. Can you provide an example of how Coral filed schedules that match the description of a half Death Star?

A. Yes. We found over 1000 tie-point-hours of such transactions.[58] On April 27, 2000, Coral scheduled an import of 50 MW at Palo Verde on the ISO system for the hour ending at 16:00.[59] For the same date and time, they scheduled an export of 50 MW on the LADWP system.[60] This pair of transactions meets the definition of a 50 MW half Death Star.

Q. Can you provide an example of how Duke filed schedules that match the description of a half Death Star?

A. Yes. We found over 1000 tie-point-hours of such transactions.[61] On July 5, 2000, Duke

[55]LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[56]CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[57]LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

[58]LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[59]CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[60]LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

[61]LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2001, Exhibit SEATAC-424.

scheduled an import of 150 MW at Palo Verde on the ISO system for the hour ending at 9:00 AM.[62] For the same date and time, they scheduled an export of 50 MW on the LADWP system.[63] This pair of transactions meets the definition of a 50 MW half Death Star.

Q. Can you provide an example of how Dynegy filed schedules that match the description of a half Death Star?

A. Yes. We found 16 tie-point-hours of such transactions.[64] On July 12, 2000, Dynegy scheduled an import of 25 MW at Palo Verde on the ISO system for the hour ending at 11:00 AM.[65] For the same date and time, they scheduled an export of 25 MW on the LADWP system.[66] This pair of transactions meets the definition of a 25 MW half Death Star.

Q. Can you provide an example of how Idaho Power filed schedules that match the description of a half Death Star?

A. Yes. We found over 7000 tie-point-hours of such transactions.[67] On March 12, 2001, Idaho Power scheduled an export of 100 MW at Malin on the ISO system for the hour ending at 7:00.[68] For the same date and time, they scheduled an import of 70 MW on the

[62]CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[63]LADWP All Schedules and Prices 2000 .csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

[64]LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[65]CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[66]LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

[67]LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-424.

[68]CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

LADWP system.[69] This pair of transactions meets the definition of a 70 MW half Death Star.

Q. Can you provide an example of how Powerex filed schedules that match the description of a half Death Star?

A. Yes. We found over 17000 tie-point-hours of such transactions.[70] On May 1, 2001, Powerex filed an export of 50 MW at Malin on the ISO system for the hour ending at 15:00.[71] For the same date and time, they scheduled an import of 50 MW on the LADWP system.[72] This pair of transactions meets the definition of a 50 MW half Death Star.

Q. Can you provide an example of how Reliant filed schedules that match the description of a half Death Star?

A. Yes. We found over 1000 tie-point-hours of such transactions.[73] On June 29, 2000, Reliant scheduled an export of 114 MW at Mead on the ISO system for the hour ending at 19:00.[74] For the same date and time, they scheduled an import of 54 MW on the LADWP system.[75] This pair of transactions meets the definition of a 54 MW half Death Star.

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[69] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

[70] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[71] CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[72] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

[73] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[74] CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[75] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

Q. Can you provide an example of how Mirant filed schedules that match the description of a half Death Star?

A. Yes. We found over 900 tie-point-hours of such transactions.[76] On August 17, 2000, Mirant scheduled an export of 25 MW at Palo Verde on the ISO system for the hour ending at 14:00.[77] For the same date and time, they scheduled an import of 25 MW on the LADWP system.[78] This pair of transactions meets the definition of a 25 MW half Death Star.

Q. Can you provide an example of how Williams filed schedules that match the description of a half Death Star?

A. Yes. We found over 8000 tie-point-hours of such transactions.[79] On January 8, 2001, Williams scheduled an export of 100 MW at Mead on the ISO system for the hour ending at 22:00.[80] For the same date and time, they scheduled an import of 75 MW on the LADWP system.[81] This pair of transactions meets the definition of a 75 MW half Death Star.

Q. Are these schemes inter-regional?

A. Yes. The basic premise of these schemes is to take advantage of the ISO's congestion management methodology by filing circular schedules that pass through the ISO to

[76] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[77] CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[78] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

[79] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[80] CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[81] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

another control area.[82] In practice, thousands of these schedules involve Death Stars that rotate "power" through the Pacific Northwest.[83]

Q. Has the ISO undertaken its own investigation into detecting Death Stars?

A. Yes. In December, 2002, the ISO released a report, dated 10/4/2002, from its Market Analysis Group.[84] This report included analysis of several of the Enron schemes, including Death Stars. In January, the ISO updated their calculations. This report was posted on the ISO Web site. In addition, it was provided to the California Senate Select Committee mentioned above.

Q. Have you reviewed the report provided by the ISO describing its efforts to detect Death Stars?

A. I have. The methods described in the report[85] may detect certain types of Death Star transactions, but will almost certainly miss a great many more. In particular, the report states that:

> The potential frequency and financial gains from circular schedules were analyzed by identifying import/export schedules (of equal quantities) by the same SC that generated congestion revenues from counterflows on interties and/or internal paths within the ISO. It should be noted that this approach may underestimate circular schedules since the analysis only

[82] Traders' Strategies in the California Wholesale Power Markets/ ISO Sanctions, Christian Yoder and Stephen Hall, December 6, 2000, Exhibit SEATAC-8.

[83] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424; CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[84] Analysis of Trading and Scheduling Strategies Described in Enron Memos, California ISO, Department of Market Analysis, 10/4/2002, Exhibit SEATAC-67.

[85] *Id.*

> includes import/export schedules that can be matched because they are of (approximately) equal quantities by the same SC.[86]

The report correctly identifies two deficiencies in the ISO's methodology. First, the ISO method matches on MW quantities, so any party attempting to hide its Death Star transactions by combining them with other transactions will be missed. Second, the ISO method requires matching schedules to be filed by the same scheduling coordinator. While this is usually a good assumption, Enron and PGE were separate scheduling coordinators, and sometimes filed schedules that offset one another. To the extent this excerpt from the report is accurate, however, the more important deficiency is that the ISO method completely ignores the case of half Death Stars, requiring that both an import and an export appear in the ISO's records.

Q. Even though they may have missed some, did the ISO find many potential Death Star transactions?

A. Yes. The following table[87] is reproduced from the ISO report; this table provides a summary of the ISO's work on Death Star transactions.

[86] *Id.* at 8.
[87] *Id.* at 11.

Table 2. Total Congestion Revenues from Counterflows Created by Import/Export Schedules (Matched by MW Amount) by SC

SC_ID	Name	1998	1999	2000	2001	2002	Total
CRLP	Coral Power, LLC			$1,366,933	$1,279,190	$1,229,360	$3,875,484
EPMI	ENRON Power Marketing Inc		$84,148	$1,039,960	$1,673,440		$2,797,548
SETC	Sempra Energy Trading		$87,746	$1,190,556	$237,161	$133,960	$1,649,422
PWRX	British Columbia Power Exchange			$44,779	$329,732	$710,162	$1,084,673
WESC	Williams Energy Services		$856,597	$43,907	$15,047	$50,731	$966,283
CAL1	Cargill Alliant, LLC			$1,025	$14,289	$877,964	$893,278
APX1	Automated Power Exchange, Inc				$679,500	$2,662	$682,162
IPC1	Idaho Power Company			$617,116	$51,949		$669,065
PAC1	PacificCorp	$413,325	$20,558		$65,228	$25,757	$524,869
SCEM	Mirant			$54,436	$146,243	$295,658	$496,337
DETM	Duke Energy Trading	$64,018	$8,294	$95,340	$26,465	$21,535	$215,651
ANHM	City of Anaheim			$136,725	$13,832		$150,557
CALP	Calpine Energy Services				$4,376	$127,984	$132,360
APS1	Arizona Public Service Company		$90,895	$36,101			$126,996
MID1	Modesto Irrigation District		$34,398	$24,358	$20,847	$326	$79,929
MSCG	Morgan Stanley Capital Group				$36,614		$36,614
AEPS	American Electric Power Service					$19,481	$19,481
APX4	Automated Power Exchange				$6,675	$12,052	$18,727
AQPC	Aquila Power Corporation			$6,288			$6,288
PSE1	Puget Sound Energy			$1,815			$1,815
RVSD	City of Riverside		$1,501	$0			$1,501
	Grand Total	$477,343	$1,184,151	$4,659,341	$4,600,587	$3,507,633	$14,429,055

Note: Includes all import/export combinations by the same SC (matched by MW amount) that earned net congestion revenues from counterflows on interties and internal ISO paths. The ISO does not have sufficient information to determine if these schedules represent actual physical sources and sinks that mitigated congestion, or are the type of "circular" schedule with not physical source and sink, such as the Death Star scheme described in the Enron memos.

Q. Do you have examples of transactions that the ISO may have missed?

A. Yes. The example I gave above for June 17 at the hour ending at 17:00 is not identified in the ISO data. This event is particularly interesting, since the congestion price at Malin for that hour was $685.09. The 50 MW half Death Star filed by Enron and PGE provided them with over $34,000 in revenue in a single hour that day.

Another example of a half Death Star not found in the ISO report is found on 10/21/2000 in the hours ending at 19:00 and 20:00. During those two hours, Enron scheduled an export of 50 MW at Palo Verde, while the Palo Verde branch group was congested in the import direction.[88] At the same time, Enron scheduled an import of 50 MW at Palo Verde on the LADWP system.[89] The net effect to relieving an true congestion was, of course, zero, but the ISO had to pay Enron over $1,500 just the same.[90]

The point here is that the ISO method, if we understand it correctly, is bound to miss almost all half Death Stars, because it is not designed to catch them. The ISO's method, according to the description found in the report,[91] will also miss transactions in which the megawatt volumes do not match. By missing what appears to be the majority of all Death Star and half Death Star transactions, we can safely conclude that their estimates of the dollar impact are too low as well.

Q. Can you estimate the dollar impact of the Death Star and half Death Star schemes?

A. No.

Q. Why not?

A. I don't have the data necessary to prepare an accurate estimate.

Q. Was such data requested from the ISO?

A. The ISO simply replied that these schemes were irrelevant to the question of refunds. The request and complete ISO response to our request was as follows:

TAC/CAISO 2.2

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[88] CAISO Transaction Data, Third Quarter 1998 through Third Quarter 2002, Exhibit SEATAC-425.

[89] LADWP All Schedules and Prices 2000.csv and All Schedules & Prices for 1-1-2001 to 9-6-2001.csv, Exhibit SEATAC-424.

[90] Congestion prices for this date and hour are available at: http://www.caiso.com/marketops/OASIS/pubmkt2.html. At this URL, the user has the option of picking the appropriate date and hour. Then select the link labeled "21: Hour Ahead Branch Group."

[91] Analysis of Trading and Scheduling Strategies Described in Enron Memos, California ISO, Department of Market Analysis, 10/4/2002, Exhibit SEATAC-428.

Please refer to the document entitled *Analysis of Trading and Scheduling Strategies Described in Enron Memos*, a report by California ISO Department of Market Analysis, dated October 4, 2002, available on the ISO's website at www.caiso.com (hereinafter "CAISO Report").

(a) Please provide any information, studies, or analyses that the CAISO has performed or that it has in its possession concerning congestion payments to the entities listed in tables 2, 6, 7, 9, 11, and 12 of the CAISO Report.

(b) Please provide any information, studies, or analyses that the CAISO has performed or that it has in its possession concerning overscheduling of power by entities listed in the CAISO Report, and the associated economic impacts.

(c) Please provide all studies the CAISO has performed regarding manipulation or potential manipulation of markets in the northwestern United States and/or involving use of the AC Intertie by the entities listed in tables 2, 6, 7, 9, 11, and 12 of the CAISO Report.

(d) Please provide all workpapers used in creating the CAISO Report.

Response:

The ISO objects to the entirety of question 2.2 because it seeks information that is not relevant to the claim or defense of any party, is not reasonably calculated to lead to the discovery of admissible evidence, and seeks data regarding activities/parties that are not relevant to the subject matter of this proceeding.

The October 4 Report deals with conditions in and analysis of spot markets operated by the California ISO. Therefore, none of the information requested is relevant to claims "concerning potential refunds for spot market *bilateral sales transactions* in the Pacific Northwest for the period January 1, 2000 through June 20, 2001," December 19 Discovery Order at P 1 (emphasis added), and is not likely to lead to the discovery of relevant information.

Notwithstanding this objection, the ISO notes that some information responsive to this question has been provided by the ISO in Docket Nos. EL02-113 (on December 16, 2002 and February 4, 2003), EL02-114 (on November 4, 2002 and January 30, 2003), and EL02-115 (on November 19, 2002) in response to discovery posed on the ISO by the Commission Staff in each case.

Respondent: Eric Hildebrandt
Manager, Market Investigation

Date: February 6, 2003[92]

Fat Boy

Q. Can you describe Fat Boy?

A. Yes. A Fat Boy was a schedule to the California ISO for a non-existent or exaggerated load.[93]

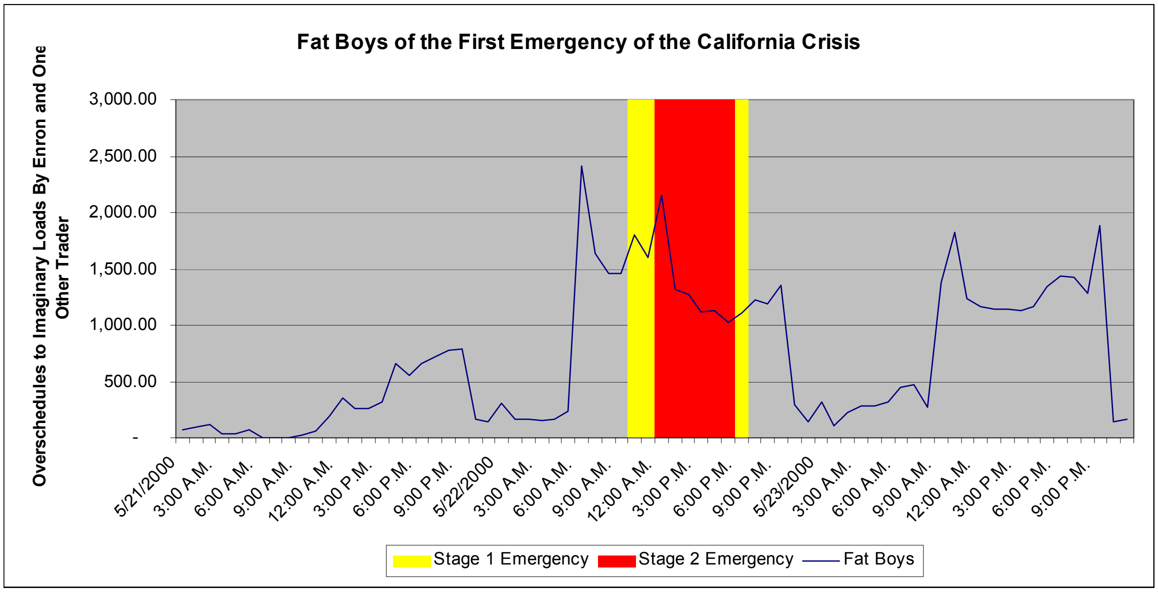
Q. Are Fat Boys of sufficient size to affect operations at the ISO and the PX?

A. Yes. The scale of Fat Boys – schedules to non-existent loads was enormous over the period. The following chart shows the sum of three traders Fat Boy schedules.

[92]Objections of the California Independent System Operator Corporation to City of Tacoma and Port of Seattle's Second Set of Data Requests - TAC-ISO-2.2. Docket No. EL01-10-005, February 6, 2003, Exhibit SEATAC-431.

[93]Traders' Strategies in the California Wholesale Power Markets/ ISO Sanctions, Christian Yoder and Stephen Hall, December 6, 2000, Exhibit SEATAC-432.

Figure 3[94]



Clearly, total Fat Boys on May 22, 2000 were a significant portion of the entire California energy portfolio.[95] The open question is why Enron and the other traders were willing to take the enormous risk that the crisis would not take place and they would be paid zero for this vast block of energy. The ISO has stated that it treats schedules to imaginary loads as the same as any other schedule. There is a major difference, however. Other schedules are penalized if they are not served with real energy. Fat Boys, by definition, will never fail to serve their load – simply because there is no load corresponding to these schedules. Thus not only is the payment for

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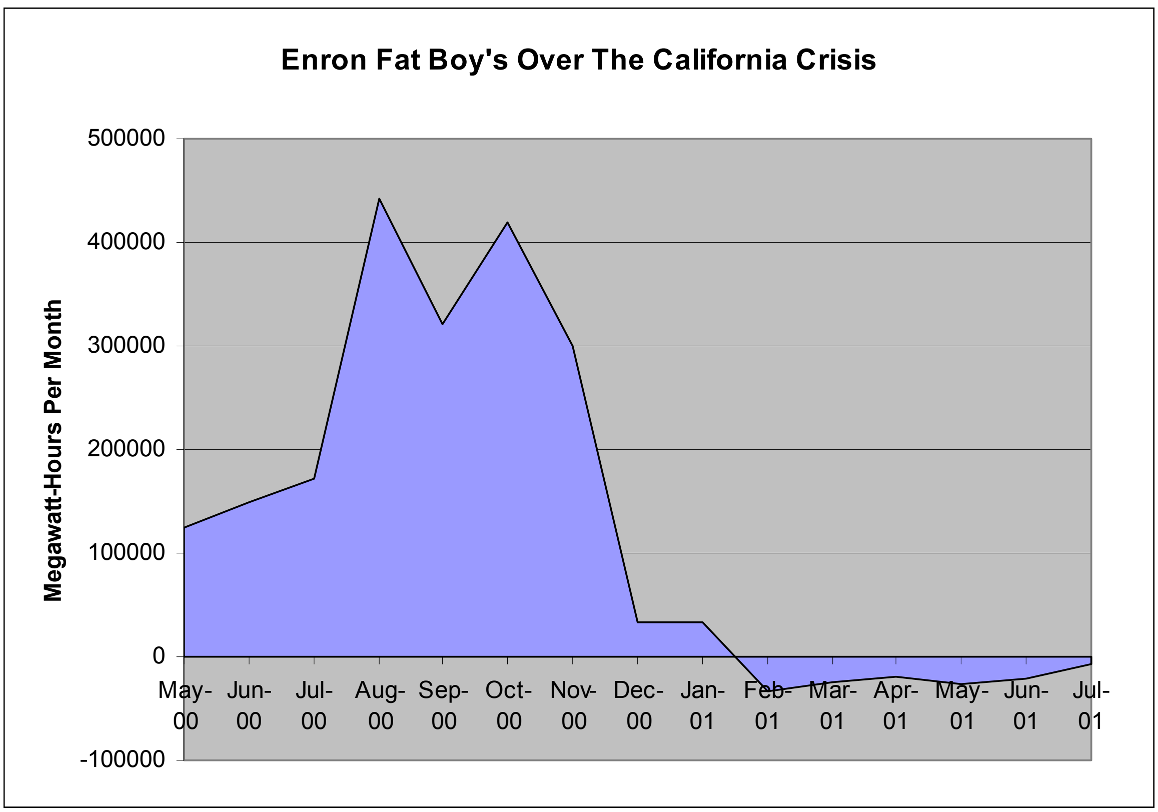
[94]*Id.*

[95]Schemes Fat Boys Workpapers, Exhibit SEATAC-429 (contains protected materials). Publicly available source data and confidential ISO source data obtained from California State Senate Select Committee to Investigate Prior Manipulation of the Wholesale Energy Market Source data downloaded from : http://www.ucei.berkeley.edu/ucei/datamine/datamine.htm.

this energy non-firm, the schedule itself is effectively non-firm since there is no penalty for non-delivery.

Fat Boys placed enormous pressure on the complex California system. They pulled energy from the PX and the ISO markets and delivered the energy to the "back door" in a way where its delivery was uncertain. Enron's commitment to Fat Boy was enormous– over $200 million placed at risk on the gamble that the power scheduled to imaginary loads would be paid for.[96]

Figure 4[97]

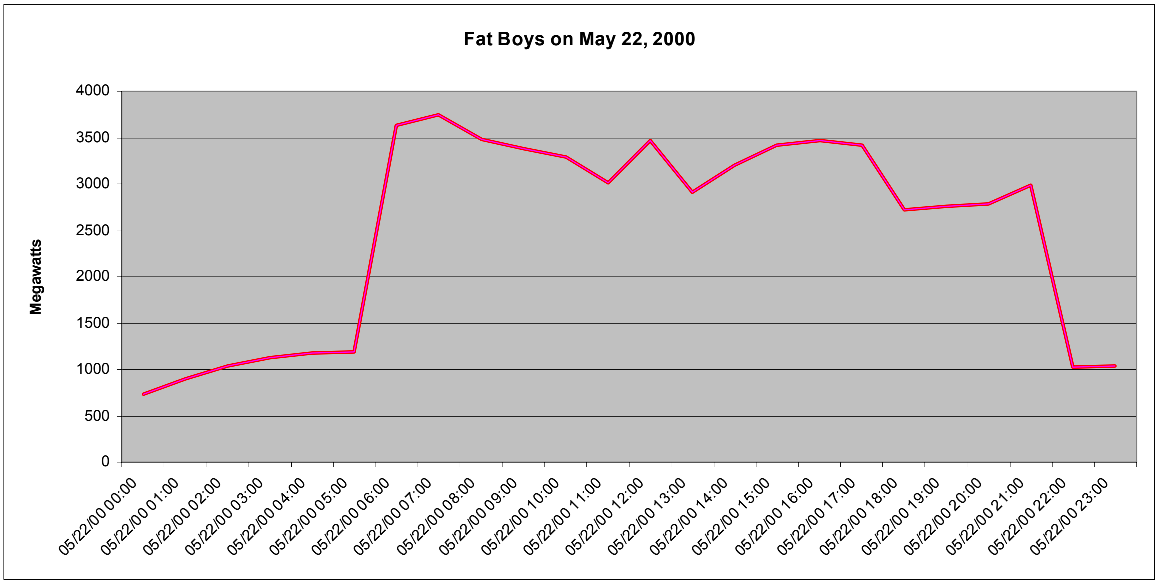


Q. Were Fat Boys a significant issue in the operations of the Power Exchange and the ISO?

[96]Id.
[97]Id.

A. Yes. The scheduling of energy to non-existent loads was common. The following chart shows Fat Boys for the first declared emergency of the California crisis.

Figure 5[98]

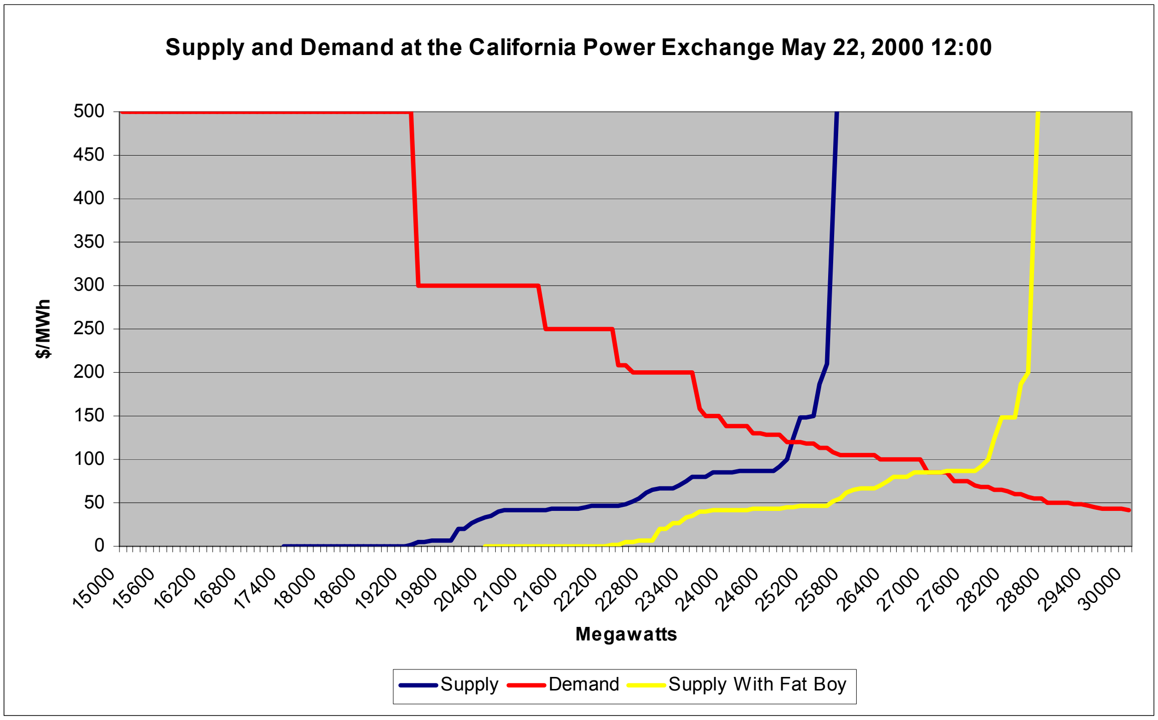


Q. Why was the energy dedicated to Fat Boy effectively withheld from the California Power Exchange?

A. A Fat Boy removed energy from the supplies offered to the Power Exchange. In effect, the Fat Boy moved the supply curve at the power exchange to the left. The following chart shows supply and demand at the Power Exchange on May 22, 2000 at 12:00 P.M. The blue line reflected the actual market. A large block of energy was scheduled to non-existent loads (more precisely, schedules much larger than the likely load) at the ISO. If this energy had been placed in the market as the design of the California system intended, the supply curve would have shifted to the right.

Figure 6[99]

[98] *Id.*
[99] *Id.*



Q. Do we know what price Enron and others would have bid into the PX?

A. No. This analysis assumes that they would have moved the entire curve right. For this hour, any bid at less than $85/MWh would have been sufficient to reduce the PX price.

Q. What was the impact of shifting the supply curve 3,470 megawatts to the left at this hour?

A. The shift raised the price where the demand and supply curves crossed by $35 – the difference between the actual PX unconstrained price of $120 and the $85 that would have occurred if the Fat Boys would have been included in the energy supply.

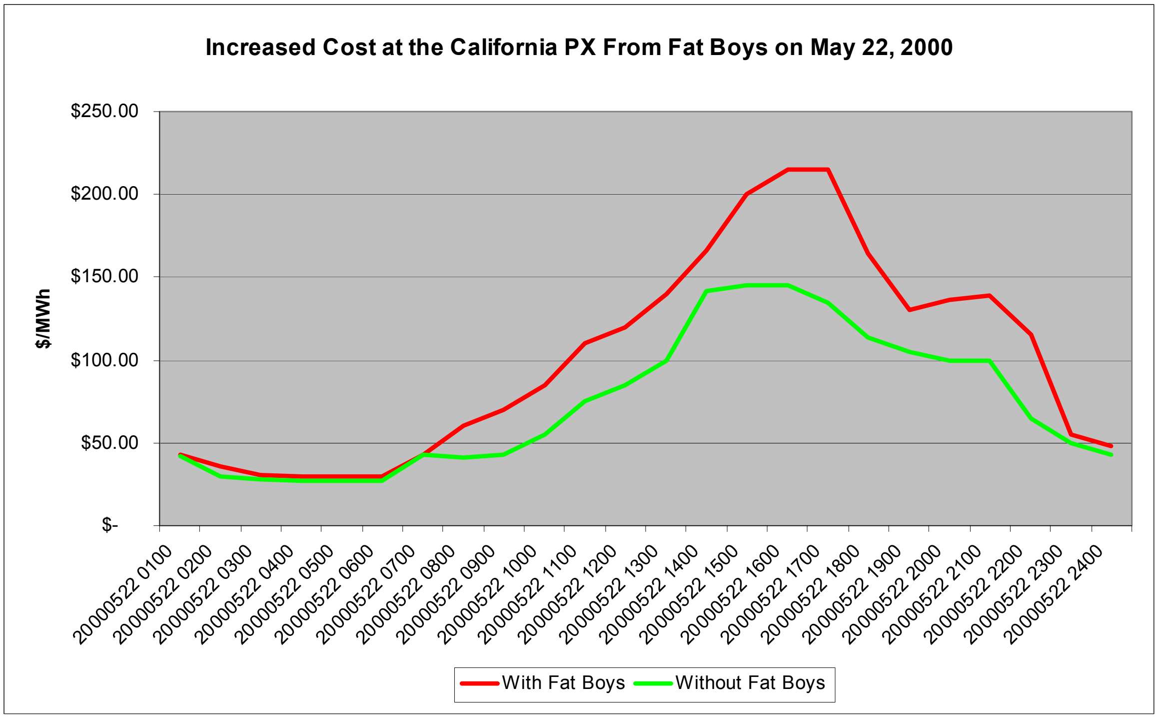
Q. Have you conducted this analysis for every hour of the California crisis?

A. No. Data from the ISO was only provided on Monday, February 24.

Q. Given the data we currently have, what impact did these Fat Boys have on consumers on May 22, 2000?

A. Prices at the California Power Exchange were $38.46/MWh higher on-peak and $3.71/MWh off-peak. The following chart shows the impact by hour:

Figure 7[100]



[100]Id.