SNO-63

PUBLIC DOCUMENT – PAGES 95-97, 99-100, 102-103, 115 CONTAIN PRIVILEGED INFORMATION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Nevada Power Company and Sierra Pacific Power Company v. Enron Power Marketing, Inc., El Paso Merchant Energy, American Electric Power Services Corp.	**Docket Nos. EL02-28-000, EL02-33-000 and EL02-38-000**
Nevada Power Company v. Morgan Stanley Capital Group, Calpine Energy Services, Reliant Energy Services, Mirant Americas Energy Marketing, L.P., BP Energy Company, Allegheny Energy Supply Company, L.L.C.	**Docket Nos. EL02-29-000, EL02-30-000, EL02-32-000, EL02-34-000 and EL02-39-000**
Southern California Water Company v. Mirant Americas Energy Marketing, L.P.	**Docket No. EL02-43-000**
Public Utility District No. 1 Of Snohomish County, Washington, v. Morgan Stanley Capital Group, Inc.,	**Docket No. EL02-56-000**

REBUTTAL TESTIMONY OF ROBERT MCCULLOUGH ON BEHALF OF PUBLIC UTILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY, WASHINGTON

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY.

A. My testimony rebuts the testimony of Dr. Kalt, representing El Paso Gas, and Drs. Hogan and Harvey, representing Morgan Stanley. Specifically, I analyze the theoretical models and underlying assumptions upon which these witnesses rely in their arguments.

Q. PLEASE SUMMARIZE THE STRUCTURE OF YOUR REBUTTAL IN THIS CASE.

A. My rebuttal is broken into six sections:

1. Background
   a. Summary of Positions on the Issues
   b. Key Facts in the Case
   c. Historical Context of the 2001-2000 California Electricity Crisis.
2. A Survey of Planning Criteria showing the relationship of the events of the California crisis to traditional planning methods
   a. Actual Planning Goals throughout the WSCC
   b. WSCC 2000 results compared to standard planning goals
   c. Presence of other problems such as major transmission outages
   d. Hydro reliability standards
3. A review of Dr. Hogan's description of the California crisis identifying the numerous errors and omissions in his testimony
   a. Hydro calculations
   b. RTC
   c. Generation of the "Big Five" during Stage 1, Stage 2, And Stage 3

Emergencies.

4. A review of the actual, as opposed to the theoretical, forward markets and their relationship to spot markets
5. A discussion of the facts available to market participants during the crisis, showing that forward prices continued to climb even after plant announcements were made
6. A discussion of respondents' attempt to specify the observed relationship between spot and forward markets

SECTION 1: BACKGROUND

Q. PLEASE CONTRAST THE RESPONDENT'S POSITIONS FROM YOURS.

A. Drs. Harvey, Hogan and Kalt present a precarious, theoretical picture of the May 22, 2000 to July 3, 2001 crisis. They argue that a sudden sharp shortage of electric capacity and energy, as well as a shortage of natural gas, created a temporary price spike in spot markets. Coincidentally, they also believe that long term markets experienced a similar spike in prices due to a similar sharp shortage in long term supplies. In making these arguments, they must walk a perilous theoretical tightrope. On one hand, they must defend the forward prices as just and reasonable results of an efficient forward market. The fact that forward prices tagged along closely behind the unjust and unreasonable spot prices is a difficult challenge to their position. On the other hand, they are forced to argue that a surplus of capacity over requirements that averaged 20% during this period must have been evidence of shortage. Moreover, the sharp reduction in long term prices that directly paralleled the reduction in spot prices must have reflected market forces well understood by market participants. That spot prices should make dramatic moves unpredicted by forward markets, while supposedly reflecting market fundamentals easily seen in advance by market participants, defies common sense. That forward markets should make dramatic changes supposedly in response to long-term market fundamentals that remained essentially unchanged defies common sense.

Our position is much simpler. It also has the merit of fitting the available data vastly better. The crisis in California reflected a market failure based on generation withholding and market manipulation. Consequently, as FERC has already found, the spot prices for this period were unjust and unreasonable.[1] The spot crisis spilled over into the forward markets, with devastating effect. The forward markets were neither efficient not robust, and indeed were largely destroyed during the period in question. The WSCC entered the crisis with three forward markets, NYMEX, the PX Block Forwards Market (BFM), and the over the counter bilateral market. Only one of these survived the crisis in any form, and, as the experience of Snohomish PUD demonstrates, the bilateral market was paper

[1]There has been some debate as to whether this term is a legal judgment. The prices in spot markets during this period were unjust because they were the result of manipulation. FERC's decision to enact a "must offer" rule and its investigation into the various manipulation schemes clearly indicate that the market was unjust. The market was unreasonable because it caused the appearance of scarcity when the state and the region were well within traditional planning guidelines for reliability.

thin.

We have been unable to identify even a single entity that correctly forecasted the crisis. While there were many predictions of potential short-term peaks in spot prices, as occurred in the summers of 1998 and 1999, neither the forward markets nor any of the market participants predicted either the onset of the crisis or its departure.

Q. WHAT ARE THE MAJOR FACTS IN THIS CASE?

A. The facts in this case are straightforward and consistent with previous FERC decisions and reports:

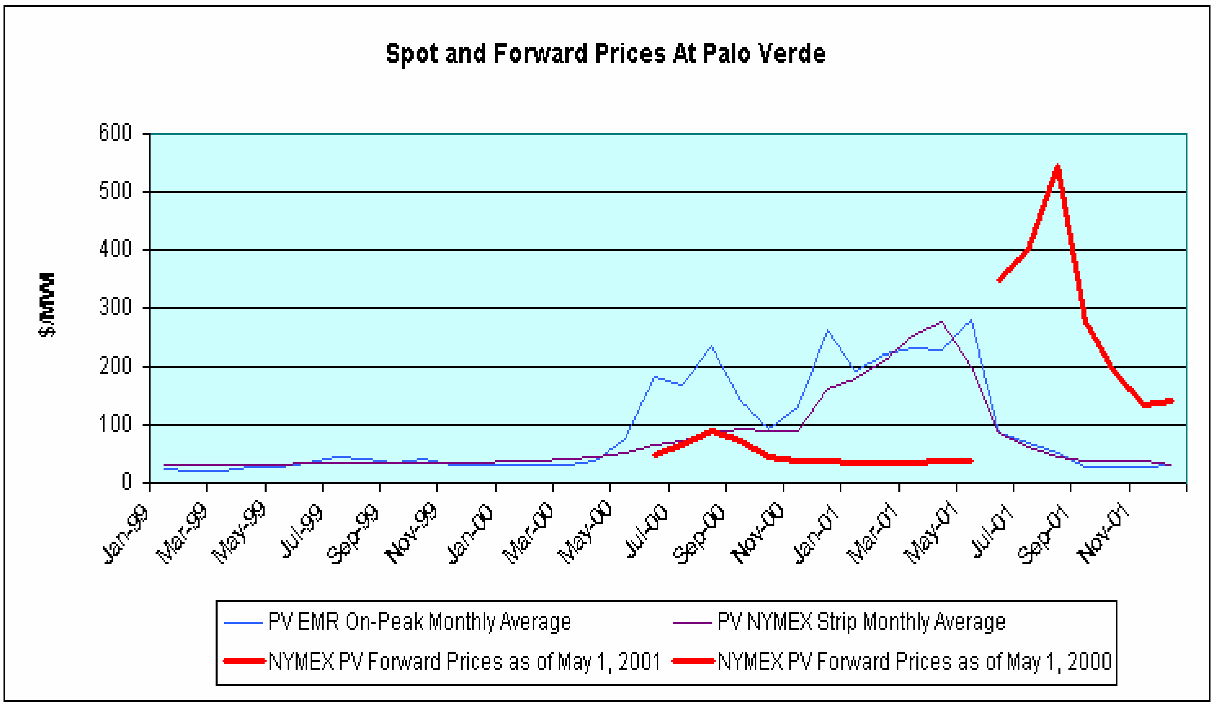
In the winter and early spring of 2000, no one expected the massive crisis in California that began on May 22, 2000. We now know that even Enron's forecasts for the summer of 2000 showed no estimates of the crisis and its emergencies. The forward markets reflected values that were consistent with the known fundamentals.

California peak loads were lower than in previous years and the worst reserve margin for the entire crisis was 13.5% – well within the standard planning criteria for safe operation of the system. Hydro operations were roughly average and significantly better than the droughts of 2001 and 1994.

The incentives and structures of the California market rewarded market dysfunction. We know that plants never reached their capacity limits, even in the midst of Stage 1, Stage 2, and Stage 3 emergencies. We also know that a variety of market manipulations were spawned to take advantage of California structural weaknesses. FERC has already ruled that the prices caused by these manipulations are unjust and unreasonable. The efforts of the respondents to rewrite history are interesting, but ultimately irrelevant to the case at hand.

Once the crisis began, forward prices tracked upwards with spot prices on a month by month basis. This brings into question the theoretical belief of Drs. Kalt and Hogan that long term contract prices were driven only by long term fundamentals. Simply, we know that the long term fundamentals were not changing on a monthly basis. To the degree they did, they were improving, not deteriorating. A detailed analysis of the forward price series indicates that these prices continued to rise even after plant construction announcements had been made, after gas prices began to fall, and after reforms to California's air quality regulations had been announced.

In the winter and early spring of 2001, estimates abounded that the crisis would continue two to four years. Dr. Hogan even echoed these statements. Again, long term contract prices followed spot prices on a month by month basis. While the announcements of new plant construction were public and well understood by all participants, long term prices stayed high.



Once FERC began to intervene significantly in the market, spot prices fell dramatically. Again, long term prices fell in sync.

In a world where fundamentals were unable to explain long term contract prices, it is theoretically clear that any market participant had to be guided by opportunity cost. So long as the crisis was predicted to last two to four years, pricing a long term contract at less than these unjust and unreasonable prices would have been foolish As a result, buyers were between a rock and a hard place. Anyone offering a long-term contract could explain that without a long term contract, buyers were stuck buying at (unjust and unreasonable) spot prices. The price of long-term contracts rose to meet this opportunity cost.

When the crisis ended, both spot and long term prices returned to normal historical levels. Once prices were driven by fundamentals again, the theoretical argument that long term prices and short term prices differed returned to force.

Q. CAN THE FAILURE OF THE RESPONDENTS' THEORY TO MATCH THE FACTS BE DEPICTED GRAPHICALLY?

A. Yes. Exhibit SNO-64 unfolds to show the structure of prices over the period of the market failure. I have also included a number of salient events over this period. . A look at the course of events demonstrates that the changes in prices in both the spot and forward markets observed at the time are closely associated not with changes in market fundamentals as advocated by respondents, but with, first, the onset of market manipulations and withholding in May 2000 and the overdue action by FERC to correct these structural flaws in the California system in April and June 2001.

Q. CAN YOU GO THROUGH AND SUMMARIZE THIS CHART?

A. Yes.

The California restructuring experiment started in April of 1998. While the market was never smooth, major failures were the exception rather than the rule.

A major warning that problems were on the way occurred on May 25, 1999. On that date, Tim Belden, Enron's Vice President of Western Trading, scheduled 2,900 megawatts across a line in central Nevada with a capacity of less than 50 megawatts. This maneuver was a "proof of concept" that showed how fraudulent scheduling could destabilize the California markets. The Power Exchange investigation indicated that this one maneuver raised spot prices 71% on the day.

On the following day, FERC approved the California Power Exchange's plan to establish their own futures market. NYMEX had started their two forward markets, COB and Palo Verde on March 29, 1996 and September 15, 1996.

In October of 1999, the WSCC annual 10 year study showed adequate reserves though 2003.

In January, 1999, the Columbia River runoff is estimated at 100% by the "early bird" forecast[2].

[2] 20000313 ClearingUp, page 5

In March, the WSCC summer assessment indicates a reserve margin of 29.2% for May 2000. This report, like the updated report issued in May indicates confidence for the WSCC as a whole, but it does note that additional imports into California may be required.

On April 11, 2000, Enron's "fundies" group summarizes the situation. They made no mention of an impending crisis.

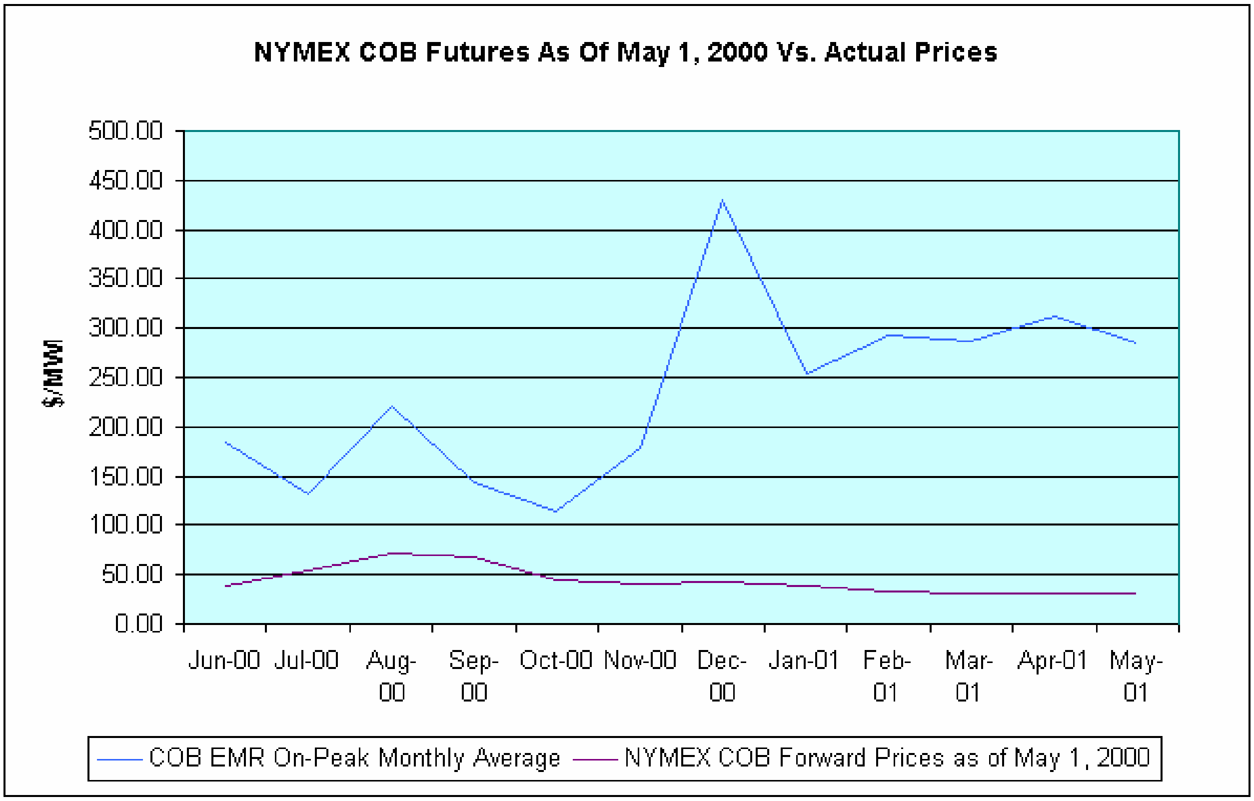
On May 1, 2000, Tim Belden sends his presentation on Western Power Markets to John Lavarato, CEO of Enron Americas, with no mention of the impending crisis. Belden slides include the phrase "west power is a solvable problem."[3] A second presentation from Enron's fundies group also does not mention the impending disaster.

WSCC reserves after load, forced outages, planned outages, and unavailable generation in May are 24,211 MW above loads. This is roughly the equivalent of 100 GE Frame 7 combined cycle plants.

NYMEX futures on May 1, 2000 show no inkling of the storm that is about to break.

---

[3]Western Power Markets, Tim Belden, May 3-4, 2000.



On May 12, 2000, Belden sends an email to his colleague, Greg Piper, with the suggestive message "We long. Pricing keep going up. So far so good."[4]

The market failure started on May 22, 2000. The California ISO issues a Stage 2 Emergency.

[4]Email from Tim Belden to Greg Piper, May 12, 2000.

On May 23, 2000, Tim Belden sends an email to the senior management of the ISO complaining that his 800 MW uninstructed generation in California only received $129.77, $300.00, and $379.29 for hours 17, 18, and 19.[5] Enron's decision to pull 900 MW's out of the ISO and PX markets may well have initiated the May 22, 2000 emergency.

Seattle City Light and Portland General Electric implement programs to provide incentives for industrial curtailments.

On June 13, 2000, the ISO issues a Stage 1 Emergency notice. From May 22, 2000 through September 20, 2000 the ISO issues Stage 1 and Stage 2 Emergency warnings approximately every third day.

In August, the WSCC reserve margin dips to 13.5% with only a margin of 17,365 MW between plant capacity and load. This is equivalent to only 75 GE Frame 7 combined cycle units.

On August 25, 2000, Enron makes an undocumented presentation to FERC explaining

[5] Workpapers at 20000523 Belden to Fluckiger.pdf,, email from Tim Belden to ISO (Fluckinger, Lazic, and Winter) 5/23/2000.

that the crisis is due to fundamentals.[6]

Throughout the fall, Tim Belden and others popularize the view that the crisis will work out in two to four years.

On August 28, 2000, Tim Belden suspends further "Get Shorty" transactions until "someone who knows almost nothing about ISO scheduling can implement the procedure." An additional reason is that the California Attorney General is in search of a smoking gun.[7]

Plant operations within the California ISO control area are poor. Over the entire period of market failure, thermal operations from the steam units owned by Reliant, Dynegy, Mirant, Duke, and AES/Williams only average 55.6% of capacity during Stage 1 Emergencies and 54.3% of capacity during Stage 2 Emergencies.

The summer's emergencies come to an end on September 20th. Prices abate mildly. The climb of forward prices pauses temporarily. In October, the reserve margin again passes 20%.

---

[6]Presentation To FERC, May Hain, August 24, 2000.

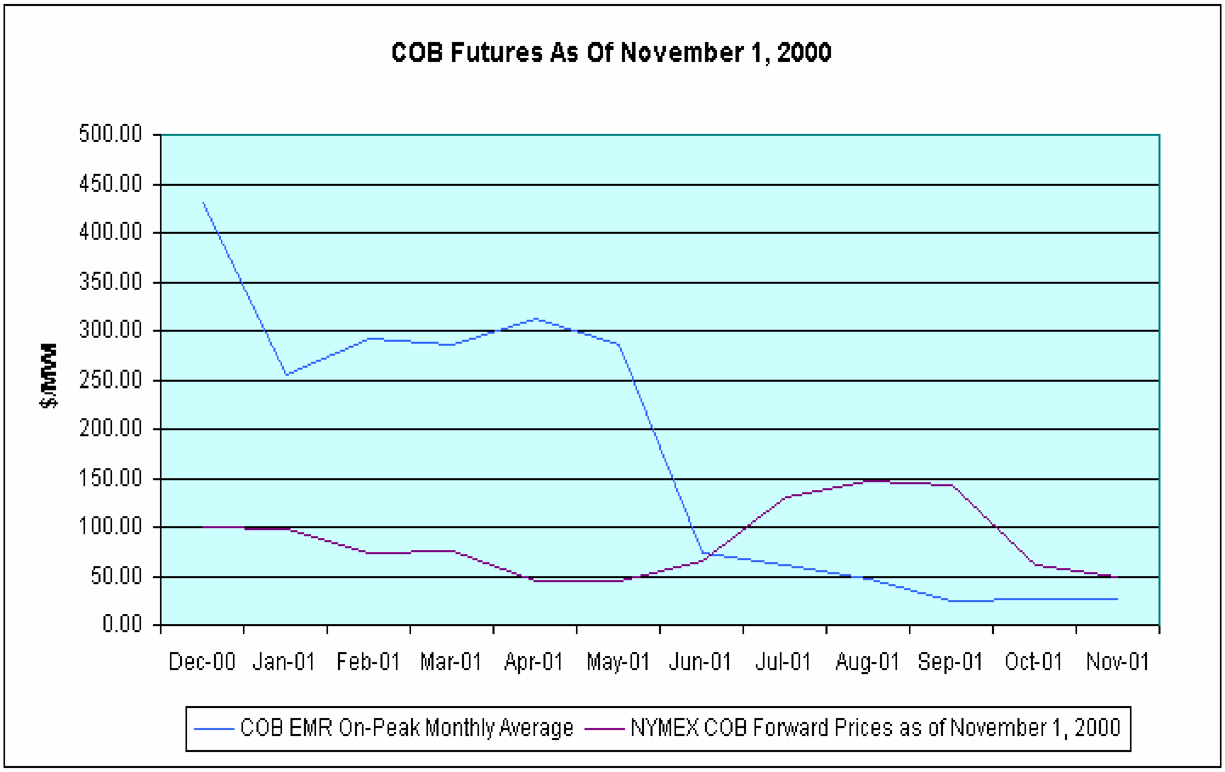
October 11, 2000 presentation by Robert McCullough gains wide visibility on the causes of the California market failure. The presentation also reveals that the California ISO has been providing operating data back to the generators through the Electric High Voltage (EHV) database[8] in contravention of its own secrecy tariff.

October 12, 2000, the ISO withdraws from the EHV data base.

On November 13, 2000, the California ISO declares a Stage 2 Emergency. The WSCC reserve margin is 21.9% with 23, 906 MW of resources above load. This news is even more astounding that the emergency in May. Forward prices begin a steady climb.

---

[7]Email from Tim Belden to Greg Wolfe, Chris Foster, John Forney, and Jeff Richter, August 28, 2000.
[8]The EHV database is maintained by the WSCC.

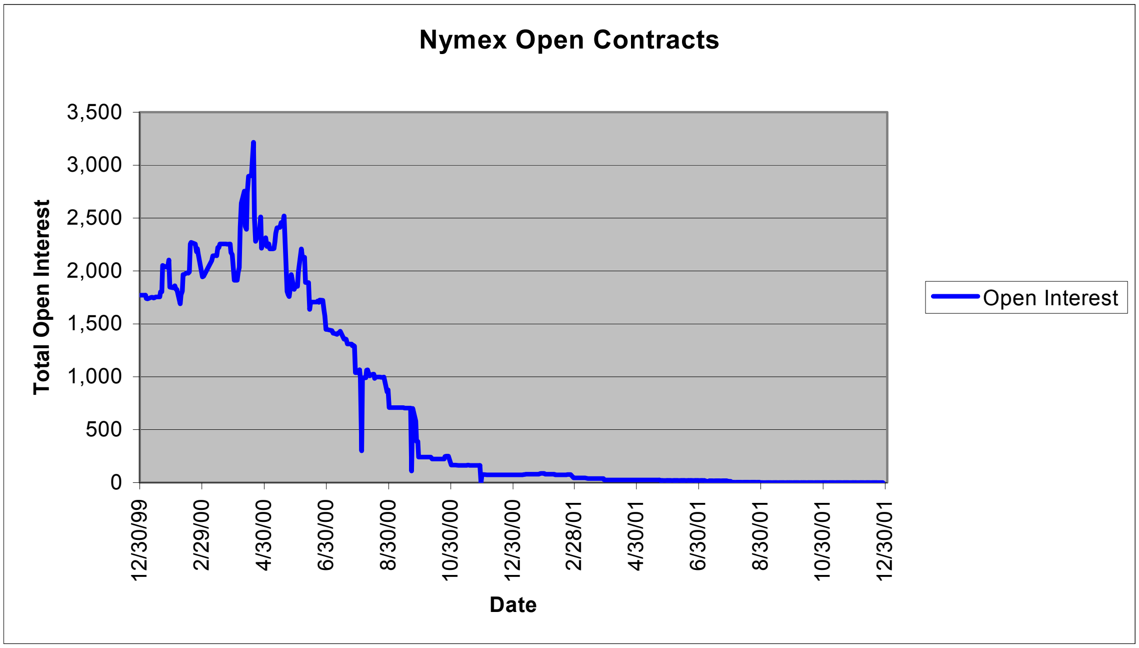


Forward markets again fail to predict the dramatic change.

NOx prices increase at the SCAQMD. The basis between natural gas prices in California and the rest of the United States increases dramatically.

Numerous plants owned by Reliant, Dynegy, Duke, AES, and Mirant are taken down simultaneously for extended periods.

On November 22, 2000, Drs. Hogan and Harvey present a paper stating that the



California market does not work.

Volatility and lack of market transparency gradually eliminate activity on the "open cry" forward markets. In November, the NYMEX falls below 100 open contracts.

On December 7, 2000, the California ISO announces its first Stage 3 Emergency.

On December 15, 2000, FERC removes tariff approval for the California PX. This effectively ends the only other transparent forward market on the West Coast.

On December 21, 2000, Robert McCullough briefs the Public Power Council and the staff for Governor Kitzhaber of Oregon that we no longer had any ability to understand or forecast operations at the California ISO.

In January, 2001, the Columbia River runoff is estimated at 76% by the "early bird" forecast.

January 4, 2001, CPUC approve first emergency rate increase.

January 5, 2001, the U.S. Secretary of Energy issues an emergency order to aid the California ISO. It allows the ISO to take surplus energy from other control areas in the WSCC.

January 6, 2001, Governor Davis announces licensing of numerous plants for summer 2001.

On January 19, 2001, SCAQMD staff propose Rule 2020, reducing RTC costs to $7.50/lb consistent with the philosophy in Rule 2015 Backstop Provisions.

Starting on January 16, the ISO issues the first of 32 Stage 3 Emergencies. The WSCC reserve margin is 17.5% in January, 22.2% in February, 25.7% in March, and 21.7% in April. Surplus capacity averages approximately the equivalent of 100 GE Frame 7s over this period.

On February 28, 2001, Enron's new generation report forecast 4,000 MW online in 2001.

On March 7, 2001, Enron staff schedule a meeting to discuss the legal issues from the "pending summer melt down."[9]

On March 25, 2001, Tim Belden again predicts that "Things will get worse before they get better."[10]

March 27, 2001, CPUC approves major rate hikes for PG&E and SCE.

In April, the early bird forecast lowers its estimate of the Columbia River run-off to 53%.

The April 3, 2001 Enron new generation report predicts 5,118 MW of new resources in the summer of 2001.

Forward prices in April stand at their highest level in the crisis. Spot prices begin to fall.

April 25, 2001, FERC issues its order for limited price caps and a "must offer" rule.

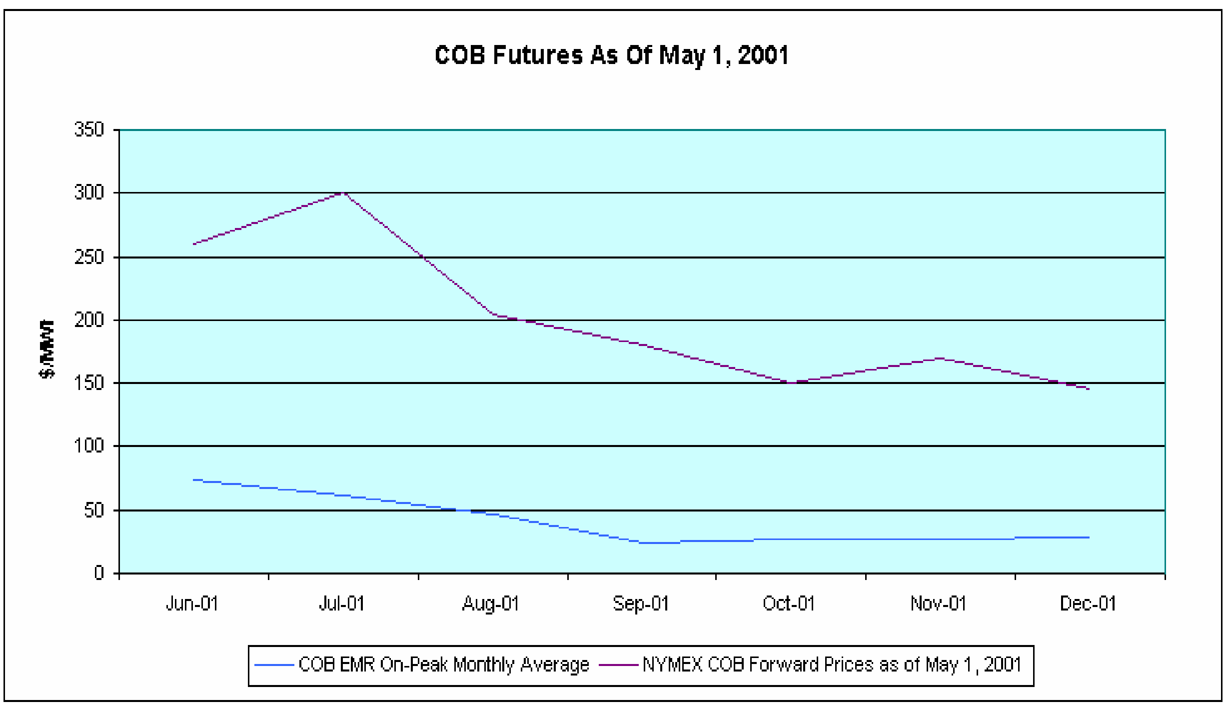
---

[9]Email from Christian Yoder to Richard Sanders and others, March 7, 2001.

Forward markets again miss the turning point.

May 8, 2001, last Stage 3 Emergency takes place.

May 29, 2001, FERC ordered price mitigation program goes into effect.



[10]Fundamental Supply Factors Driving Current Market Prices, March 25, 2001.

On June 13, 2001, Dr. Hogan assures the Senate that "it is likely that the problems of high prices and rolling blackouts will be with us again this summer."[11]

Average spot prices at COB diminish by 75%. Average forward strip prices at COB diminish by 59%. The WSCC reserve margin stands at 21.0%, less than the reserve margin in February through April.

FERC extends the price mitigation mechanism throughout the WSCC on June 19, 2001. In July, WSCC reserve margins fall to 16.1%. Spot prices fall an additional 16% in July, while one year forward strips fall 33%.

July 3, 2001, final Stage 1 and 2 Emergencies take place.

In August, the reserve margin stands at 18.4%, spot prices fall 25% and long term prices fall 36%.

Q. HOW DOES THE ACTUAL HISTORY OF THE PERIOD MATCH THE RECONSTRUCTIONS AND THEORIES OF THE RESPONDENTS?

A. Very poorly. Forward markets failed to predict any of the turning points. This is not surprising since their information was based on the same fundamental analysis that had

[11] Committee on Governmental Affairs, United States Senate on June 13, 2001.

prevailed for years before – reserve margins, fuel costs, and water years. Even industry insiders failed to correctly forecast the turning points, in part because the unpredictable element was a shift in political philosophy at FERC. Specifically, FERC-ordered price caps and must-offer requirements gave producers no incentive to hold power off the market to raise prices.

Q. WHAT CRITICAL FUNDAMENTALS INFORMATION ARRIVED IN MAY AND JUNE THAT CHANGED THE FORWARD MARKETS?

A. There wasn't any. New resource plans were well known and announced. Hydroelectric forecasts had been available, as always, since January. Drs. Harvey and Hogan can argue that market participants were surprised when SCAQMD adopted the proposed pricing from January, but this did not come to a surprise to anyone else in the market. Load forecasts were in hand, and the various emergency programs were well publicized.

Q. WHAT DID EXPLAIN THE COLLAPSE IN FORWARD PRICES?

A. Traders discovered that their opportunity cost had collapsed. The simple test for economic rationality had changed – traders could feel comfortable making offers now that the crisis appears to have abated.

SECTION 2: PLANNING CRITERIA

Q. WHAT APPEARS TO BE THE BASIC THEORY OF THE SHORTAGE AS ESPOUSED BY DRS. HARVEY AND HOGAN?

A. Stripped of the stage dressing, Drs. Hogan and Harvey believe there was a shortage because prices went up. The theory does not fit the facts. Reserve margins were above

20% for most months of the crisis and fell below 20% even as spot market prices collapsed in the summer of 2001.

Q. WHAT IS THE BASIS FOR THE RELIABILITY CALCULATIONS USED IN THE WSCC?

A. The WSCC publishes a manual entitled "Reliability Criteria" that is used to guide utility reliability planning throughout the WSCC. The current version is dated April, 2002.

Q. WAS THIS MANUAL CITED IN THE TESTIMONY OF MSCG OR EL PASO?

A. No. In spite of the frequent statements that shortages had occurred from load growth and low hydro, neither pieces of testimony apparently knew of or cited the basic source.

Q. WHY IS THIS RELEVANT?

A. The whole basis of electric utility planning is based on providing sufficient capacity to meet customer needs in spite of warm (or cold) weather, low hydro, and plant or transmission outages. The industry has been dealing with these, and other risks, for many years.

Specifically, on an annual basis, the WSCC plans ahead for a full ten years. Even though some market participants have argued that reliability should be secret as well, this is still open to public review and scrutiny.

Q. PLEASE EXPLAIN THE IMPORTANCE OF CAPACITY IN ELECTRIC RELIABILITY PLANNING.

A. Capacity reflects the ability of each resource to meet peak loads in a reliable fashion. WSCC rules make it clear that the estimated capacity for each unit is actual, not nameplate, not estimated.

Q. THIS PLANNING PROCESS IS DESIGNED TO AVOID ELECTRICITY SHORTAGES, CORRECT?

A. Yes. Since it is difficult to add capacity to the electric system and firm loads tend to be price insensitive in the short run, periods when peak loads exceed capacity would lead to brown outs and, possibly, a system collapse. Accordingly, electric systems plan to operate with capacity significantly above expected loads.

Q. WHAT IS A USUAL RESERVE MARGIN?

A. Actually, there is no all-purpose reserve margin. The old engineering rule of thumb was 5% plus the single largest contingency. In the WSCC, this would be approximately 10% if the single largest contingency was assumed to be the California Oregon Intertie (4,300 megawatts.) An enormous debate has occurred about the size of a responsible reserve margin over the years. Utilities facing "used and useful" regulatory tests have often argued that a high reserve margin would be useful.

Q. IS THERE A GENERAL NUMBER THAT MOST INDUSTRY PARTICIPANTS WOULD RECOGNIZE?

A. Yes. As a general rule, reserve margins in the 15% range are often regarded as usual.

Q. HAVE WE EVER ESTABLISHED A REASONABLE RESERVE MARGIN FOR THE ENTIRE WSCC?

A. Yes. The entire role of the WSCC is to consider the reliability in the member systems. Each year the WSCC produces appreciations of the load/resource balance. Their analysis is vastly more sophisticated than simply setting a reserve margin, but the reserve margins they have observed from their analysis are reported and the overall reliability of the systems is summarized. The WSCC undertakes a far more detailed reliability review than a simple test for reserve margin alone.

Q. DRS. HOGAN AND HARVEY (EX. MSC-65 AT 13-17) APPARENTLY BELIEVE THAT LOW HYDRO CAN REDUCE CAPACITY. IS THIS CORRECT?

A. No. WSCC planning specifically assumes adverse hydro. Capacity estimates are based on drought conditions. The Pacific Northwest observes an energy constraint because the energy available from hydro, even with storage, can fall below average load in a year. A central part of reliability planning for the Pacific Northwest is to avoid this risk. The planning is conducted according to the Coordination Agreement.

Q. DID DRS. HARVEY AND HOGAN CITE THIS RELIABILITY STANDARD EITHER?

A. No. To put it succinctly, Drs. Hogan and Harvey found there was a shortage without referencing either of the critical documents on reliability used in the WSCC.

Q. ON WHAT BASIS DO THEY CLAIM THERE WAS A SHORTAGE?

A. Their assertion appears to be based on the combination of two factors: that peak loads have increased over time and that hydro generation was down in 2000. These assertions do not by themselves demonstrate a shortage. On the contrary, because WSCC planning criteria assume poor water conditions, the fact that hydro generation declined in 2000 over the two previous very wet years proves only that the available *non-firm* energy from the hydro system declined, not that there was an actual shortage. Indeed, Hogan and Harvey do not explain how these changes affected the total supply-demand balance. A review of the WSCC reserve margins for the crisis period demonstrates that the "shortage" theory simply can't explain the price excursions that occurred. Nor can it explain the sudden drop in prices in mid-2001, just as reserve margins were beginning to tighten again.

Q. DOES THE WSCC CONSIDER LOAD GROWTH AND WARM WEATHER IN MAKING ITS RELIABILITY CALCULATIONS?

A. Yes. The WSCC considers droughts as well. None of the factors cited by Drs. Harvey and Hogan are new, surprising, or difficult to understand.

Q. ARE THERE ANY REASONS TO BELIEVE THAT HIGH PRICES DON'T NECESSARILY IMPLY SHORTAGE?

A. Yes. All in all, their position is completely unsupportable. On a theoretical basis, the availability of 17,365 megawatts of resources over firm loads in August of 2000, means that prices should have been set by the cost of the least efficient unit dispatched. In reality, prices through much of the crisis were set by emergency purchases when the cumbersome machinery of the California energy markets failed to provide sufficient energy and capacity to serve loads.

The following charts shows the summary of actual loads and resources for the WSCC during the market failure[12].

[12] WECC Summary of Estimated Loads and Resources Date as of January 1, 2001, Issued May 2001 and January 1, 2002 Issued May 2002

WESTERN SYSTEMS COORDINATING COUNCIL
SUMMARY OF ACTUAL LOADS AND RESOURCES
TOTAL WSCC REGION

ACTUAL YEAR 2000
ACTUAL HYDRO CONDITIONS

PEAK DEMAND - MEGAWATTS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
LOADS - FIRM	110063	105410	104091	106299	115892	123799	129030	128696	121640	109886	109042	113525
INTERRUPTIBLE AND LOAD MGT	3779	3824	3800	3848	3957	3868	1862	2174	2214	4044	4065	2579
TOTAL LOAD	113842	109234	107891	110147	119849	127667	130892	130870	123854	113930	113107	116104
RESOURCES - HYDRO - CONVENTIONAL	59846	59474	59968	60390	60841	61404	61324	61140	61359	61213	60242	59927
HYDRO - PUMPED STORAGE	4426	4426	4426	4052	4052	4052	4052	4052	4052	4110	4426	4426
STEAM - COAL	36522	36522	36522	36522	36522	36503	36495	36495	36503	36522	36522	36522
STEAM - OIL	746	746	746	746	746	746	596	596	596	596	596	596
STEAM - GAS	23310	23310	23310	23303	23289	23280	23430	23430	23433	23456	23460	23460
NUCLEAR	9343	9343	9343	9343	9263	9263	9263	9263	9263	9263	9343	9343
COMBUSTION TURBINE	10594	10594	10568	10580	10342	10647	10673	10673	10771	10949	11164	11211
COMBINED CYCLE	7880	7873	8316	8192	8241	8371	8366	8364	8371	8569	8632	8708
GEOTHERMAL	2351	2351	2351	2319	2369	2419	2469	2469	2469	2501	2501	2501
INTERNAL COMBUSTION	272	272	272	273	273	273	281	281	281	280	288	288
OTHER	1771	1771	1771	1757	1751	1765	1766	1766	1766	1791	1791	1791
TOTAL RESOURCES	157061	156682	157593	157477	157689	158723	158715	158529	158864	159250	158965	158773
FORCED OUTAGES	3974	6363	5971	9888	8652	6892	5223	4613	4732	7864	7719	6335
INOPERABLE CAPABILITY	370	426	427	390	506	481	522	777	796	834	810	846
SCHEDULED MAINTENANCE	9056	10156	14337	16025	8891	7674	5045	7844	9705	12439	18309	13705
TOTAL UNAVAILABLE CAPABILITY	13400	16945	20735	26303	18049	15047	10790	13234	15233	21137	26838	20886
NET RESOURCES	143661	139737	136858	131174	139640	143676	147925	145295	143631	138113	132127	137887
FIRM/JOINT PART. IMPORTS - MAPP	-250	-320	-251	-146	-214	-415	-193	-488	-417	-603	-623	-630
SWPP	-225	-250	-250	-250	-300	-300	-290	-290	-290	-300	-200	-50
TOTAL IMPORT	-475	-570	-501	-396	-514	-715	-483	-778	-707	-903	-823	-680
FIRM/JOINT PART. EXPORTS - MAPP	0	0	1	58	51	56	31	12	0	2	2	1
TOTAL EXPORT	0	0	1	58	51	56	31	12	0	2	2	1
NET EXPORTS/IMPORTS	-475	-570	-500	-338	-463	-659	-452	-766	-707	-901	-821	-679
JOINT PARTICIPATION TRANSFERS	0	0	0	0	0	0	0	0	0	0	0	0
NET FIRM TRANSFERS*	-475	-570	-500	-338	-463	-659	-452	-766	-707	-901	-821	-679
NET RESOURCES AND NET TRANSFERS	144136	140307	137358	131512	140103	144335	148377	146061	144338	139014	132948	138566
MARGIN OVER FIRM LOAD - MW	34073	34897	33267	25213	24211	20536	19347	17365	22698	29128	23906	25041
MARGIN OVER FIRM LOAD - PERCENT	31.0	33.1	32.0	23.7	20.9	16.6	15.0	13.5	18.7	26.5	21.9	22.1

*NET EXPORTS/IMPORTS LESS JOINT PARTICIPATION TRANSFERS (MINUS SIGN INDICATES PURCHASE).
JOINT PARTICIPATION GENERATION IS INCLUDED BY TYPE UNDER "RESOURCES" IN EACH PARTICIPANT'S AREA.

PUBLIC DOCUMENT – PAGES 95-97, 99-100, 102-103, 115 CONTAIN PRIVILEGED INFORMATION

WESTERN ELECTRICITY COORDINATING COUNCIL
SUMMARY OF ACTUAL LOADS AND RESOURCES
TOTAL WECC REGION

ACTUAL YEAR 2001
ACTUAL HYDRO CONDITIONS

PEAK DEMAND - MEGAWATTS	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
LOADS - FIRM	112506	110086	102906	104421	115715	119199	122501	123193	115235	113564	108803	112716
INTERRUPTIBLE AND LOAD MGT	1571	1084	1332	1336	529	1862	1877	1847	1883	1219	1297	1288
TOTAL LOAD	114077	111170	104238	105757	116244	121061	124378	125040	117118	114783	110100	114004
RESOURCES - HYDRO - CONVENTIONAL	57395	56879	56906	57176	57939	58230	56512	56153	55916	55678	55235	57460
HYDRO - PUMPED STORAGE	4386	4386	4386	4076	4076	4076	4076	4076	4076	4070	4386	4386
STEAM - COAL	36617	36617	36617	36617	36617	36598	36590	36590	36598	36617	36617	36636
STEAM - OIL	564	564	414	414	414	414	414	414	414	414	414	414
STEAM - GAS	23298	23298	23448	23441	23436	23526	23526	23526	23526	23544	23535	23617
NUCLEAR	9302	9302	9302	9302	9263	9263	9263	9263	9263	9263	9302	9302
COMBUSTION TURBINE	10358	10383	10361	10182	10401	10608	11279	11495	12085	12501	12686	13278
COMBINED CYCLE	10012	10005	9999	10037	9971	11793	13421	13419	13508	14313	14667	14781
GEOTHERMAL	2605	2605	2605	2618	2618	2618	2618	2618	2618	2605	2605	2605
INTERNAL COMBUSTION	261	261	261	261	261	261	261	297	297	297	297	315
OTHER	2964	2963	3014	3027	3075	3103	3122	3185	3258	3266	3267	3117
TOTAL RESOURCES	157762	157263	157313	157151	158071	160490	161082	161036	161559	162568	163011	165911
FORCED OUTAGES	5765	6475	7800	6674	8573	5463	8302	3452	5300	6387	9213	7878
INOPERABLE CAPABILITY	5038	4064	4015	5334	2772	2669	3463	4128	4668	3980	3823	3580
SCHEDULED MAINTENANCE	15297	12626	16605	18467	15462	8546	7297	7945	10664	15242	16929	16131
TOTAL UNAVAILABLE CAPABILITY	26100	23165	28420	30475	26807	16678	19062	15525	20632	25609	29965	27589
NET RESOURCES	131662	134098	128893	126676	131264	143812	142020	145511	140927	136959	133046	138322
FIRM/JOINT PART. IMPORTS - MAPP	-234	-129	-174	-174	-148	-193	-132	-157	-46	-88	-285	-143
SWPP	-303	-318	-303	-303	-200	-303	-153	-278	-303	-200	-303	-232
TOTAL IMPORT	-537	-447	-477	-477	-348	-496	-285	-435	-349	-288	-588	-375
FIRM/JOINT PART. EXPORTS - MAPP	45	40	34	35	36	33	50	48	62	33	39	118
TOTAL EXPORT	45	40	34	35	36	33	50	48	62	33	39	118
NET EXPORTS/IMPORTS	-492	-407	-443	-442	-312	-463	-235	-387	-287	-255	-549	-257
JOINT PARTICIPATION TRANSFERS	0	0	0	0	0	0	0	0	0	0	0	0
NET FIRM TRANSFERS*	-492	-407	-443	-442	-312	-463	-235	-387	-287	-255	-549	-257
NET RESOURCES AND NET TRANSFERS	132154	134505	129336	127118	131576	144275	142255	145898	141214	137214	133595	138579
MARGIN OVER FIRM LOAD - MW	19648	24419	26430	22697	15861	25076	19754	22705	25979	23650	24792	25863
MARGIN OVER FIRM LOAD - PERCENT	17.5	22.2	25.7	21.7	13.7	21.0	16.1	18.4	22.5	20.8	22.8	22.9

*NET EXPORTS/IMPORTS LESS JOINT PARTICIPATION TRANSFERS (MINUS SIGN INDICATES PURCHASE).
JOINT PARTICIPATION GENERATION IS INCLUDED BY TYPE UNDER "RESOURCES" IN EACH PARTICIPANT'S AREA.

Q. WHAT IS THE WORST SINGLE MONTH FOR THE WSCC AS A WHOLE?

A. The worst month is August 2000 in terms of the margin, followed very closely by May 2001. Hydro electric output, of course, was considerably lower in 2001.

Q. DID THE WSCC EVER COME CLOSE TO RUNNING OUT OF CAPACITY?

A. No. In absolute terms the worst month was the very end of the market failure period. In May of 2001, the WSCC tabulation shows a margin over firm load of 15,861 megawatts.

Q. CALIFORNIA HAS ONLY HAD A RESTRUCTURED ELECTRICITY MARKET SINCE 1998; HOW DID CALIFORNIA ENSURE THAT ITS RESOURCES WERE SUFFICIENT TO MEET LOAD PRIOR TO THAT TIME?

A. To some degree, each major utility did its own capacity planning, with coordination through the California Energy Commission and the WSCC.

Q. PRIOR TO 1998, WHAT STANDARD WAS USED FOR A RESERVE MARGIN?

A. Again, there is no hard and fast rule, and were are incentives for investor-owned utilities to prefer relatively high margins. However, we can gain some insight from past documents.

Q. WERE THERE OTHER DOCUMENTS THAT WERE FILED IN THIS PROCESS?

A. Yes. In 1990, the California Energy Commission appointed a committee to create the 1990 Electricity Report (ER 90). This report was an extensive state-wide plan for electricity, that included recommendations for balancing loads and resources for all of the major utilities in the state. That report suggested reserve margins of between 15% and 18% be used for planning the systems of various large utilities in California, with various justifications for margins being acceptable down to the 11.5%-12% range for certain cases.[13]

Q. ARE THERE OTHER EXAMPLES OF PLANNING PROCESSES THAT RESULTED IN SIMILAR RESERVE MARGINS?

A. Yes. The California Energy Commission appointed a committee to create the 1994 Electricity Report (ER 94). Again, there was no one simple formula for determining a single appropriate reserve margin, but the planning reserve margin for the largest utilities was set at 15.5%-16%.[14]

These calculations were also applied, with similar results, in the PG&E 1996 general rate case. The results reiterated a PG&E target reserve margin of 15.5%.[15]

SECTION 3: THE FACTS OF THE CALIFORNIA CRISIS

Q. CAN YOU CHARACTERIZE THE ARGUMENTS OF THE RESPONDENTS?

A. Rather than looking at overall reserve margins, as would be standard practice in determining whether a shortage exists (more accurately, whether reserve margins have fallen to critically low levels), respondents attempt to construct a piecemeal portrait composed of different elements of the supply-demand balance. Ultimately, the different pieces do not add up to a story that can account for what happened during the crisis period.

---

[13] ER 90, Appendix D, pages D-59 to D-62.
[14] ER 94, Appendix A, Table A-I-A-27.

Q. WHERE DO MSCG WITNESSES HOGAN AND HARVEY START IN THEIR ATTEMPT TO EXPLAIN THE CRISIS AS A PRODUCT OF MARKET FUNDAMENTALS?

A. Harvey and Hogan (Ex. MSC-65 at 5-7) start their responsive testimony with California-Mexico Monthly Total Peak Load.

Table 1
CA-MX* Monthly Total Peak Load (MW): 1993-2001**

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1993***	37,811	35,187	34,052	35,955	39,744	48,666	45,885	49,664	48,673	42,866	36,154	37,750
1994***	36,231	35,653	34,819	36,665	37,221	51,392	48,834	52,668	47,153	38,065	36,957	37,922
1995***	37,150	35,595	35,789	35,046	39,350	46,232	51,420	52,510	49,229	41,292	36,564	37,628
1996***	37,438	37,229	36,082	43,169	43,285	49,142	54,541	54,760	48,450	45,639	37,938	39,121
1997	36,665	34,320	37,575	37,457	47,027	44,953	47,246	53,217	52,202	42,396	39,178	37,981
1998	36,691	35,885	35,561	37,334	33,886	41,909	49,857	54,586	55,441	40,667	35,982	38,304
1999	36,204	36,071	35,760	36,603	38,028	46,907	53,146	50,687	46,850	42,854	37,965	39,428
2000	37,720	37,358	37,548	39,861	45,947	50,449	50,387	51,213	49,304	41,398	38,442	37,993
2001	37,810	35,957	35,015	37,119	44,060	46,173	47,482	48,351	44,773	45,278	37,394	38,485

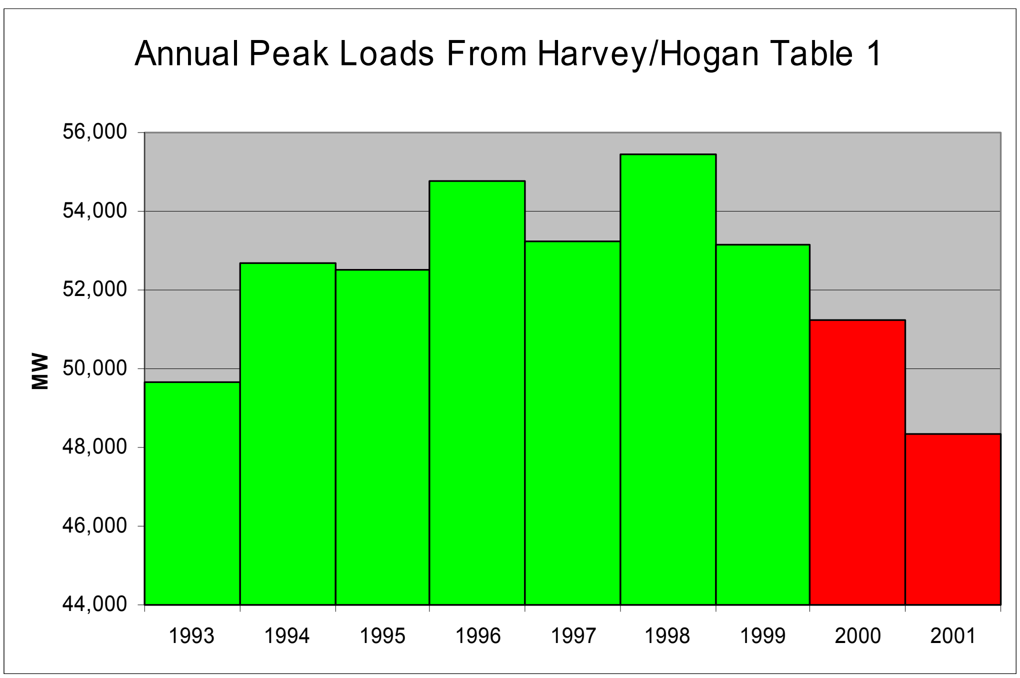
This table draws from the wrong set of data and Hogan and Harvey draw the wrong conclusion from it. They state:

> Table 1 shows that in May and June of 2000, peak load for the California-Mexico region of the WSCC was well above prior levels, accounting for the capacity shortage that contributed to elevated prices during these months. In the following months, peak load in this region was within the range of peak loads in prior years, until it began to decline markedly in June 2001, which is consistent with lower prices and diminished price spikes in June 2001. (Ex. MSC-65 at 5)

The following table takes the values from Table 1 and shows the annual peak load by year. Normal years are marked in green and market failure years are marked in red. Any

[15] PG&E's marginal generation capacity cost workpapers, 1996 general rate case (A. 94-12-005)

impartial party would look at this table and wonder why the market failure started in 2000 when loads were significantly higher in 1999.[16] While *peak loads in certain months* are higher than previous peaks, this can explain only short-term spot price spikes as occurred in previous summers, not the sustained price excursion that occurred in California for more than a year. Indeed, the table shows that peak demands were lower than previous years for February through June 2001, even though the spot and forward markets continued to increase in those months across the West



Q. DOES THIS TABLE DEMONSTRATE THE WEAKNESS OF RESPONDENTS'

[16]Drs. Harvey and Hogan include inconsistent data for 1993 through 1996 in this table which makes their position appear even weaker than it is.

THEORY?

A. Absolutely. Respondents' assertion that capacity shortages combined with growing demand lead to the California ISO emergency declarations simply is not supported by the data. The problem they face is that California peak loads declined enormously over this period. California peak loads were 92.3% of the 1998 levels in the first year of the crisis and fell to 87.2% of their 1998 levels in 2001. In fact, a close examination of the table reveals that peak demand was lower than had been experienced in previous years for *every month* in during the crisis except for June 2000

Q. IS THE USE OF CALIFORNIA PLUS MEXICO DEMAND USEFUL TO IDENTIFY THE CAUSES OF THE CRISIS?

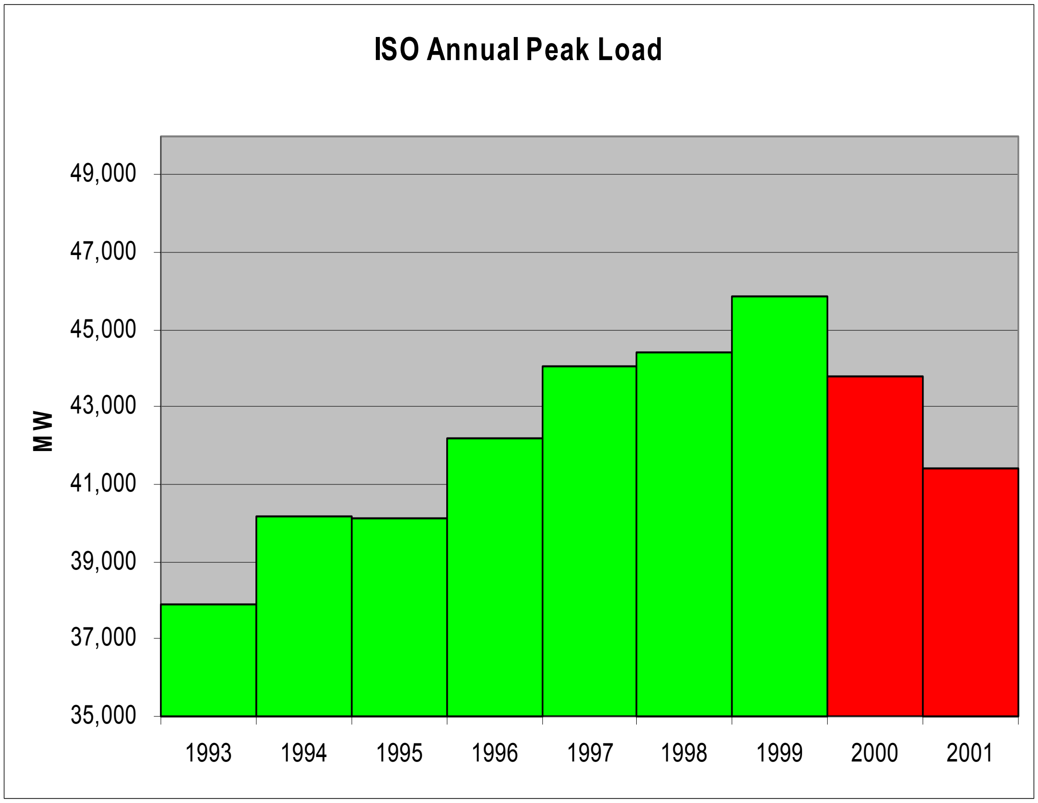
A. This is an interesting challenge. Choosing specific months (May and June) to obscure the fact that peak loads actually fell is only misleading. It is not an error. Attributing the capacity shortages to the higher levels in May and June is an error, since the ISO had been able to meet considerably higher peak loads in the past. The statement that peak loads were "within the range" of peak loads in prior years appears simply to be in error. I would characterize this paragraph as having two errors and one misleading statement.

Q. IS THIS ACTUALLY A VERY USEFUL GRAPH TO DISPLAY THESE FACTS?

A. No. For some reason, Drs. Harvey and Hogan have chosen California peak loads plus a small portion of Northern Mexico to describe the situation within the California ISO.

Q. WHAT HAPPENED TO PEAK LOADS AT THE CALIFORNIA ISO?

A. As with overall California peak loads, peak loads within the control area of the ISO fell over this period.



Within the ISO, peak loads were 95.4% of their 1999 levels in 2000 and 90.3% in 2001.

Q. WHY IS THIS RELEVANT?

A. In spite of the comments of Drs. Harvey and Hogan, the emergencies that took place where at the California ISO. Emergency declarations did not take place elsewhere within the WSCC. While they go on to produce several tables that show that loads went up in the WSCC, as a whole, this requires an intuitive leap to explain why rising loads outside of California would contribute the declared emergencies within California, especially given the adequate reserve margin across the WSCC at the relevant time. Special interest should be paid to Table 4 (Ex. MSC-65 at 8):

Table 4
WSCC* Monthly Total Peak Load (MW): 1993-2001**

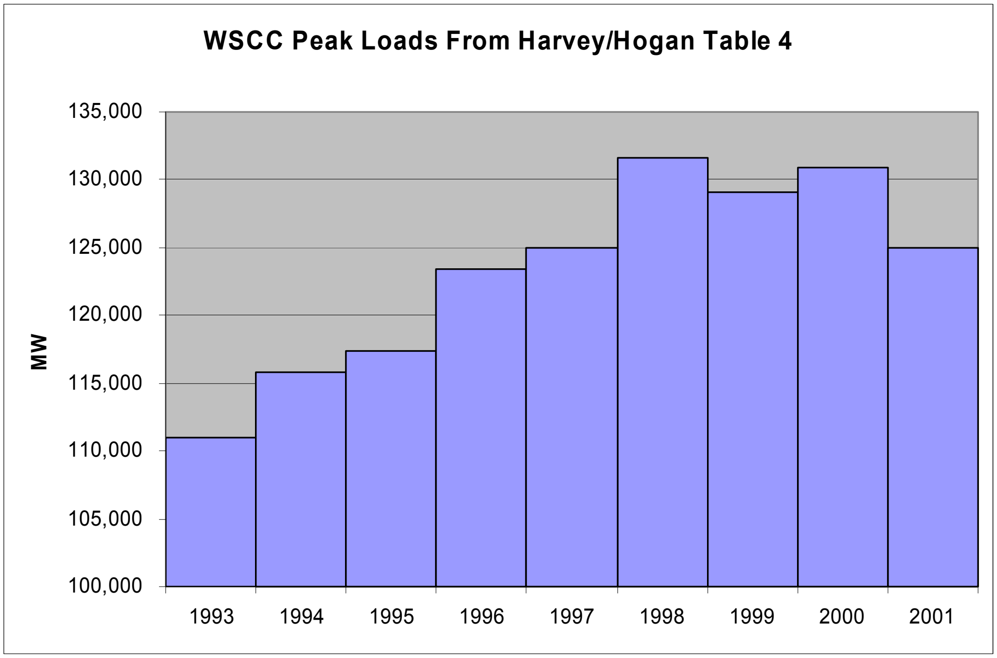
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1993	107,777	101,876	95,558	93,342	97,258	107,941	105,575	110,970	107,772	101,532	104,929	104,433
1994	101,675	103,982	94,855	94,942	95,052	114,608	113,062	115,826	107,361	97,595	104,113	107,542
1995	105,979	102,745	98,568	93,999	97,064	107,687	117,386	117,204	111,920	104,333	101,171	106,738
1996	112,232	111,147	101,578	104,188	105,789	113,108	123,375	122,417	112,226	111,415	104,688	111,917
1997	113,361	106,147	105,731	103,126	114,499	112,947	119,348	124,935	120,598	111,081	106,035	110,515
1998	112,937	106,317	105,116	103,121	98,741	112,785	127,731	131,680	128,349	108,660	105,688	120,122
1999	109,246	108,783	104,323	103,503	106,370	120,682	129,059	125,791	118,063	112,587	108,227	115,267
2000	113,842	109,234	107,891	110,147	119,849	127,667	130,892	130,870	123,854	113,930	113,107	116,104
2001	114,077	111,170	104,238	105,757	116,244	121,061	124,378	125,040	117,118	114,783	110,100	114,004

* WSCC Region definition includes Canadian and Mexican load.
** Total Peak Load is the sum of Firm Load and Interruptible Demand.
Sources: WSCC 10-Year Coordinated Plan Summaries: 1994-2001 (1993-2000)
http://www.wecc.biz/2001_Peak_Demands_and_Energy_Loads_05-15-02.pdf (2001)

As with Table 1 in their testimony, this table is cited as justifying their position, while it directly contradicts the point they are making. They say:

> Overall, Table 4 shows that WECC load rose to new peaks in January though July and October and November 2000, as well as January and February 2001.

The table in fact shows a very different story. The following table illustrates how the system peak in 2000 and 2001 compared to previous years:



The fact is that the system peak in 2000 was lower than the system peak in 1998, not higher.

Q. DID DRS. HOGAN AND HARVEY MAKE A MISTAKE IN CHARACTERIZING THEIR TABLE?

A. No. A careful review of their testimony shows that they left the peak month, August, out of their description of the graph.

Q. DRS. HOGAN AND HARVEY (MSC-65 AT 10-13) PROCEED TO DISCUSS LOAD REDUCTION EFFORTS. HOW ACCURATE ARE THEIR COMMENTS?

A. Although some of their comments are correct, the overall sense of this section of this testimony is in error. They have attempted to give the impression that Pacific Northwest utilities waited until 2001 to implement load reduction programs.

Q. IS THIS CORRECT?

A. No. Industrial load adjustments started immediately after the start of the market failure. In fact a large portion of Pacific Northwest industrial loads had direct market access or were priced a market indexed pricing. Pacific Northwest utilities adopted "capacity exchange" programs almost immediately after the onset of the market failure.

Q. WHEN WAS THE FIRST EXPLICIT PROGRAM ADOPTED?

A. Seattle City Light offered a load reduction program to its largest industrial – Birmingham Steel in May of 2000. Portland General Electric proposed their "capacity exchange" program at the beginning of the market failure. It was approved by the Oregon Public Utilities Commission on July 11, 2000. PacifiCorp's program was approved on December 6, 2000. BPA's program started with the buy back of energy from Daishowa in August of 2000. Most large industrial loads at PSE, PGE, and Pacific were on market indexed tariffs. Customers of these utilities adjusted their power purchasing immediately.

Q. DID THESE MARKET ADJUSTMENTS REQUIRE UTILITY PROGRAMS?

A. No. BPA had released its major industrial customers to the market in the mid-1990s. The customers who were buying from the market adjusted their operations quite quickly. Three large loads -- Kaiser, Vanalco and Troutdale -- stopped operations in June and October. Drs. Harvey and Hogan also neglected to mention the large closure of Cominco's metals zinc smelter in Trail, British Columbia on December 11, 2000.

Q. WERE ALL REDUCTIONS MINOR?

A. Not at all. Georgia Pacific Bellingham, a world class paper mill, eventually ceased operations entirely during the fall.

Q. WHEN WOULD MARKETS BE EXPECTED TO REFLECT THESE LOSSES OF LOAD?

A. Almost immediately after May 22, 2000. The impact of energy prices on industrial operations in the Pacific Northwest has been well understood since the early 1980s. Large industrials were sophisticated players and often were directly involved in the bulk power markets.

This points up the central problem with this part of the testimony: changes in the fundamentals in the market – industrial response to electric price changes, for example – took place far before the collapse of forward prices. They need to manhandle these events into a specific month to explain why spot prices and forward prices declined at the same time and in the same magnitude. In this case, they have attempted the impossible. Industrial adjustments to the market failure started in June and continued throughout the crisis. They were well reported in the press and well understood by market participants.

Q. DID ENRON KNOW ABOUT THEM?

A. Yes. Enron facilitated some of the transactions – Cominco, for example.

Q. DIDN'T ENRON ADJUST THEIR EXPECTATIONS ACCORDINGLY?

A. In fact, these load reductions did not change the forward perceptions at Enron, which would have been the case if the Hogan/Harvey theory is correct. As I will discuss in the next section, we know Enron did not change its market projections even in the face of these load reductions.

HYDROELECTRIC POWER OUTPUT

Q. **THE RESPONDENTS SPEND A SUBSTANTIAL AMOUNT OF TIME DISCUSSING HOW MUCH LOWER HYDROELECTRIC OUTPUT WAS IN 2000 AND 2001. WHY ARE THEY DOING THIS?**

A. Apparently, they believe that the capacity emergencies were caused by a shortage of energy from the Columbia River.

Q. DOES THIS HYPOTHESIS MAKE MUCH SENSE?

A. No. The region has a very well developed reliability planning process, as discussed in my section on reliability planning, above. Because of the importance of hydropower in the Northwest capacity – the ability to serve peak loads at a specific moment in time – is always calculated under adverse hydro conditions. Hydroelectric planning under the Coordination Agreement provides the same amount of capacity in a dry year as a wet year.

Q. IS THIS WELL UNDERSTOOD?

A. Yes. The WSCC planning documents (quoted in part by Drs. Harvey and Hogan) always assume adverse hydro conditions. This is why the term "adverse hydro conditions" is printed on the upper right hand corner of each table in the WECC Summary of Estimated Loads and Resources.

Q. WHAT IMPACT DOES THE ANNUAL CHANGE IN RUN-OFF FROM THE COLUMBIA RIVER HAVE ON POWER COSTS IN CALIFORNIA AND

THROUGHOUT THE WSCC?

A. Non-firm hydroelectricity – a term of art in the Pacific Northwest that reflects its potential lack of availability in future years – is used to displace thermal generation in the Northwest and throughout the WSCC.

Q. WOULD ANYONE DEPEND ON NON-FIRM TO PROVIDE CAPACITY RESERVES?

A. Not for long. By definition, non-firm hydroelectricity is not a firm commitment. In the real world, non-firm depends on the weather, the snow pack, environmental regulations, operations under the Coordination Agreement, and the individual decisions of hydro operators from Eugene to Trail.

Q. WAS THE WSCC DEPENDING ON NON-FIRM?

A. No. This would violate planning standards in both the WSCC and in the Pacific Northwest.

Q. SO WHAT ARE THE RESPONDENTS TALKING ABOUT?

A. Drs. Harvey, Hogan, and Kalt have confused plant displacement with capacity. The slightly below average run off in 2000 and the drought in 2001 reduced the ability to displace thermal generation in California and throughout the WSCC.

Q. WHAT WAS THE IMPACT OF THIS REDUCTION?

A. In a wet year, utilities can buy non-firm electricity to displace expensive thermal generation. In a very wet year, the amount of non-firm is so great that it can saturate the tie lines and actually reduce power prices to wheeling costs in the Pacific Northwest.

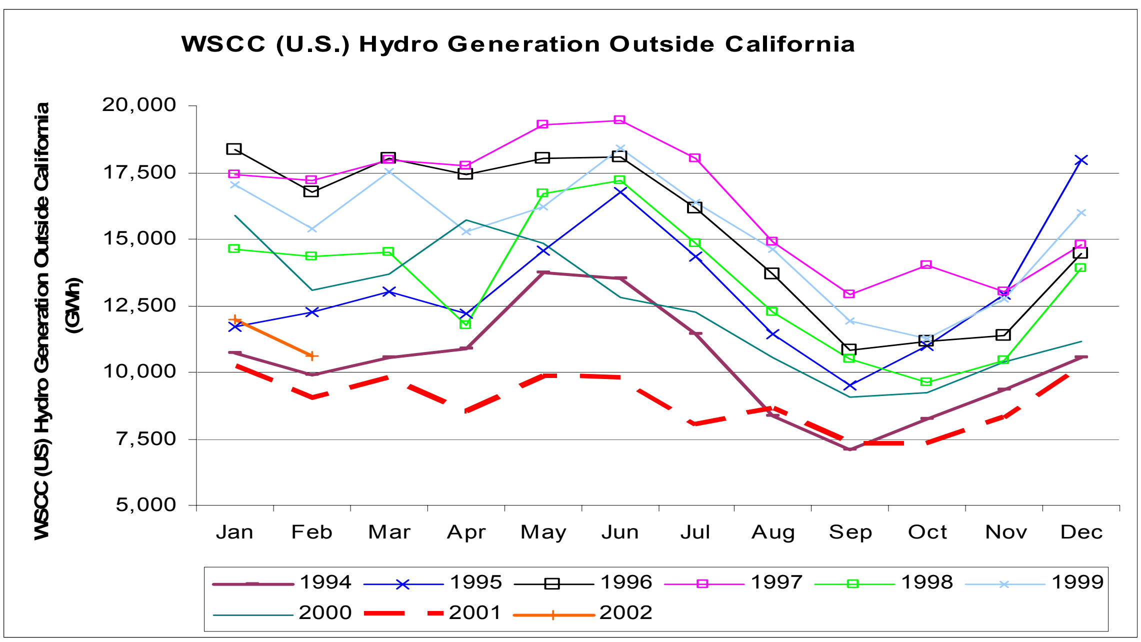
This, of course, was not the case here.

Q. ARE THERE ANY FACTUAL PROBLEMS WITH THEIR PRESENTATION ON REGIONAL HYDROELECTRICITY?

A. Yes. They only compared hydro generation during the market failure with wet years. As a matter of common sense, comparing a normal year with wet years only proves that more is larger than less.

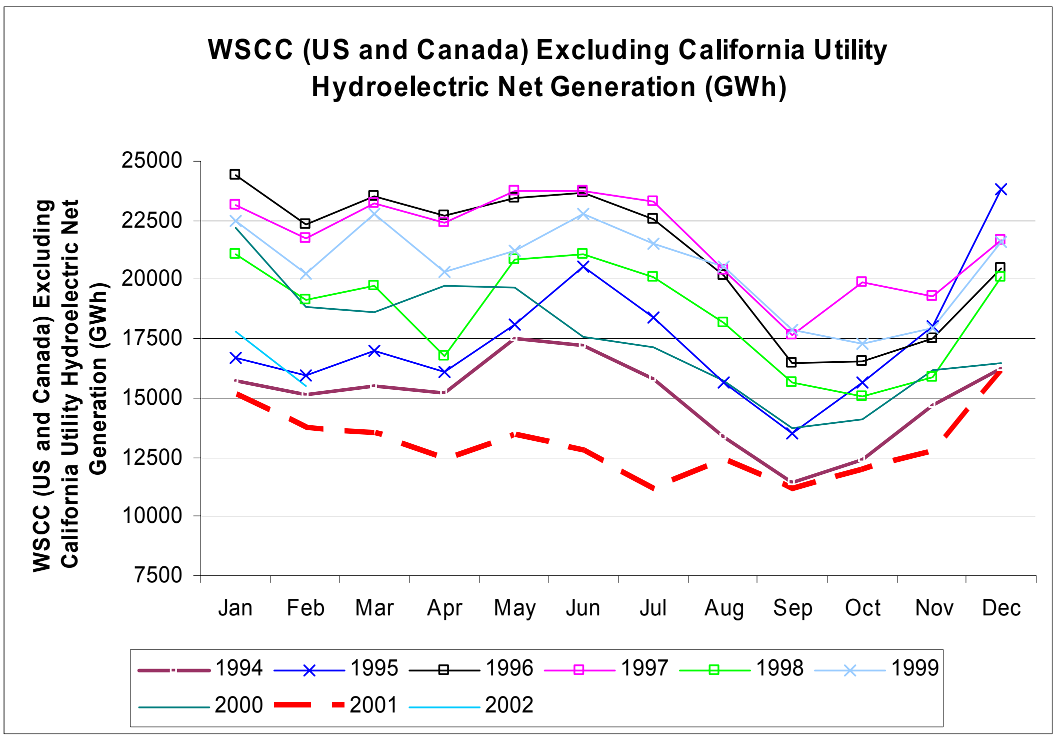
Q. WHAT DATA DID THEY FAIL TO PROVIDE?

A. Table 12, for example, simply forgets to include 1994, a low hydro year. The following table returns 1994, a year with low hydro to the chart.



Q. DO THEY FORGET TO INCLUDE ANY OTHER PERTINENT DATA?

A. Yes, Drs. Harvey and Hogan apparently overlooked the fact that much of the Columbia River is in Canada. Any serious review of hydroelectric output would not leave out the Canadian generation. The chart with Canadian hydroelectric generation is significantly closer to representing the actual situation in 2000.



Once the missing data is returned to the chart, it is clear that 2000 was an average year. Hydroelectric generation in 2000 was greater than drought years like 2001 and 1994, but less than flood years like 1996 and 1997.

Q. IS NON-FIRM HYDROELECTRICITY IN BRITISH COLUMBIA RELEVANT TO THE U.S.?

A. Certainly. This is one reason that two important ties – the eastside tie to Spokane and the westside tie to Seattle – were built. British Columbia has a relatively small displacement market of their own. We have corrected Table 12 for their omissions.

Q. WHAT DID AVERAGE WATER IN 2000 REALLY MEAN TO THE WSCC?

A. Higher cost thermal plants that normally would have been displaced were not displaced. The economic impact is that if price had been set by the highest cost running unit, spot prices would have been higher than the year before.

Q. WOULD THIS HAVE BEEN A MASSIVE IMPACT LEADING TO EMERGENCIES AND PRICES HIGH ABOVE THE COST OF HIGHEST COST RUNNING UNIT?

A. No. We have had average water conditions many, many times in the past without seeing the type of market failure we saw in the summer of 2000. In 2001, when hydroelectric generation was quite low, the emergency ended. Indeed, this is reflected in the graph on page 18 of the Hogan/Harvey testimony, which shows that energy demand net of hydro generation in the WSCC was actually climbing steeply in May, June and July of 2001, even as prices were collapsing following FERC intervention in the dysfunctional market in mid-2001. This tracks with the graph, above, which shows that hydro generation in April through July 2001 was far below any other year, even though prices were collapsing at the time on both the spot an forward markets.

Q. WITNESSES HOGAN AND HARVEY (Ex. MSC-65 at 19) ARGUE THAT

ELECTRIC OUTPUT OF HYDRO PLANTS IS THE RELEVANT STATISTIC. IS THAT CORRECT?

A. No. For the reasons explained above, any output above the critical planning year is considered non-firm under the WSCC planning criteria. Further, the drop in hydro output in June 2000 is a perfectly ordinary occurrence as the hydro production from spring runoff in the Rocky Mountains subsides. Things do not become unusual until the 2001 water year, and the Western crisis evaporated in June 2001, just as one would expect the worst effects of the drought to hit as minimal spring runoff has passed through the system and cooling loads in California and the Southwest begin to grow.

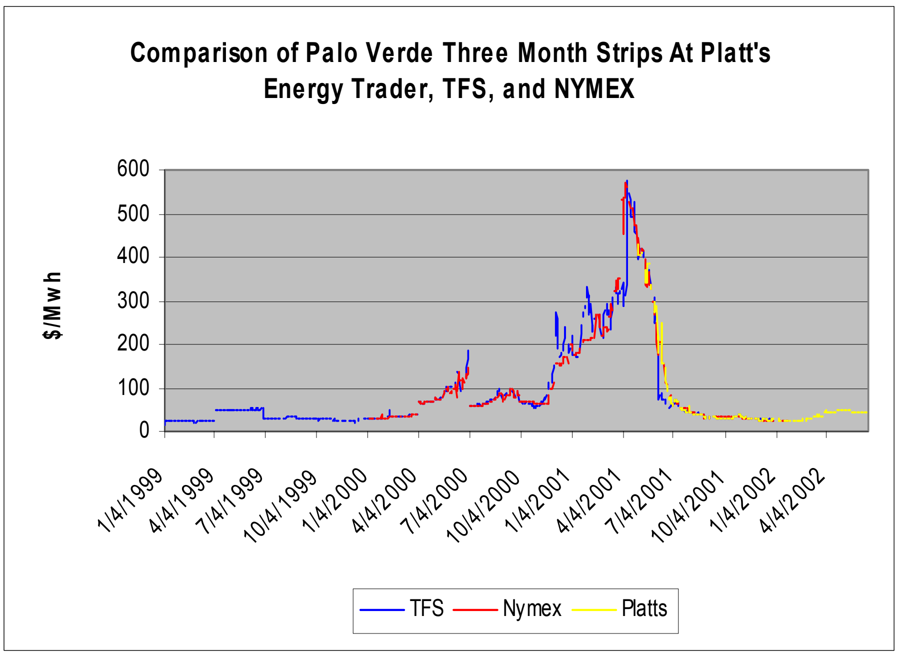
PRICE SERIES

Q. DR. KALT CRITICIZES YOUR USE OF NYMEX AS THE ONLY "OPEN CRY" TRANSPARENT FORWARD MARKET. IS HE CORRECT?

A. I would not agree with him, but I cannot say that any of the price series we have from this period are reassuring.

We did not choose NYMEX lightly. First, until December, NYMEX was a relatively active market. As the crisis wore on, traders withdrew from NYMEX. Activity at NYMEX during the final days of the crisis was nominal at best. Second, NYMEX is an open market where transactions are on an "open cry" basis. This is a far cry from TFS and EnronOnline.

Our analysis of the three series indicates that their overall movements are quite similar:



Q. IS DR. KALT WRONG FOR PREFERRING TFS?

A. Again, the only surprising part of his argument is the vehemence that he brings to it. As he should know, the forward market during this period was opaque. The number of buyers and sellers declined precipitously – so much so that the trading on NYMEX virtually dried up.

NATURAL GAS PRICES

Q. HOW HAVE DRS. HARVEY AND HOGAN CHARACTERIZED THE NATURAL GAS MARKET IN CALIFORNIA?

A. They apparently ascribe the massive increase in California natural gas prices to an increase in demand.

Q. IS THEIR OPINION WIDELY SHARED?

A. No. Curiously, they forgot to mention that the enormous basis differential that arose between California and the rest of the natural gas market is also the subject of investigations, a recent FERC decision concluding that the operator of the major gas pipeline into California had acted improperly, and anti-trust litigation.

Q. ARE DRS. KALT, HARVEY, AND HOGAN SILENT ON ANY OTHER ISSUES PERTAINING TO NATURAL GAS PRICES IN CALIFORNIA?

A. Yes. They did not mention the Initial Report on Company-specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies released on August 2002.[17] The natural gas pricing conclusions of this report are interesting:

- Historically, the spot prices for natural gas at the California delivery points highly correlate with prices at producing basis and Henry Hub. During the months of October 2000 to July 2001 – the refund period in the California refund proceeding – the correlation

[17]Initial Report on Company-specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price

was abnormally low. Since that time, the high correlation has resumed.

- The Commission cannot independently validate the reporting firms' price data, and undetected errors may exist due to a lack of formal verification procedures.
- There are incentives for market participants to manipulate prices reported to the reporting firms, including incentives specific to California due to its regulatory structure.
- Wash trading may have an adverse effect on reported price data.
- EOL was a significant source of price discovery and formation, and was potentially susceptible to price manipulation.

Staff concludes that published California natural gas price data are not sufficiently reliable to be used in the California refund proceeding for purposes of calculating the MMCP and resultant refunds..[18]

Yet these are the same prices relied upon by respondents.

Q. DOES THIS AFFECT THE RESPONDENT'S ANALYSIS?

A. Yes. Respondents' analysis depends on the validity of the very California natural gas

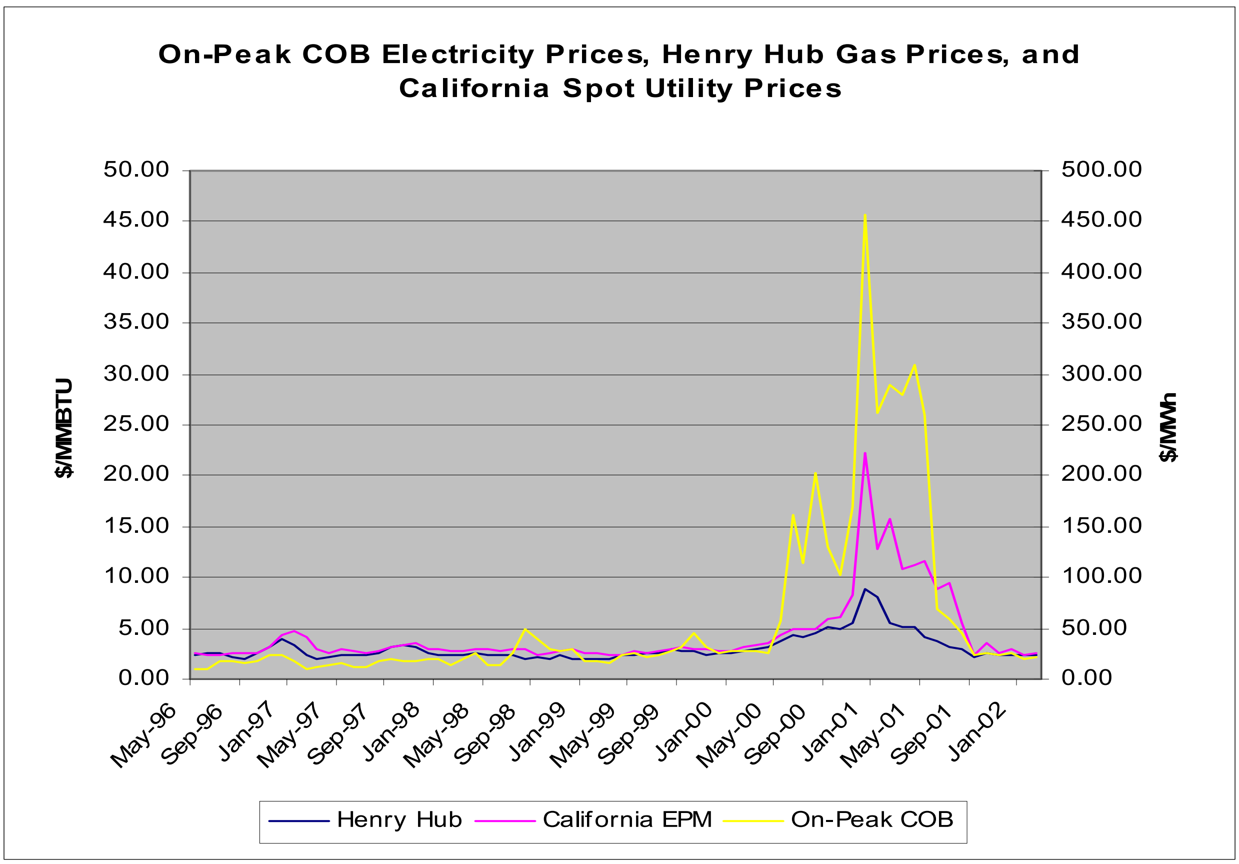
Data; and Enron Trading Strategies, August 2002, FERC Staff

[18]Ibid, page 56.

prices that FERC Staff rejected as unreliable.

Q. PLEASE EXPLAIN.

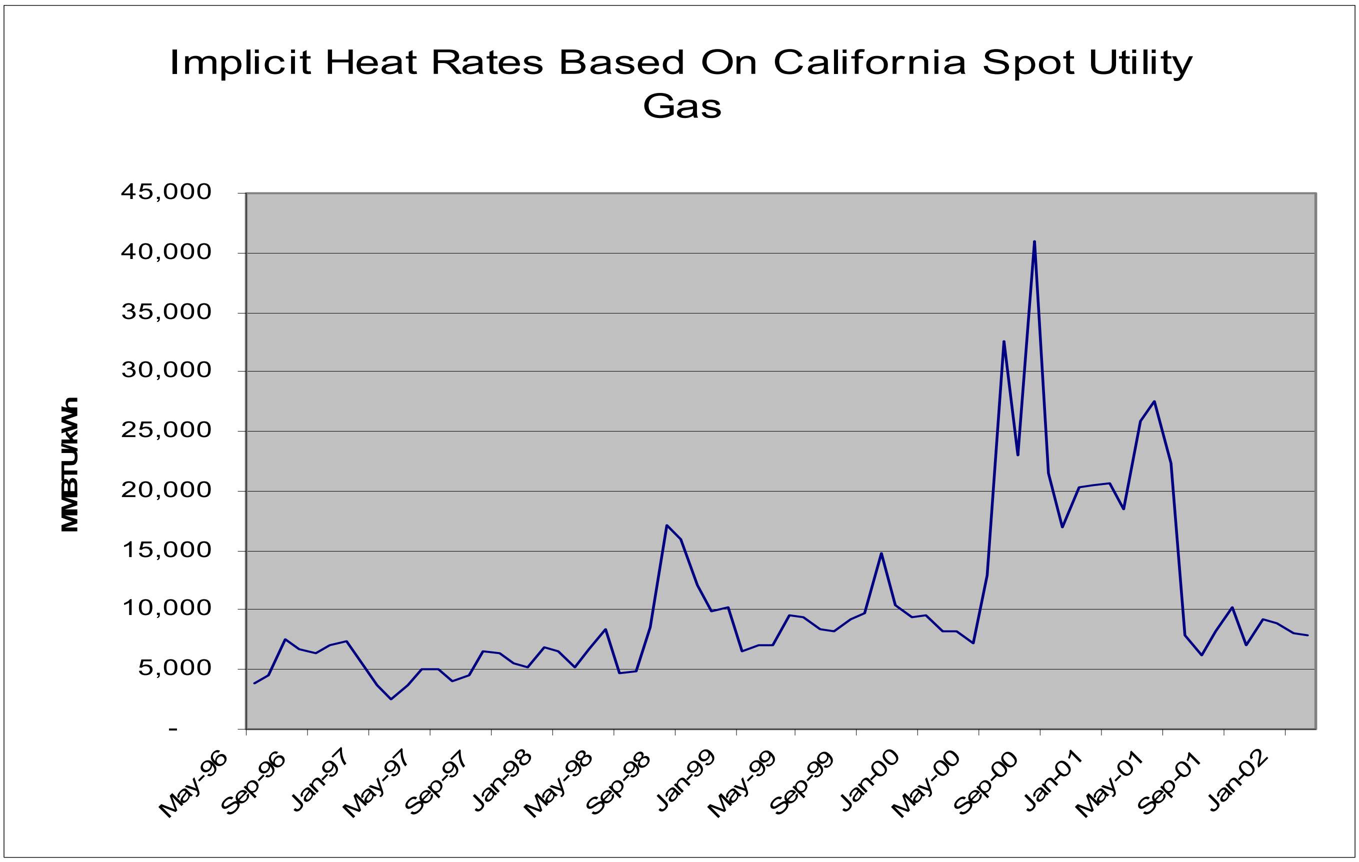
A. There is a marked difference between Henry Hub prices and the California prices relied upon by respondents. The following chart shows the relationship between Henry Hub gas prices, California spot gas prices to utilities from the EMR, and On-peak COB prices.



As amazing as the gas prices were over this period, electric prices increased even more markedly.

Most new gas fired units can operate efficiently at a heat rate of 7,000 – corresponding to the use of 7,000 MMBTU to produce one kilowatt-hour. Older plants, like the steam units owned by Dynegy, Mirant, Duke, AES, and Reliant often operate in the 10,000 to 11,000 range.

We can easily see the implicit heat rates observed during the height of the California market failure, by dividing the on-peak COB price by the California spot gas prices to utilities.



Q. WHAT WAS THE AVERAGE IMPLICIT HEAT RATE OVER THE PERIOD OF THE CALIFORNIA MARKET FAILURE?

A. The average implicit heat rate was 24,213 MMBTU per kilowatt-hour. In August, while gas prices were still low, the heat rate reached 40,910 MMBTU/kWh.

Q. HOW REASONABLE IS THIS?

A. This makes little sense. For natural gas to be the explanation of the crisis, the most expensive plant operating would have had to have had a heat rate of 24,213 on average. Since we know that substantial capacity remained undispatched – even in August – this simply does not make sense.

Q. HOW HAVE FERC STAFF, THE CALIFORNIA ISO, AND OTHER PARTIES DEALT WITH THIS UNLIKELY CASE?

A. The California refund case is likely to order refunds based on a standard plant heat rate. FERC staff has now also recommended the use of a lower natural gas price series in order to avoid the risk of natural gas price manipulations affecting the refund. Respondents attribute this sharp rise in California gas prices to increases in gas demand across the WSCC (Ex. MSC-65 at 27-28), but this explanation makes no sense. As the FERC staff report (Initial Report pages 64 and 65) makes clear, California prices did not track gas prices in the producing regions of the WSCC.

EMISSIONS CREDITS

Q. WHY DO DRS. HARVEY AND HOGAN INCLUDE AN EXTENSIVE DISCUSSION OF THE COST OF NOx CREDITS?

A. On page 35 of their testimony, they state that:

> Because of the reduction in hydro generation output in California and elsewhere in the WSCC, gas-fired generation in Southern California tended to be within or on the margin for meeting load throughout the May 2000-Summer of 2001 period. In periods in which transmission constraints were not binding, electric energy elsewhere in the WSCC could be sold into Southern California to back down this high cost generation, so the variable cost of generating power in Southern California tended to place a floor on electricity prices throughout the WSCC.[19]

Q. IS THIS A REASONABLE ARGUMENT?

---

[19] Ex. MCS-65 at 35-36.

A. As with many parts of their testimony, they rely on broad assertions with little attempt to justify their facts. As elsewhere, some of their facts are correct, some are suppositions, and some are simply incorrect.

Q. CAN YOU GIVE AN EXAMPLE OF A PART OF THEIR PRESENTATION THAT IS CORRECT?

A. Yes. Their broad outline of the RECLAIM program is largely correct, although they tend to ignore the parts of the program that conflict with their argument. RECLAIM did establish a market for NOx credits. It did not establish a market without checks and balances. One feature of the market that they have glossed over is that the market had an automatic review mechanism that took place when the cost of Reclaim Trading Credits (RTCs) went over $7.50. Hence, even if the NOx program inflated spot prices for a time, it should not have had a similar affect on long-term markets since the expectation would have been that the program would be corrected in a short period to reduce the cost of RTCs to $7.50.

Q. CAN YOU IDENTIFY A PART OF THEIR PRESENTATION THAT IS PURELY HYPOTHETICAL?

A. Drs. Harvey and Hogan have simply assumed a value for the relationship between kilowatt-hours and NOx. While the value isn't extreme, it misses much of the behavior of the generators during this period. For example, in some cases, the generators adopted operating changes that reduced their NOx emissions by a factor of 5 to 10. While they assume NOx rates in the 4 to 5 pounds per kilowatt-hour, a careful review of the EPA filings by the generators indicate that average rates are far lower**.**

Q. HAVE YOU REVIEWED THE DISCUSSION OF PRICING RTCS IN THE TESTIMONY OF DRS. HOGAN AND HARVEY?

A. Yes. While many points made by Drs. Hogan and Harvey are pertinent, their testimony on this point shows the difficulties of making the facts fit their theory. The basic problem they face is that everyone's expected price of RTCs fell at the end of January.

While Drs. Harvey and Hogan gloss over the problem of finding RTC prices, the fact is that RTCs are among the most opaque of the pricing elements of the very opaque California market. Their approach was to ask one of the market participants for their own pricing series. In a sense, this is like asking a criminal to provide his own alibi at trial.

Our approach, by contrast, is to use the information available from the RECLAIM market itself.

Q. WOULD PARTICIPANTS IN THE RTC MARKET KNOW THAT PRICES MIGHT FALL?

A. Yes. One of the bylaws of the Reclaim market (Rule 2015 Backstop Provisions) was that when prices for RTCs reached $7.50/lb the board would meet to determine whether the goals of the program were being met. The language from the bylaws states:

> Should the average RTC price be determined, pursuant to Rule 2015 (b)(1)(E), to have exceeded $15,000 per ton, equivalent

> to $7.50/lb within six months of the determination thereof, the Executive Officer shall submit to the Air Resources Board and the Environmental Protection Agency the results of an evaluation and review of the compliance and enforcement aspects of the RECLAIM program, including the deterrent effect of Rule 2004 paragraphs (d)(1) through (d)(4).

It further goes on to state the objectives of this evaluation:

> The Executive Officer shall submit, with the results of the evaluation, either a recommendation that paragraphs (d)(1) through (d)(4) be continued without change, or amendments to the RECLAIM rules setting forth revisions to paragraphs (d)(1) through (d)(4) of Rule 2004

Rules 2004 (d)(1) through (d)(4) sets forth the prohibition of emissions in excess of the annual allocation.

Q. WHY DID THE RTCS FALL IN JANUARY?

A. On January 19, 2001, the SCAQMD staff presented the solutions that formed the basis for Rule 2020. As Drs. Hogan and Harvey noted, there was a contingent risk at this point that the rule might not be passed or that the NOx allowances might be assessed against future allotments. The point that they did not make is that such risks were very, very small. Any participant in the California market knew that Governor Davis – and the SCAQMD board – were very interested in maintaining generation in the L.A. basin. In fact, they were concerned enough that SCAQMD had appointed an advisory group in November 2000 to look into ways of managing the rising costs of RTCs. The odds that they would take steps that would forestall that were very low.

The appropriate language from the draft rule is found in Chapter 5, "The Near-Term and Long-Term Options to Stabilize NOx RTC prices:

-Implement Emergency RTC Price Caps

> Proposal to establish a temporary upper price limit to immediately cap the rise in the RTC price. An upper price cap not only prevents unreasonable escalation in prices, but also minimizes the instances of "panic purchasing"

Industry knowledge of the proposed changes to the emissions credit rules was likely well known. Among the members of the advisory committee that helped to create the "White paper on Stabilization of Nox RTC Prices" were representatives of, Sempra Energy, Southern California Edison, Enron Energy Services, Mountainview Power, and NRG Power Marketing. This advisory group had been meeting numerous times to develop and recommend changes to RTC policies since November of 2000.

Q. WERE THERE EXECUTIVE ORDERS FROM GOVERNOR DAVIS BEFORE THE ONE MENTIONED BY DRS. HOGAN AND HARVEY?

A. Yes. Governor Davis issued two orders, the first on January 17, 2001 and the second on March 7, 2001, that directed air quality agencies to provide support for continued generation.

Executive Order D-24-01, dated January 17, 2001, provides: "It is ordered that local air pollution and air quality management districts shall modify emissions limits that limit the hours of operation in air quality permits to ensure that power generation facilities that provide power under contract to the Department of Water resources are not restricted in their ability to operate.[20]

The executive order also went on to add a potential 50% reduction in market price of RTC's for generators:

> Such credits shall be provided to such facilities at up to the market rate for emissions reduction credits. In the case of a powerplant that agrees to sell its power under contract to the Department of Water Resources, the State of California will make available where necessary and available the required emissions credits at up to a 50 percent reduction.[21]

The second executive order D-28-01 from Governor Davis, released on March 7, 2001, instructed:

> The authority provided to local air pollution control and air quality management districts and the air resources board in the first ordering paragraph of Executive Order D-24-01 shall also apply to any power generating facility, including any previously permitted existing power generating facility that is not currently operating, as necessary to ensure reliability of the grid and delivery of power in the State.[22]

Q. WHY IS THIS A PROBLEM FOR DRS. HOGAN AND HARVEY'S THEORY?

A. Spot prices continued to climb until April. If RTCs were the cause, as Drs. Hogan and

[20] Executive Order D-24-01 by the Governor of the State of California January 17, 2001
[21] Id.
[22] Executive Order D-28-01 by the Governor of the State of California March 7, 2001

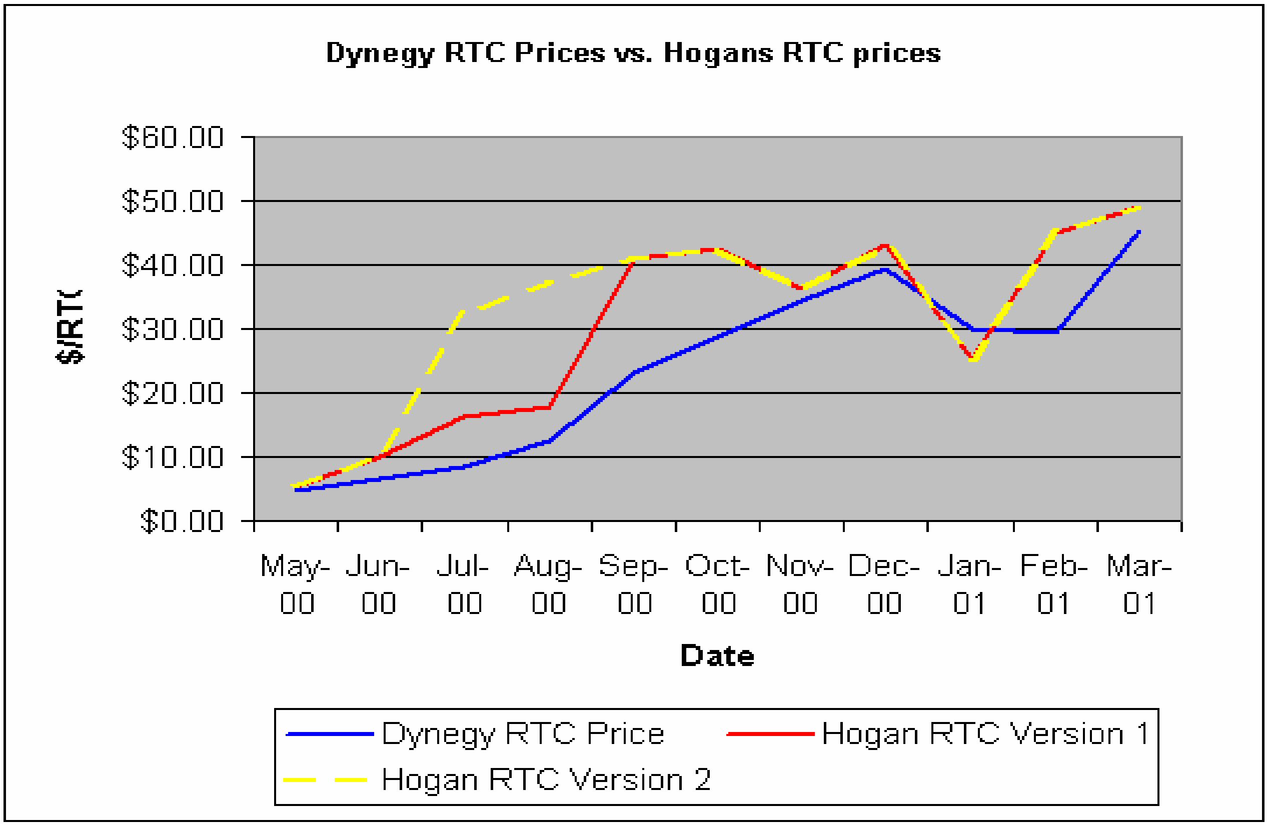
Harvey contend, they were having a small difficulty with the direction of change. If the price of RTCs had fallen, spot prices would have fallen as well. Unfortunately, for Drs. Hogan and Harvey, spot prices continued to climb.

Q. IS THIS ALSO A PROBLEM FOR THEIR THEORY OF FORWARD PRICES?

A. Clearly. They have to assume that no market participants figured out that the rules were going to change. In fact, given the pressures on California to free up generation amidst the growing crisis, it was clear that the $7.50/lb rule was very likely to be adopted. In practice, Dynegy simply stopped buying RTCs in the market in March.

Q. HOW WELL DO THE DYNEGY RTC PRICES MATCH THE PUBLISHED MARKET FIGURES?

A. Rather poorly. The following chart shows actual market data compared to the Dynegy price series they have proposed:



Actual Dynegy prices appear to be significantly less than the series Drs. Harvey and Hogan have brought to the table.

Q. IS THERE ANY WAY TO BE CERTAIN WHAT RTC PRICES WERE AT ANY GIVEN TIME?

A. To be fair, there isn't. Price discovery is the exception, rather than the rule. Transfers of RTCs are often accompanied by zero price – a difficult to interpret pricing point. Actual use of the RTCs can occur at any time over the cycle period, so ascribing specific monthly values to specific electric generation is very, very difficult. NOx use per kilowatt-hour can change dramatically, even over a matter of days. Most importantly, enforcement is lax and the arrangements are open to continuous renegotiation.

Q. TO LISTEN TO DRS. HARVEY AND HOGAN, RTCS ARE THE CRITICAL PRICING POINT IN THE ENTIRE MARKET FAILURE. IS THIS REASONABLE?

A. No. If the NOx emissions were that important, the plants in the Los Angeles basin would have been in continuous search for environmental improvements and optimization. Instead, a number of the plant owners engaged in a languorous negotiation with the SCAQMD for changes in the rules. Overall, even at the height of the RTC market, this factor would only have added $50 to the marginal operating cost.

Q. DRS. HARVEY AND HOGAN GO ON TO LIST ADDITIONAL OPERATING CONSTRAINTS (EX. MSC-65 AT 36-37). HOW SIGNIFICANT ARE THESE?

A. In practice, the environmental agencies did their best to support plant operations during this critical period. The other cases they cite are minor, to say the least. Dynegy's Cabrillo 1 unit was exposed to a $7.75 charge. This is effectively the same low rate adopted by SCAQMD in January. The $100,000 charge for a variance at the end of 2000 for Duke's South Bay unit seems large until it is compared with the prices that Duke was receiving for power in January. Given their sale at $4,300 per megawatt hour, a single 25 MW sale for one hour could have recovered the entire amount.

The restrictions cited for the South Bay unit applied on an annual basis without specific hourly restrictions. When we checked the surprising reduction in output at South Bay on January 17, 2001, in response to the testimony of Duke whistle blowers at the California Senate Committee on Price Manipulation, we discovered that Duke had reduced its output at unit 3 even though it was in the midst of a Stage 3 Emergency.

Q. WHAT DID THE ENFORCEMENT OFFICIALS AT THE SAN DIEGO AIR QUALITY DISTRICT SAY ABOUT THIS DECISION?

A. They were quite surprised since they do not take enforcement actions on an hourly basis.

CALIFORNIA NUCLEAR UNITS

Q. **HOGAN AND HARVEY (EX. MSC-65 AT 39) CITE REDUCED PRODUCTION FROM CALIFORNIA NUCLEAR UNITS AS A CAUSE OF THE CRISIS. IS THIS PLAUSIBLE.**

A. No. To begin with, an examination of the data on Table 27 of the Hogan/Harvey testimony reveals that, for most months of the crisis, nuclear output was well within the range of normal operations . Even in the months cited as having unusually low output, January through April of 2001, the table reveals that output for each of these months in 1999 or 1998 or both was actually lower. Further, the only month in which nuclear output was substantially below any of the previous three years, May, prices had started to decline.

Q. DOES THE ARGUMENT HAVE SIMILAR PROBLEMS ELSEWHERE?

A. Yes. Hogan and Harvey's Table 28 shows that the energy demand net of hydro and nuclear generation was actually higher than or near the levels of the previous year from

May through December 2001, even though prices fell dramatically during this period, then remained at historically low levels. Again, this points up the difficulty of explaining away the crisis by pointing to market fundamentals.

Q. DOES THE QUESTION OF CANADIAN IMPORTS (Ex. MSC-65 at 40-42) SUFFER FROM THE SAME PROBLEM?

A. Yes. As Table 30 demonstrates, imports from Canada dropped precipitously in mid-2001, probably as a consequence of the drought, even as prices were dropping across the WSCC.

QF Supply, Credit Risk, and DWR Purchases

Q. HOGAN AND HARVEY (Ex. MSC-65 at 43-46) ARGUE THAT CALIFORNIA'S INABILITY TO PAY ITS "QF" GENERATORS WAS A "MARKET FUNDAMENTAL." IS THIS A FAIR CHARACTERIZATION?

A. No. Clearly, the inability of California utilities to pay for the output from QF generators, to the extent it contributed to the crisis, was caused by another set of faulty rules governing the California market, not by anything that can properly be characterized as a "market fundamental." In short, these were ill-conceived regulations that artificially constrained supply and drove up prices; however, they do not amount to what would ordinarily be considered a market fundamental such as high generation costs.

Q. HOGAN AND HARVEY (Ex. MSC-65 at 46-50) LIKEWISE ARGUE THAT SUPPLY WAS CONSTRAINED BECAUSE OF THE LACK OF CREDITWORTHINESS OF CALIFORNIA'S MAJOR UTILITIES. IS THIS CORRECT?

A. As Hogan and Harvey acknowledge, this was "[a]n important element of dysfunction in the spot markets," not a market fundamental. This is another example of foolishly designed market rules in California, which forced the major IOUs into the impossible position of paying more for wholesale power than they could charge in retail rates. This led to a huge disruption in the power supply scheme and California's crash program to establish a state-run power purchasing agency, while at the same time trying to conform to the requirement in FERC's December 15, 2000 order requiring an extremely large volume of load to be moved from the spot to the forward markets. Poorly designed market rules produced prices that were far out of line with what would be produced in a workably competitive market, not, as Hogan and Harvey would have it, a "market fundamental."

GAMING AND PRICES

Q. HOGAN AND HARVEY (EX. MSC-65 AT 54-64) STATE REPEATEDLY THAT YOU DID NOT EXPLAIN HOW THE ENRON TRADING SCHEMES COULD AFFECT PRICES. IS THIS CORRECT AS A FACTUAL MATTER?

A. No. My testimony made clear how each of these schemes could affect spot prices.

Q. WERE YOU ABLE TO QUANTIFY THESE IMPACTS AT THIS TIME?

A. Yes, although not directly. The model reproduced on pages 92-93 of EX. SNO-17 shows that portion of California prices that was driven by fundamentals at the time and demonstrates that prices were far above what could be justified by those fundamentals. At least part of the excess can be attributable to the trading schemes pioneered by Enron

Q. HOGAN AND HARVEY (Ex. MSC-65 at 55, 57) SUGGEST THAT CERTAIN ENRON SCHEMES HAD A POTENTIALLY POSITIVE EFFECT ON THE MARKET. IS THAT CORRECT?

A. No. The recent FERC Staff report firmly rejected the assertion that the Enron schemes were a legitimate form of arbitrage. Staff's review of the evidence indicates that Enron, as a corporate entity, displayed great eagerness to experiment with all aspects of market rules and protocols in an effort to "game the system" or to simply provide false information. Enron's corporate culture, which permeated all of its affiliated companies, including those affiliates such as Portland which are not currently in bankruptcy, fostered a callous disregard for the American energy customer and demonstrates the need for more explicit prohibitions a as well as aggressive market monitoring and enforcement.

In a market environment, one expects that traders, working within Commission approved market rules, will utilize various strategies in an effort to maximize profits. But a fundamental aspect of some of the Enron trading strategies is the deliberate use of false information. A market cannot operate properly without accurate information. Implicit in Commission orders granting market-based rates is a presumption that the power marketer's behavior will not involve fraud or deception.[23]

Q. CAN YOU GIVE AN EXAMPLE?

[23] Initial Report on Company-specific separate Proceedings and Generic Reevaluation; Published Natural Gas Price Data; and Enron Trading Strategies Fact-finding Investigation of Potential manipulation of Electric and Natural Gas Prices in PA-02-2, issued August 13, 2002 FERC, p. 78

A. Yes. The first scheme Hogan and Harvey address (Ex. MSC-65 at 55-56) is "Fat Boy." "Fat Boy" is a simple scheme to file a false schedule for a larger load in the California market than will actually materialize. The surplus over the load is automatically entered into the ISO's real time market and receives the Ex Post price.

Q. DOES THE ISO APPROVE OF THIS PRACTICE?

A. Most emphatically not. The presence of uninstructed deviation is a costly practice at best and a dangerous practice at worst.

The practice generally leaves real time operators with unscheduled energy. This energy may or may not reflect a good economic choice because it arrives on the system without warning. In many cases this will force the operators to ramp down units that had been scheduled to operate. To the degree that frequent ramping adds to fuel costs and emissions, this is a problem for society as a whole.

Q. IS THIS THE ONLY PROBLEM WITH FAT BOY?

A. No. The loads fraudulently entered into the scheduling process are not the same as real loads. Enron was proposing to inflate apparent loads on the ISO system. The defense Enron gave was that other parties were fraudulently underestimating loads. Now that the PX is gone, this practice is posing real operating costs for the California ISO.

There is a deeper problem with this practice, however. As discussed above, California emergencies were not caused by an actual comparison between capacity and load. Until the April 26, 2001 order, generators could, and did, simply not bid into the ISO's reserve markets. When this happened, the ISO was faced with a scheduled insufficiency and would be forced to call an emergency. In practice, this forced the ISO into emergency purchasing.

Fat Boy rewarded generators to remove their generation from the scheduled market and place it in the real time market. This poses a real economic loss to society since the schedulers were unable to plan for the daily dispatch to meet load.

To use an everyday simile, this is the equivalent of the local grocery store opening its doors with empty shelves, but offering, on a real time basis, to find groceries for customers if they are getting hungry. In the real world, we would avoid returning to this store. Unfortunately, in California, the ISO was the only option consumers had.

In economic terminology, Enron's ability to affect the condition of the California ISO allowed them to become at least a discriminating oligopolist. Given the poor generation record of its competitors in the market, it may well have become a discriminating monopolist. In either case, Enron had developed a set of techniques to sell their products in a very special market – emergency sales to the ISO.

Q. WAS FAT BOY TIED TO OTHER ABUSES?

A. Yes. Once a trader was in possession of a fraudulent load, it became very advantageous to schedule energy to that load over a congested transmission path. The trader then can file adjustment bids. If the ISO accepts their adjustment bid, they can make a profit for not carrying power to the imaginary customer. If the ISO does not accept their adjustment bid, they simple sell into the Ex Post market.

Q. DO WE HAVE ANY EVIDENCE THAT THIS ACTUALLY TOOK PLACE?

A. Yes. A number of the affidavits filed in Docket No. PA02-2 described such arrangements. Tim Belden, Enron's west coast trading manager, sent an interesting email to Terry Winter and Kellan Fluckiger after the onset of the market failure complaining that the emergency purchases the ISO had made from Enron had lowered his revenues in the Ex Post market:

> I just finished talking with Zora about the Out of Market activities yesterday and thought that it would be a good idea to put my thoughts into an e-mail . It appears as though the MW that you procure out of market end up suppressing the ex post price. For example, Enron sold the ISO 100 MW for $750/MWh during hours 17, 18, and 19. It was our impression that the ISO was procuring large volumes of energy out of market during these hours . Yet the ex post price for these hours settled at $379.29, $300.00, and $119.77 respectively. Every MW that you purchase out of market reduces the number of MW that must be procured through the BEEP stack. Reducing the number of MW procured through the BEEP stack naturally puts downward pressure on the ten-minute and ex post price. Yesterday's prices support this theory. We saw this happen in the summer of 1998 as well .

> The result is that you harm providers of energy in-state. This could be instructed or un-instructed deviations. Yesterday we had nearly 800 MW of uninstructed generation in the state (in the form of over-scheduled load). Your out of market calls, coupled with the way that you perform ex post pricing, hurt us and everyone else who provided energy within the state to you in real time.[24]

The amazing thing about this email is both the scale – 800 MW had been taken out of the prescheduled markets and its cheek. The 800 MW, if scheduled into the PX or the ISO markets, would have made a significant contribution (approximately 30% of all required reserves on that day) to avoiding the first emergency declaration of the California market failure. The cheek, complaining that the ISO had not paid enough in the course of an emergency that Enron had contributed to, is an example of the same hubris that eventually brought Enron into bankruptcy.

Q. Drs. Harvey and Hogan apparently doubt that this raised prices on May 22, 2000. Are they correct?

A. Clearly not. May prices for this period had been running in the $40/MWh range. Prices on the 22nd went to $76 and prices on the 23rd went to $177.50.

Q. WAS THIS THE FIRST TIME ENRON HAD RAISED PRICES IN THIS WAY?

A. Clearly not. The Silver Peak incident was a "proof of concept" for this type of maneuver. Both Fat Boy and "Elephant through the needle," Tim Belden's description of Silver Peak, removed generation from the knowledge of the ISO. Once the ISO was forced into

---

[24] Tim Belden email to Terry Winter, Zora Lazic, and Kellan Fluckiger, May 23, 2000.

emergency purchases, Enron could sell the same energy back to them at a much higher price.

Q. WHAT WAS THE PRICE IMPACT OF SILVER PEAK?

A. The California PX estimated that it had raised prices 71% that day.

Q. DRS. HARVEY AND HOGAN GO THROUGH EACH OF THE SCHEMES AND STATE IN EACH CASE THAT YOU HAVE NOT DESCRIBED THE IMPACTS ON COST. IS THIS CORRECT?

A. No.

Q. HOW DID THE ENRON SCHEMES RAISE PRICES?

A. Each of the Enron schemes had slightly different mechanics. Some of the schemes were designed to fraudulently receive congestion fees from the ISO. The constrained PX prices reflected these predations. Schemes designed to remove power from the knowledge of the ISO until it could be repurchased on an emergency basis simply created artificial shortages. Schemes like Silver Peak and Deathstar that could be used to disrupt schedules and force the ISO into emergencies both raised costs and brought the system closer to failure.

Q. DID THESE SCHEMES DIRECTLY RAISE LONG TERM PRICES?

A. Of course not. California had very little involvement in the forward market. Regulatory rules discouraged utilities from participation in the Block Forward Market or NYMEX. Creating schemes to disrupt markets that were not significant would have been a waste of time.

Q. HOW DID THESE SCHEMES RAISE LONG TERM PRICES?

A. In the simplest possible way. Traders could not sell long term power at prices less than they could expect to see in the spot market. If they had, they would have been working against their own self interest. The secrecy at the ISO and the sheer complexity of the California market made it impossible for anyone but a perpetrator of the schemes to know what was going on. Any trader who told his management that he planned to sell below the observed level of spot prices during the period of the crisis would have been fired on the spot.

Q. DRS. KALT, HARVEY, AND HOGAN REPEAT MANY TIMES THAT THE MARKET KNEW BETTER – THAT LONG TERM PRICES ARE SET BY ENTIRELY DIFFERENT FUNDAMENTAL FORCES THAN SPOT MARKETS. IS THIS CORRECT?

A. No. Their theories have gotten in front of their economics in this case. While they believe that such models apparently existed, they have not brought them to this hearing. To the contrary, we have no evidence at all that would explain why a trader would take a loss against expected spot prices in order to follow a fundamentals forecast. First, none of the fundamentals forecasts – even Enron's – predicted or explained this crisis. Second, most market participants believed that the crisis would last two to four years – Belden's often repeated refrain. If so, selling at less than observed spot prices would have been very foolish.

Respondents have one major problem with their case. The fundamentals affecting long term prices were known significantly before the collapse of long term prices. Load resource balance, new plant construction, regulatory changes, hydroelectric supply, and environmental rules were all known before the prices collapsed. The one event that did take place simultaneously with the collapse of long term prices was the collapse of short term prices. The causation was simply the realization that the crisis was not going to last two to four years into the future and long term prices were again going to be governed by economic theory.

Q. THE RELATIONSHIP BETWEEN SPOT AND FORWARD PRICES DURING THIS PERIOD WAS SIMPLY OPPORTUNITY COST. IS THIS CORRECT?

A. Yes. While theories are excellent, the reality is that traders had to live in the real world. If they could have explained the market environment, they certainly would have. In the absence of a solid explanation for the prices they were observing, they had to make sure that their long term prices were at least as high as the money they could make selling into the spot markets.

Q. DRS. KALT, HARVEY, AND HOGAN KEEP REPEATING THE LITANY THAT THESE SCHEMES WERE NOT THE FAULT OF THEIR CLIENTS. IS THIS TRUE?

A. We don't know, nor is it very relevant to the question whether the rates charged to Sierra Pacific and Snohomish PUD were just and reasonable. El Paso Gas is under investigation for their role in gas prices. Some of the other respondents have been identified as possible participants in the market schemes, and public record admissions implicate a number of the respondents in this case. Regardless of whether these accusations prove out or not, the fact is that, partly as a result of market manipulations such as the Enron-style schemes, the prices in the market were not just and reasonable.

ECONOMIC WITHHOLDING IN CALIFORNIA

Q. **DID DRS. HARVEY AND HOGAN HAVE ANY OTHER CRITICISMS OF THE MARKET POWER REGRESSION?**

A. Yes. They have a page long criticism of the hydroelectricity data used in the regression on page 92:

> Mr. McCullough's model includes a variable described in the spreadsheet as "EIA- Electric Power Monthly actual hydro." Rather than being a variable reflecting Western hydro generation, however, this variable appears to be based on total hydro generation in the United States. Thus, Mr. McCullough's model in effect uses variations in the hydro output of TVA, Niagara Falls and the St Lawrence project to predict Mid Columbia prices. Since the output of Eastern hydra generation did not decline as much as did Western hydro generation during this period, this error in variables would tend to cause the model to under predict Western electricity prices during the period of reduced hydro generation. Second, it appears that Mr. McCullough has not correctly matched the hydro output reported in Electric Power Monthly with the price data. It appears that Mr. McCullough has matched the data from a given issue of Electric Power Monthly with electricity prices for that month, despite the fact that because of publication lags, the hydra generation data actually applies to a period 3 months earlier. Thus, it appears that the hydra generation used by Mr. McCullough for June 2000 is actually the data for March 2000 etc. Third, the use of data on U.S. hydra generation does not control for changes in Canadian hydro generation or imports . Fourth, the hydro generation variable was not adjusted for the varying number of hours in

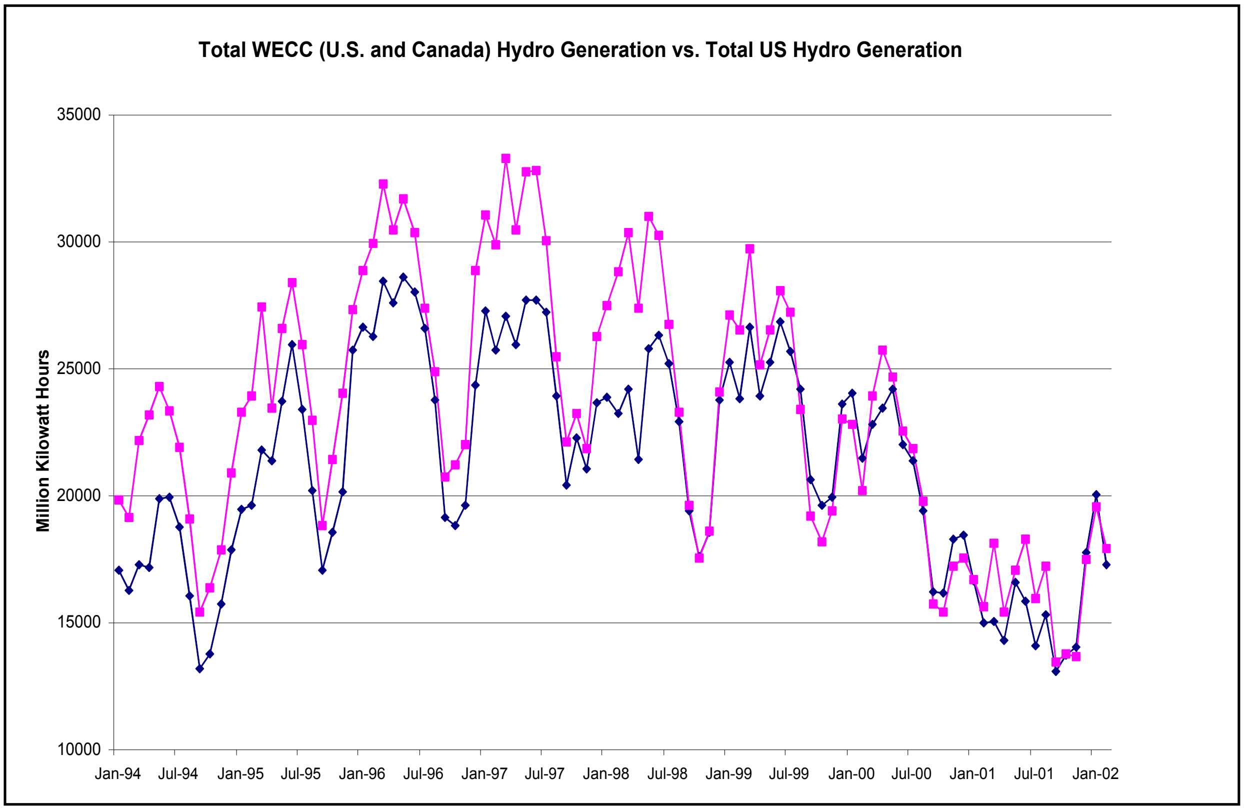
the month.[25]

Q. IS ANY OF THIS CORRECT?

A. No. This entire page of criticism was completely baseless. We used data for the output of generation from the Western United States and BC and Alberta Canada, not from the entire United States.

Q. WOULD THE DATA MATCH A THREE MONTH LAGGED VALUE FOR THE ENTIRE U.S.?

[25] EX. MSC-65 at 92.



A. No. This is an entirely different series of numbers.

It is virtually impossible to mistake one series for the other. Moreover, the three month lag mentioned by Drs. Harvey and Hogan seems completely absent.

Q. IS THERE ANY IRONY TO THIS COMPLETELY UNJUSTIFIED CHARGE?

A. Yes. They left Canadian generation out of their own description of hydroelectric generation on page 16 of their responsive testimony as well as their "structural model."

Q. IS THIS THE ONLY CRITICISM OF THIS MODEL?

A. No. They have a variety of additional complaints.

Q. WHAT WEIGHT SHOULD BE GIVEN TO THESE CRITICISMS?

A. Very little. While one of their criticisms has merit – a numerical error transcribing reserve margins – this has virtually no impact on the results of the simple regression.

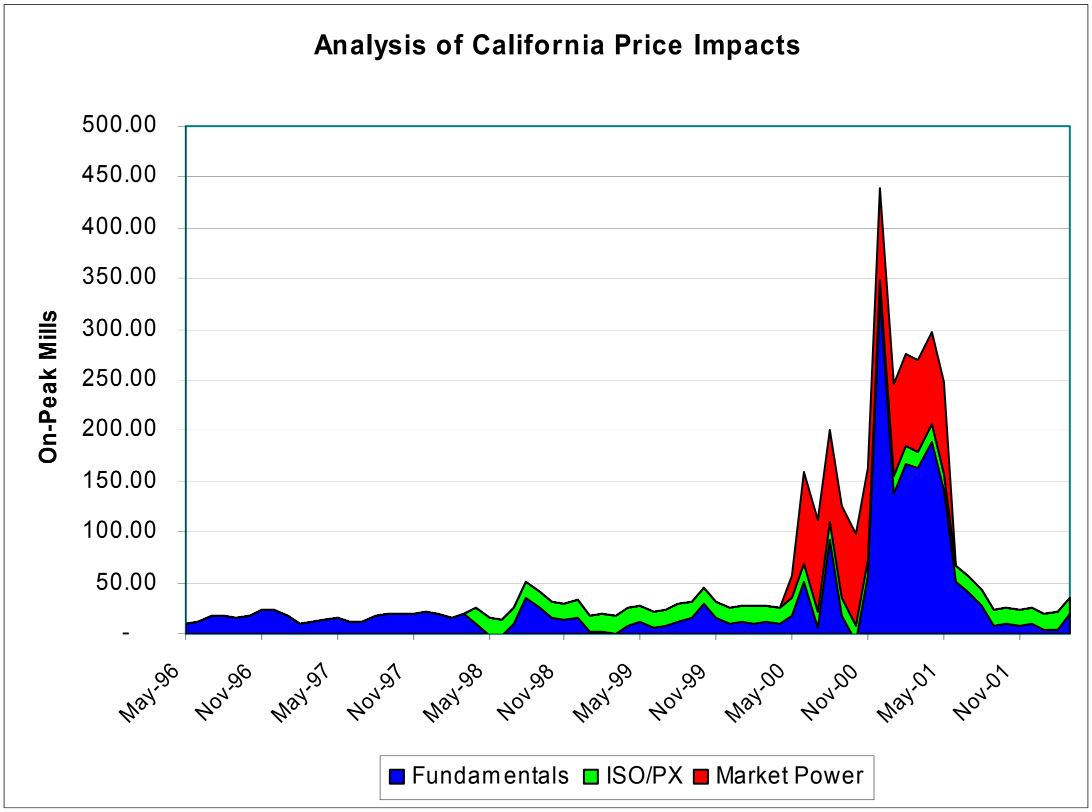
Q. HAVE YOU RE-ESTIMATED THE MODEL CORRECTING THE TRANSCRIPTION ERROR?

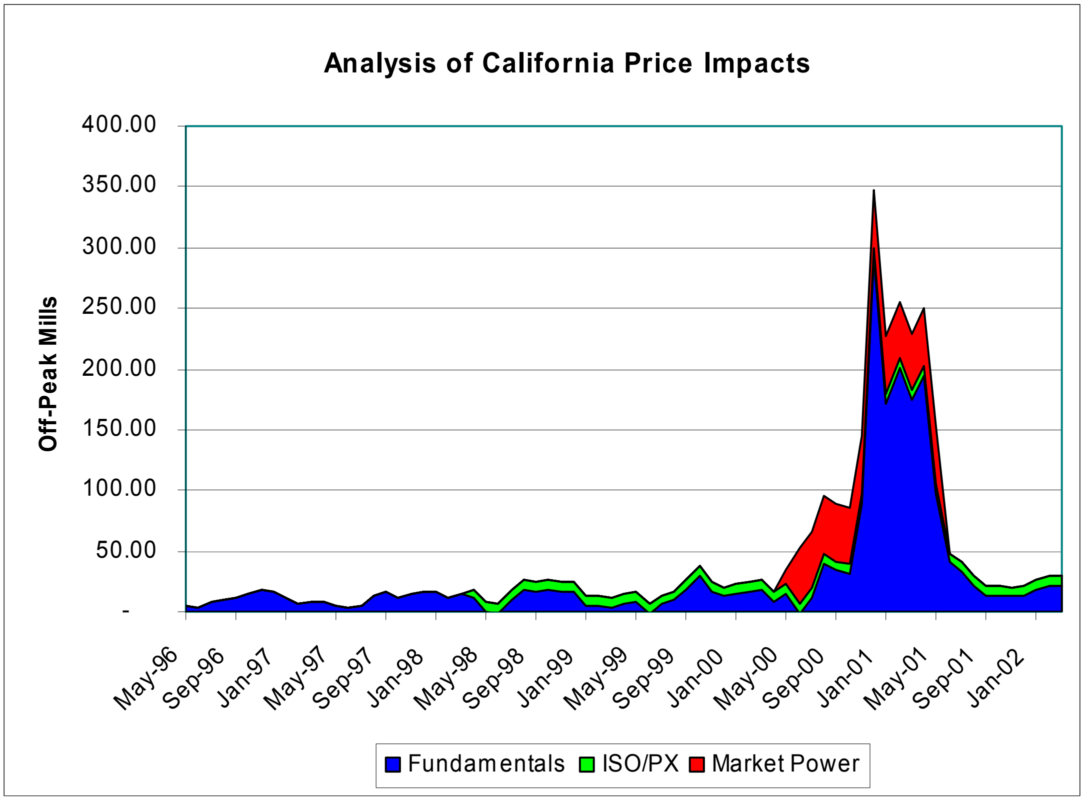
A. Yes. The results are virtually unchanged.

Q. WHAT ARE THE RESULTS?

A. On-peak prices were $90.93/MWh higher than can be explained by hydroelectric generation, gas prices, and reserve margin during the period of the market failure. Off-peak prices were $46.73/MWh higher than can be explained by the same variables during the market failure period.

The following two charts show the relevant contributions of fundamentals – gas, hydro, and reserve margin, the presence of the California market structure, and market power.


Analysis of California Price Impacts
On-Peak Mills
500.00
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
-
May-96
Nov-96
May-97
Nov-97
May-98
Nov-98
May-99
Nov-99
May-00
Nov-00
May-01
Nov-01
Fundamentals
ISO/PX
Market Power



Q. DRS. HARVEY AND HOGAN CRITICIZE YOUR MODEL FOR USING HENRY HUB GAS PRICES RATHER THAN CALIFORNIA'S CITY GATE PRICES. IS THERE ANY MERIT IN THEIR ARGUMENT?

A. No. As discussed above, FERC staff have recommended using natural gas prices from outside of California to avoid the surprising change in basis that was reported over this period.

The important issue here is to measure the degree of market power that occurred during this period. Since the gas series they use is doubtful at best, and manipulated at worst, they are simply recommending the assumption that these gas prices were driven by competitive forces and correctly reported.

Q. DRS. HARVEY, HOGAN, AND KALT ALSO CRITICIZE THE SIMPLICITY OF THE MODEL AND THE USE OF A DUMMY VARIABLE TO MEASURE THE DEVIATION FROM FUNDAMENTALS. IS SIMPLICITY A BAD THING IN MODEL MAKING?

A. No. Anyone who reviews their testimony will notice that the model addresses the basic factors they have raised. A good model is driven by a clear *a priori* structure. The alternative, searching for explanatory variables that given the results that the researcher is seeking is profoundly misleading.

The use of a dummy variable simply reflects the fact that hydro generation, reserve margin, and natural gas prices do not match the observed electric prices over the May 22, 2000 through July 3, 2001 period. The timing of the dummy is set by the months of the California market failure.

Q. DRS. HARVEY AND HOGAN PROPOSE A COMPETING MODEL. DOES THIS HAVE A SIMPLE *A PRIORI* STRUCTURE?

A. No. The nature of linear regression is that if you try enough variables you can eventually find a regression with good statistical properties. This high tech version of darts is commonly referred to as data dredging.

Statistical tests indicate how likely a specific result would be the result of pure chance.

Significance at the 99% level means that only one regression in one hundred could be expected to be the result of pure chance variation in the data.

The difficulty with data dredging is that with modern computers, any sufficiently motivated researchers can run one hundred regressions and then only report the one that matches their objectives.

Q. IS THERE ANY EVIDENCE THAT DRS. HARVEY AND HOGAN HAVE FALLEN INTO THIS TRAP?

A. Based on their selection of variables, I suspect that they worked to find regression results they liked. For example, one variable they used in their regression was the square of the inverse of WSCC reserve margins.

Q. IS THIS VARIABLE COMMONLY DISCUSSED IN RELIABILITY PLANNING OR POWER COST ESTIMATION?

A. No. This variable is equal to actual loads times actual loads divided by capacity after outages time capacity after outages. This is a variable that would never normally come up in any normal utility analysis. The apparent logic might be to try to approximate WSCC dispatch curves with a second order polynomial.

Q. THEY ALSO USE THE VARIABLE "RECLAIM NOX PRICES (CYCLE 2) TIMES NET DEMAND." IS THIS UNUSUAL?

A. Yes. Again, this isn't used anywhere in the industry. Moreover, it isn't even very clear why a doubtful series of NOx prices would ever be multiplied by customer demand.

Arguably this is the total cost if each customer wanted to purchase a pound of NOx for each MWh they consume. In fact, this variable's only role is to artificially inflate the statistical properties of their regression.

In introductory physics classes we are taught to enter all of the units in the equation in order to check the rationality of the result. This variable is interesting enough that we actually tried to understand what the coefficient would mean. According to Drs. Harvey and Hogan, \$/kWh is related to kWh*\$/NOx lb. The coefficient, therefore would seem to be in units of Pounds/kWh^2.

Q. DO WE KNOW HOW MANY DIFFERENT REGRESSIONS THEY TRIED BEFORE THEY CAME UP WITH THESE OUTRE EXPLANATORY VARIABLES?

A. No, but it appears likely that many, many alternatives were tried before they tried multiplying NOx prices times customer demand.

Q. IS THERE ANY VALUE TO THEIR DEMONSTRATION?

A. No. This is data dredging at its most obvious.

Q. HOW MUCH DATA DREDGING DID YOU UNDERTAKE?

A. None. We have been using this simple model since the beginning of the market failure. We specifically have not searched for variables that would "pump" our results in order to avoid the ethical questions such data dredging raises.

SIMPLE ECONOMIC DISPATCH MODEL

Q. RESPONDENTS HAVE CRITICIZED YOUR MODEL THAT FORECASTS OPTIMAL GENERATION DISPATCH BASED ON ELECTRIC PRICES, FUEL COSTS, AND YOUR PRICING (IN THE CASE OF THE LOS ANGELES BASIN) OF NOX CREDITS AMONG OTHER THINGS, DRS. HOGAN AND HARVEY NOTED THAT YOUR MODEL DID NOT ATTEMPT TO FORECAST PLANNED OUTAGES. IS THIS CORRECT?

A. Yes. Utility industry practice has been to schedule prolonged outages – often as long as two months – on an annual basis. Such outages are scheduled in low load months. On the West Coast, such planned outages would usually be scheduled for late spring or early fall. The stylized nature of such planned outages has traditionally reflected the fact that such units are included in rate base. Utility earnings would not increase if these planned outages were minimized, since allowed earnings are based on invested capital and not plant operations.

Industrial facilities have very different incentives. For Pacific Northwest pulp and paper mills, the annual maintenance cycle is only two weeks.

Q. WHY ARE PLANNED OUTAGES SO MUCH SHORTER FOR INDUSTRIAL FACILITIES THAN TRADITIONAL UTILITY FACILITIES?

A. It is a question of incentives. The downtime of the power boilers at a paper mill idles the entire mill. The cost on a comparable basis can be hundreds or even thousands of dollars per megawatt.

Q. HOW WOULD MERCHANT PLANTS LIKE THOSE INCLUDED IN THE MODEL COMPARE TO THESE TWO EXTREMES?

A. Given the power prices that took place during the market crisis, their incentives should have been closer to those facing industrial facilities than traditional utilities.

Q. WHAT PLANNED OUTAGES WERE ASSOCIATED WITH THESE FACILITIES DURING THE MARKET FAILURE?

A. The planned outages were extensive. The outages were so extensive, in fact, that they were investigated by both FERC and the California PUC. The ISO has adopted new rules to make sure that such outages were appropriate.

Q. COULD THESE PLANTS HAVE BEEN MAINTAINED ON A NORMAL BASIS (REHABILITATION OF EQUIPMENT) GIVEN THE SCHEDULES DEVELOPED BY YOUR MODEL?

A. Yes. If the plants had been maintained in the spring of 2000 and 2001, this would have matched periods of low operation as predicted in our model.

Q. THE RESPONDENTS ARGUE THAT "OLD" PLANTS DON'T WORK VERY WELL. IS THIS CORRECT?

A. No. They probably meant to say that old equipment doesn't work very well. Industrial facilities work very well with power boilers considerably older than the steam units under discussion here. The chief of engineering at one of the large paper mills in Washington was particularly amused at this argument. He was fond of noting that his power boilers were older than he was.

Q. RESPONDENTS HAVE ARGUED THAT THE AGE OF THESE UNITS MAKES THEM INHERENTLY UNRELIABLE. IS THIS CORRECT?

A. No. GADS includes records from all of the units in their data base. It is easy to check what the availability factor is by unit.

Q. ARE THE AVAILABILITY FACTORS FOR UNITS LIKE THESE DOWN

ABOUT 50%?

A. No. As I have testified before, actual data gives relatively high availability for units like these. The table below provides GADS results by unit.

PUBLIC DOCUMENT – PAGES 95-97, 99-100, 102-103, 115 CONTAIN PRIVILEGED INFORMATION

Plant	Capacity	1995-1999 Availability	1999 Availability
Contra Costa 6	345	82.7%	83.7%
Contra Costa 7	347	82.7%	83.7%
Moss Landing 6	767	81.1%	81.0%
Moss Landing 7	768	81.1%	81.0%
Pittsburg 1	167	85.8%	85.4%
Pittsburg 2	163	85.8%	85.4%
Pittsburg 3	163	85.8%	85.4%
Pittsburg 4	163	85.8%	85.4%
Pittsburg 5	325	82.7%	83.7%
Pittsburg 6	325	82.7%	83.7%
Pittsburg 7	700	81.1%	81.0%
Alamitos 1	186	85.8%	85.4%
Alamitos 2	201	84.7%	82.4%
Alamitos 3	331	82.7%	83.7%
Alamitos 4	336	82.7%	83.7%
Alamitos 5	497	83.5%	81.3%
Alamitos 6	493	83.5%	81.3%
Cool Water 1	81	89.6%	88.3%
Cool Water 2	88	89.6%	88.3%
Cool Water 3	272	84.7%	82.4%
Cool Water 4	273	84.7%	82.4%
El Segundo 1	188	85.8%	85.4%
El Segundo 2	179	85.8%	85.4%
El Segundo 3	354	82.7%	83.7%
El Segundo 4	345	82.7%	83.7%
ENCINA POWER PLANT ST1-ST5, GT1	968	88.8%	83.6%
Etiwanda 1	132	85.8%	85.4%
Etiwanda 2	140	85.8%	85.4%
Etiwanda 3	340	82.7%	83.7%
Etiwanda 4	336	82.7%	83.7%
Huntington Beach 1	233	84.7%	82.4%
Huntington Beach 2	251	84.7%	82.4%
Mandalay 1	229	84.7%	82.4%
Mandalay 2	227	84.7%	82.4%
Morro Bay 1	171	85.8%	85.4%
Morro Bay 2	174	85.8%	85.4%
Morro Bay 3	347	82.7%	83.7%
Morro Bay 4	355	82.7%	83.7%
Ormond Beach 1	794	81.1%	81.0%
Ormond Beach 2	792	81.1%	81.0%
Redondo Beach 1	185	85.8%	85.4%
Redondo Beach 2	165	85.8%	85.4%
Redondo Beach 3	497	84.4%	84.4%
Redondo Beach 4	503	84.4%	84.4%
South Bay 1	160	85.8%	85.4%
South Bay 2	158	85.8%	85.4%
South Bay 3	187	85.8%	85.4%
South Bay 4	238	84.7%	82.4%

Q. DOES THIS MEAN THAT AN OVERALL AVAILABILITY RATE IN THE INDUSTRY IS DRAMATICALLY HIGHER THAN THE ONES DISCUSSED IN CALIFORNIA?

A. Yes. To be fair, ISO record keeping on outages was sketchy and the ISO does not believe that data for the period of the California market failure is dependable. We simply do not know how reliable these units were. We do know that they operated far less than expected.

Q. PROFESSOR KALT MAKES THE POINT THAT THESE UNITS PRODUCED MORE POWER IN 2000 THAN IN 1999. IS HE CORRECT?

A. Yes. The question isn't whether they produced more power, however. The question is how well they functioned. Dr. Kalt's approach is to note that while they failed in their appointed mission, they did not fail entirely.

Q. DID THEY FAIL?

A. Yes. By design, these units are meant to operate in a block dispatch mode. In a perfect world, they would have been dispatched for an entire on-peak period. When prices were high enough, they should have operated for weeks or months at a time. California's failed experiment did not provide for a simple way to assure block dispatch. Since bids into the PX were hourly, the owners of these plants were never able to assure efficient operation. Failing efficiency, however, they should still have been available during Stage 1, Stage 2, and Stage 3 emergencies.

Q. IS IT POSSIBLE THAT THESE PLANTS WERE ALWAYS BROKEN AND THAT THE CAPACITY VALUES WE HAVE ASSOCIATED WITH THEM WERE IN ERROR?

A. No. The problem isn't that they were unable to operate at capacity. All but two of the plants in our detailed analysis had maximum operating rates – actual metered operations – at or above their capacity. The problem was that the plants were not available during system peaks.

Q. THE RESPONDENTS' EXPERTS ARGUED THAT THESE LOW LEVELS WERE DUE TO ENVIRONMENTAL CONSTRAINTS AND SPECIAL OPERATIONAL CONDITIONS. IS THIS LOGICAL?

A. Not very. The assumption that constraints on NOx emissions would stop generation during a system emergency is very unlikely. If NOx emissions were a problem, a responsible plant owner would reduce generation off-peak and attempt to keep the lights on. If such restrictions did affect the capacity of the unit, these restrictions should have been factored into to the capacity assumed for reliability purposes.

Q. DRS. HARVEY AND HOGAN ARGUE THAT YOUR DISPATCH MODEL SHOULD USE CITY GATE GAS PRICES AS OPPOSED TO PURCHASES AT THE BORDER. ARE THEY CORRECT?

A. No. City gate prices are appropriate in some cases. Natural gas purchases by major market participants would be more likely to be at the lowest prices available. It is unlikely that they would be purchasing at city gate prices.

Q. SEVERAL TIMES THE COMMENT IS MADE THAT THE SOURCE OF THE GAS PRICE DATA IS "UNEXPLAINED." IS THE PRICING DIFFICULT TO FIND OR COMPUTATIONALLY CUMBERSOME?

A. No. We assumed that the generator would purchase the least expensive gas from the options available to them and then added transportation appropriate to Northern or

Southern California. All of the gas prices are taken from standard natural gas sources.

Q. WOULD WILLIAMS, FOR EXAMPLE, BE BUYING GAS AT CITY GATE PRICES?

A. This would be surprising, since one of the reasons for the AES/Williams tolling agreement was Williams' expertise in the natural gas business.

Q. HOW WOULD YOU CHARACTERIZE THE ARGUMENT MADE BY DRS. HARVEY AND HOGAN?

A. They have assumed that each of these generators would purchase gas at a relatively high city gate price. We have assumed that they would purchase gas at market prices and then transport the commodity to their facilities.

Q. IS THIS A CAUSE FOR "OVERDISPATCH" IN THE MODEL?

A. No. This would only be the case if Drs. Harvey and Hogan have evidence that the generators are inefficient in their natural gas purchasing.

Q. RETURNING TO THE DISCUSSION OF NOX EMISSION CREDITS ABOVE, DRS. HARVEY AND HOGAN COMPLAIN THAT YOU DID NOT REDUCE THE COST OF NOX CREDITS TO $7.50 IN JUNE. IS THIS CORRECT?

A. Yes. We used a simple monthly average of market pricing for NOx credits throughout the entire period under analysis. Our assumption was that changes in these rules would show up in the market pricing data.

While this is a sensible assumption, it underestimates the difficulty dealing with the pricing data in this particularly opaque market. Drs. Harvey and Hogan are arguing that we should use the prices that would have provided an incentive to generate and not data from the RECLAIM bulletin board. This is a reasonable suggestion.

Q. DRS. HARVEY AND HOGAN SEEM TO ASSUME THAT GENERATORS IGNORED THE IMPORTANCE OF THE STAFF PROPOSAL ON JANUARY 20, 2001 AND WAITED UNTIL A FINAL ORDER WAS SIGNED BEFORE ADJUSTING THEIR BEHAVIOR. IS THIS REASONABLE?

A. No. The clear intention of the SCAQMD was to set the prices to $7.50. It would have been irrational to believe that this intention would be thwarted during the course of the crisis. By opening this question of incentives, Drs. Harvey and Hogan also need to address when the $7.50/lb price began to affect generator behavior. We have rerun out model using the $7.50 value since the date of the staff proposal.

Q. HAVE THE RESULTS CHANGED TO ANY SIGNIFICANT DEGREE?

A. No. The results are unchanged. Over the period of the California market failure, these plants simply did not generate as much as similar plants under similar circumstances would have.

	Northern California	Southern California (Outside of SCAQMD)	SCAQMD	Total
	aMW	aMW	aMW	aMW
Forecasted				
Jan-97 to Mar-98	125.63	552.11	545.66	1,223.39
Apr-98 to Apr-00	2,097.07	2,145.22	2050.38	6,292.66
May-00 to Jun-01	4,081.24	4,631.54	4260.00	12,972.77
Jul-01 to Dec-01	2,702.32	2,790.27	1601.55	7,094.15
Actual				
Jan-97 to Mar-98	1,252.64	1,157.25	1060.72	3,470.61
Apr-98 to Apr-00	1,245.07	1,386.62	986.31	3,618.00
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
Difference				
Jan-97 to Mar-98	1,127.02	605.13	515.07	2,247.22
Apr-98 to Apr-00	(852.00)	(758.59)	(1,064.07)	(2,674.66)
May-00 to Jun-01	(1,502.63)	(1,863.16)	(1,807.17)	(5,172.95)
Jul-01 to Dec-01	(469.03)	(653.86)	672.40	(450.50)

Q. MR. BAIRD HAS POINTED OUT A VARIETY OF DATA ENTRY ERRORS IN YOUR WORKPAPERS. WERE THEY SIGNIFICANT?

A. No. We have benefited from his hard work and corrected the errors he has pointed out. None of the corrections change our results or our conclusions. Only one of his comments requires a response. He notes that a single data point in December of 2000 has been removed from the regression data. This is correct. As the FERC staff has pointed out, reporting of prices during the crisis has raised many questions. This particular data point simply doesn't fit logic of the hydroelectric based Pacific Northwest market. It implies a $2000 to $3000 on peak/off peak differential for a single day. We viewed this as an anomaly and removed it from the data set.

SECTION 4: A REVIEW OF THE RELATIONSHIP BETWEEN SPOT AND FORWARD MARKETS

Q. CAN YOU REVIEW THE THEORETICAL CONNECTION BETWEEN SPOT PRICES AND LONG TERM PRICES?

A. Yes. While respondents would have FERC believe that this is a complex and mysterious science, the reality is very simple. Spot prices reflect current supply and demand. The supply curve is based up on the marginal running cost of thermal power plants in the WSCC. The demand curve is based on the requirements of customers. While some customers will reduce their demand due to price, the effect is limited, so the demand curve is very steep. The price in a competitive market is set by the intersection of the line representing customer demand with the rising costs of thermal power plants. Given the nature of the electricity industry, the supply curve changes frequently. Plant and transmission outages and changes in fossil fuel prices occur frequently. The demand curve also changes frequently with weather related changes in heating and cooling demands.

Long term prices reflect the alternatives to a long term contract. Throughout the history of the industry this has usually been plant construction. Depending on the duration of the long term contract, some short term or spot supplies might be included in the long term contract price. For example, a long term contract for five years, starting next month, would include spot pricing for the immediate future.

While there is no *a priori* reason why spot prices should always be less than long term prices, the fact that long term prices reflect full plant costs – fixed costs plus variable costs – and spot prices represent the running costs of the highest cost running unit, have tended to keep spot prices less than long term prices.

Q. WHAT WENT WRONG WITH THIS THEORY DURING THE CRISIS?

A. Once spot prices began to diverge from the cost of the highest cost running unit, it was impossible for anyone in the market to accurately predict what was going on. On one hand, the authoritative WSCC forecasts showed business as usual. On the other hand, the California ISO had begun to announced Stage 1 and Stage 2 emergencies every few days. California data was highly restricted so it was difficult to understand the cause for these announcements. A number of respondents to this case announced that the cause was a long term lack of supply in California and predicted that the crisis would go on for years to come. As Professor Hogan said on June 13, 2001,

> The energy market problems in California are serious. As Governor Gray Davis said, the recent good fortune, with several factors combining to produce lower prices in California, is probably only a "temporary reprieve." It is likely that the problems of high prices and rolling blackouts in the west will be with us again this summer. It is appropriate that this committee is addressing the topic, in order to understand the origins of the

difficulties and to identify actions that might improve the situation.[26]

Obviously, if Dr. Hogan couldn't predict the immediate future in California, market participants had little to go on in the long term. The sheer lack of information and the collapse of fundamentals as an explanation of events, meant that market participants had to judge the future by what they knew of the present.

In this environment, opportunity cost of spot transactions was an important part of these calculations. The seller of a long term power contract would not make that transaction if it was "likely that the problems of high prices and rolling blackouts will be with us again." Given the frequent predictions that such conditions would last from two to four years, only a very brave individual would not use the opportunity cost of sales into the spot markets as a floor for long term contract prices.

Q. THE RESPONDENTS APPARENTLY BELIEVE THAT THE SIMULTANEOUS FALL IN BOTH SPOT AND FORWARD PRICES AT THE END OF THE CALIFORNIA CRISIS WAS A COINCIDENCE. HOW REALISTIC IS THIS?

A. With the exception of the "structural model" mentioned at the end of the testimony of Drs. Harvey and Drs. Hogan, the discussion of the decline has been sketchy to say the least.

---

[26] Statement of Professor William W. Hogan Before the Committee on Governmental Affairs, United States Senate,

Q. HAVE YOU REVIEWED DR. KALT'S "FACTORS RELEVANT TO FORWARD CONTRACT PRICE DECLINES IN THE WESTERN U.S. DURING THE SPRING AND SUMMER OF 2001" EXHIBIT?

A. Yes.

Q. CAN YOU WALK THROUGH HIS LIST AND POINT OUT THE PROBLEMS?

A. Yes. Dr. Kalt begins by noting that payment problems forced a number of QF generators offline during the early spring. While he is correct, the factors that caused this problem were quickly recognized and repaired. He would have us believe that traders were assuming that this problem would last for a prolonged period even though recovery was well underway in May and largely over by May. His repair of San Onofre was equally predictable. Every market participant knew that the plant would be repaired and back on line. The arrival of this plant in June was hardly new information for the markets in May.

Again, rate increases in California were known in advance and the impact of prices on load is well understood.

Gas prices did decline as 2001 went on. The problem Dr. Kalt has is that to this day, no one understood why the basis between California and surrounding regions had grown so high. If the crisis had continued, the anomalous pricing of gas might well have continued

---

June 13, 2001.

{B0076111; 1}

as well. As I mentioned above, FERC staff has expressed significant doubts about the pricing of natural gas in California over this period.

Dr. Kalt's citation to new generation is hardly convincing. The plants under construction were hardly a surprise to anyone in the market. Enron, for example, was following them on a month by month basis.

NOx emissions prices did decline, but since the staff recommendation was put forward on January 20, 2001, only a very indifferent analyst would have missed the fact that RTCs to generators in the L.A. Basin had effectively been pegged at $7.50.

Finally, Dr. Kalt cites the PG&E bankruptcy as easing credit risk fears. While Dr. Kalt's interpretation is questionable – few creditors actually like to see a major account enter Chapter 11 – the fact is that this could hardly been a surprise to the long term markets the month after it happened.

Overall, five of his six factors were well understood before the price decline. The remaining factor, the unusually high basis between California and surrounding states is still under debate today.

SECTION 5: FORWARD PRICES AND EXPECTATIONS DURING THE CALIFORNIA CRISIS

Q. NUMEROUS WITNESSES FOR THE RESPONDENTS CLAIM THERE IS NO LINK BETWEEN THE SPOT AND FORWARD MARKETS BECAUSE DIFFERENT EXPECTATIONS GOVERN PRICES IN THOSE MARKETS. WAS THIS THE CASE DURING THE WEST COAST CRISIS OF 2000-01?

A. No. A careful review of the facts demonstrates that the predominant factor driving both spot and forward markets was the expectation that market dysfunction, and the extremely high prices associated with dysfunction, would continue for two to four years.

Q. **WHAT WAS THE MARKET PERCEPTION DURING THE FIRST PHASE OF THE CALIFORNIA CRISIS?**

A. Emergency declarations during the summer of 2000 were based on a shortage of sufficient offers to allow the California ISO to meet its reserves objectives. There was no physical shortage of generation assets – the reserve margin was above 13% -- but merely a shortage of offers to the ISO in the day-ahead markets, forcing the ISO to make astronomical bids to keep the lights on.

Q. COULD PRUDENT TRADERS HAVE PREDICTED THE CRISIS IN APRIL 2000?

A. No. In April 2000, traders had a fair level of confidence in the fundamentals that were being developed by their backoffice. Electric prices had followed a straightforward model for many years. Uncertainties existed, but forward curves could be easily taken from open financial exchanges like the Block Forwards Market at the Power Exchange or the Palo Verde and COB NYMEX exchanges.

Q. HOW WOULD A PRUDENT TRADER APPROACH PROBLEMS SUCH AS THIS?

A. A prudent trader has two basic assets. His judgments are based upon a detailed fundamentals analysis by the back office staff. The forecast gives him the best possible picture of the future months that he is trading in.

Q. DO WE HAVE THE FUNDAMENTALS ANALYSIS FROM THE RESPONDENTS IN THIS CASE?

A. No. The respondents simply refused to turn over their fundamental analysis of the market. We do have fundamentals from Enron, which closely match research done by utilities and the WSCC. They reviewed WSCC load and resource studies, reviewed hydro conditions, and analyzed shifts in fuels.

Q. WHAT IS THE SECOND ASSET A TRADER BRINGS TO HIS JOB?

A. The trader's second asset is his personal judgment. Each trader is assigned a value at risk limit. Within this limit, he is expected to use his judgment and the research of his firm to take advantageous positions in the market. Thomas Funk makes this point in his deposition:

(Ex. SNO-65)[27]

Q. WERE THE FORCES THAT INCREASED SPOT PRICES CLEAR AT THE TIME?

A. No. Much of the data we know now was only available months later. Simon Greenshields noted **(Ex. SNO-66)**.[28] When asked whether **(Ex. SNO-66)**.[29]

Q. DID MORGAN STANLEY FORECAST THE START OF THE CALIFORNIA MARKET FAILURE?

No.

---

[27] Thomas Funk Deposition, Page 76, lines 12-20.
[28] Simon Greenshield's deposition, pages 163 and 164.
[29] Ibid., page 165, lines 10 and 11.
[30] John Woodley deposition, page 48, lines 2-4.

Q. HOW DID THIS SITUATION LOOK IN JUNE 2000?

A. Anyone who had relied on standard analysis would have been badly injured in the market. If our hypothetical trader had sold a one month on-peak product and expected to cover his trade from the spot market, he would have lost a vast amount of money.

Q. WAS THIS TRUE THROUGHOUT THE SUMMER?

A. Yes. The analysis of the summer of 2000 from May 1st, 2000, would have failed to predict actual prices in every month.

Q. AT THE END OF THE SUMMER, WHAT WOULD THE TRADER HAVE DECIDED ABOUT HIS FUNDAMENTAL MODEL OF THE CALIFORNIA ISO?

A. He would have decided, as I did, that it was difficult to give much weight to traditional fundamental analysis.

Q. HOW WOULD THE TRADER HAVE VIEWED THE MARKET IN OCTOBER?

A. In October, spot prices were down, fundamentals had improved, and long term prices had leveled out. The trader had some hope that his forecast of the winter would be better than his forecast of the summer had been. Winter prices reflect peak loads in the Pacific Northwest, not California. The major uncertainty facing the trader in the winter was the depth of the snowpack that was accumulating in the U.S. and Canadian Rockies. The impact of this snowpack is estimated at the turn of the year in what is called the "early bird" forecast.

Q. HOW WOULD THE EVENTS OF NOVEMBER HAVE AFFECTED THE TRADER'S MODELS?

A. The ISO declaration of an emergency in November was an even more crushing blow to fundamental analysis than the events of May. November loads are low in California. California has a large excess of resources over loads in that month.

Q. WOULD HE HAVE KNOW WHAT THE CAUSE OF THE EMERGENCY WAS?

A. Not really. During this period the ISO kept plant outage data secret. He might have press coverage of the problem, but fundamental data was very difficult to come by. The ISO's decision to stop distributing "confidential" plant operating data through the WSCC would also have reduced the fundamental information he had to work with.

Q. HOW WOULD A TRADER DEVELOP A STRATEGY TO DEAL WITH THIS?

A. The first step would be to become more cautious. We can see the impact of this in the steady decline of open contracts on the NYMEX exchanges. The second step would be to rely more on current market information and less on the back office research.

Q. IS THIS WHAT HAPPENED?

A. Yes. Everyone in the utility community became far more risk adverse. I participated in such discussions with suppliers, utilities, and large industrials who had been active in the market.

Q. IN WEIGHTING THE TWO APPROACHES TO TAKING TRADING POSITIONS – FUNDAMENTALS AND MARKET JUDGMENT – HOW WOULD THE MIX HAVE SHIFTED?

A. The shift was clearly to market judgment. BPA effectively put away its market forecasting tool, Aurora, in the BPA rate case. The ability to forecast gas prices also declined enormously over this period. Walt Pollock, the very experienced power manager at PGE during this period, coined the phrase "can't go wrong to go long."

Q. WHAT DID HE MEAN BY THIS?

A. If you can't forecast the future, take as few risks as possible.

Q. ENTERING THE SPRING, HOW WOULD A TRADER DECIDE ON HIS FORWARD POSITION?

A. This isn't easy. Trading had virtually ceased on the NYMEX exchanges. The December 15, 2000 FERC order had effectively closed the Block Forward Market. Market transparency had declined significantly. Surveys were still available, but trusting to pricing by Enron on EnronOnline exposed the traders to the risk that Enron was promoting a position that would be in Enron's self-interest. In a sense the lack of transparency and the failure of fundamental models made all of the market participants into "day traders."

Q. DO WE HAVE ANY EVIDENCE THAT MORGAN STANLEY DEPENDED ON ENRONONLINE?

A. Yes from the Funk deposition:

Q. HOW DID MORGAN STANLEY SEE THE MARKET?

A. In one of the few documents we have been able to procure, Morgan Stanley provided their "due diligence" review for 1st Quarter 2001. It reviewed the 2001 and 2002 markets:

> In the quarter, California wholesale power prices were up 80% for 2001 and close to 50% for 2002. The crisis has now engulfed the Northwest. In addition to the aforementioned drought conditions, the Bonneville Power Administration (BPA manages the Northwest power grid) has a California mess to contend with. In trying to meet its own power needs, hydroelectric generators on the Northwest were forced to let their river reserves flow to help light up California. The river water that was being dammed to reserve capacity to meet the Northwest's summer demand has been greatly diminished. The market is now anticipating supply problems for California and the Northwest. The result has been an astounding 300% increase in 2001 prices and a relatively similar gain for 2002. Again our desk has traditionally been long in the front years then, short the back end of the curve. In recent weeks however the desk has taken the opportunity to sell power short in specific locations and time periods. Traders feel there is some "hot air" in the market that needs to be let out **(Ex. SNO-69)**.[32]

Q, HOW DID FUNDAMENTALS FIGURE IN THIS SHORT ANALYSIS?

A. The only fundamental cited, hydroelectricity, applied only to 2001. River flows are

[31] Thomas Funk Deposition, page 53, lines 6-9.

different each year, so low hydro in 2001 does not tell the trader what they will be in 2002. The clear interpretation is that Morgan Stanley was judging 2002 from the perceived disaster in 2001.

Q. IS THIS A CASE OF FORWARD PRICES TAGGING ALONG BEHIND SPOT?

A. Absolutely.

Q. HOW WOULD THE WEIGHTING BETWEEN SPOT INFORMATION AND FUNDAMENTALS HAVE CHANGED IN THE SPRING?

A. Starting in January the ISO was declaring Stage 3 Emergencies every morning, even though their loads were relatively low. FERC had removed the PX tariff, creating confusion in the markets that depended on the PX as a scheduling coordinator. Financial risk was high. Information on the state of affairs in California was so poor that McCullough Research started issuing a daily ISO load/resource balance report for our clients and a number of California state agencies. A prudent trader would have given very little weight to fundamental models by the spring of 2001.

Q. DID THE MARKET PARTICIPANTS PREDICT EITHER THE ONSET OF THE CRISIS OR ITS SUDDEN DEPARTURE?

A. While we have experienced difficulty in obtaining market fundamental reports from respondents, we know that Enron, for example, failed to predict either the onset or the sudden disappearance of the crisis. We also know that MSCG failed to predict either the onset or the disappearance of the crisis, as explained in the Rebuttal Testimony of

[32] MSCG 004280.

William Kemp **(Ex. SNO-73 at 23-24).**

Q. WHAT EXPLANATIONS HAVE MORGAN STANLEY GIVEN FOR THE DECLINE?

A. Simon Greenshields cites regulatory intervention as a possible cause:

> **Q, AND WHAT ABOUT THE REGULATORY INTERVENTION? DID THAT HAVE AN IMPACT ON FORWARD PRICES?**
>
> A. Regulatory intervention possibly had an impact on forward prices (Ex. SNO-70).33

This is interesting because FERC's regulatory intervention affected spot, not forward contracts.

Q. WHAT IS THE SIGNIFICANCE OF THE FAILURE TO SUPPLY SUCH MATERIALS?

A. Every respondent in this proceeding has failed to supply documents that would corroborate the theories of their experts.

Q. DID MR. GREENSHIELD'S IDENTIFY THE SPECIFIC REGULATORY IMPACT THAT AFFECTED FORWARD PRICES?

A. Yes. In his deposition, Mr. Greenshields said:

Mr. Greenshields goes on to explain:

Q. WHY DID YOU USE A SIMPLE LINEAR MODEL TO ESTIMATE THIS COMPLEX SET OF RELATIONSHIPS BETWEEN FUNDAMENTALS AND JUDGMENTS BASED ON SPOT MARKETS?

A. A simple inspection of the data shows that the spot and forward data lies along a diagonal line through the origin. A simple inspection of the pattern of forward and spot prices shows that forward prices "tagged along" over time. By the late spring, spot and forward prices are very, very similar.

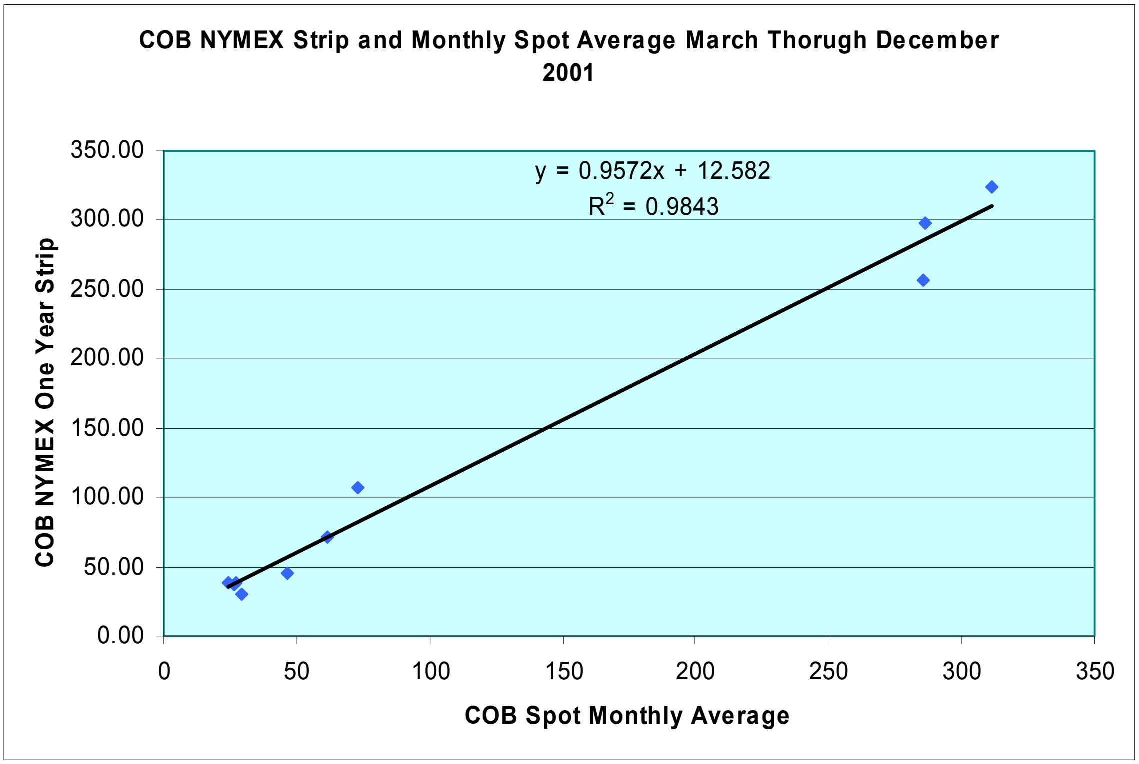
The following chart shows how close the relationship was between the monthly average

[33] Simon Greenshields deposition, page 172, lines 2-6.
[34] Greenshields deposition, p.151, lines 17-25.
[35] Id. at 152, lines 2-9.

spot prices and the monthly average NYMEX one year strips at the close of the crisis.

Q. DR. KALT MAY BE CONCERNED THAT THIS GRAPH MEANS THAT THE CLOSE RELATIONSHIP "CAUSES" THE ECONOMIC RELATIONSHIP DISCUSSED ABOVE. IS THIS CORRECT?

A. No. The graph merely illustrates that the relationship is very close. The causal relationship, as demonstrated above, is that the crisis had essentially destroyed the forward market and any reliable information about forward market fundamentals were unreliable or non-existent, and there was an expectation that the market dysfunction would continue for a long period.



SECTION 6: RESPONDENTS' SPECIFICATION OF THE RELATIONSHIP BETWEEN SPOT AND FORWARD PRICES

Q. HAVE YOU REVIEWED THE STATISTICAL REBUTTAL FILED BY THE RESPONDENTS?

A. Yes.

Q. WHAT IS YOUR REVIEW OF DRS. HARVEY AND HOGAN'S ARGUMENTS?

A. The fundamental problem that the respondents have to solve in their testimony is that the unjust and unreasonable spot prices provided the opportunity cost for long term transactions. They contend that during the time period in question, the spot and forward markets operated largely independently. They are disadvantaged by the established fact that the long term prices "tagged" along behind spot prices throughout the period of the market failure.

Q. HOW HAVE THEY SOLVED THAT PROBLEM?

A. They have largely ignored the factual reality by focusing on an attack on the statistical model used to fit the data.

Q. HOW DO YOU RESPOND TO THE LARGE NUMBER OF ALTERNATIVE EXPLANATIONS, MODEL SPECIFICATIONS, AND STATISTICAL TECHNIQUES EMPLOYED BY DRS. HARVEY AND HOGAN, AND TO A LESSER EXTENT, BY DR. KALT?

A. Simple models are better than more complex models. Models with economic underpinnings are far more convincing than models that would appear to be an appropriation of different elements combined only for the purpose of assembling a statistical result.

Q. WHAT IS YOUR OPINION OF THEIR ADJUSTMENTS TO YOUR SIMPLE REGRESSION?

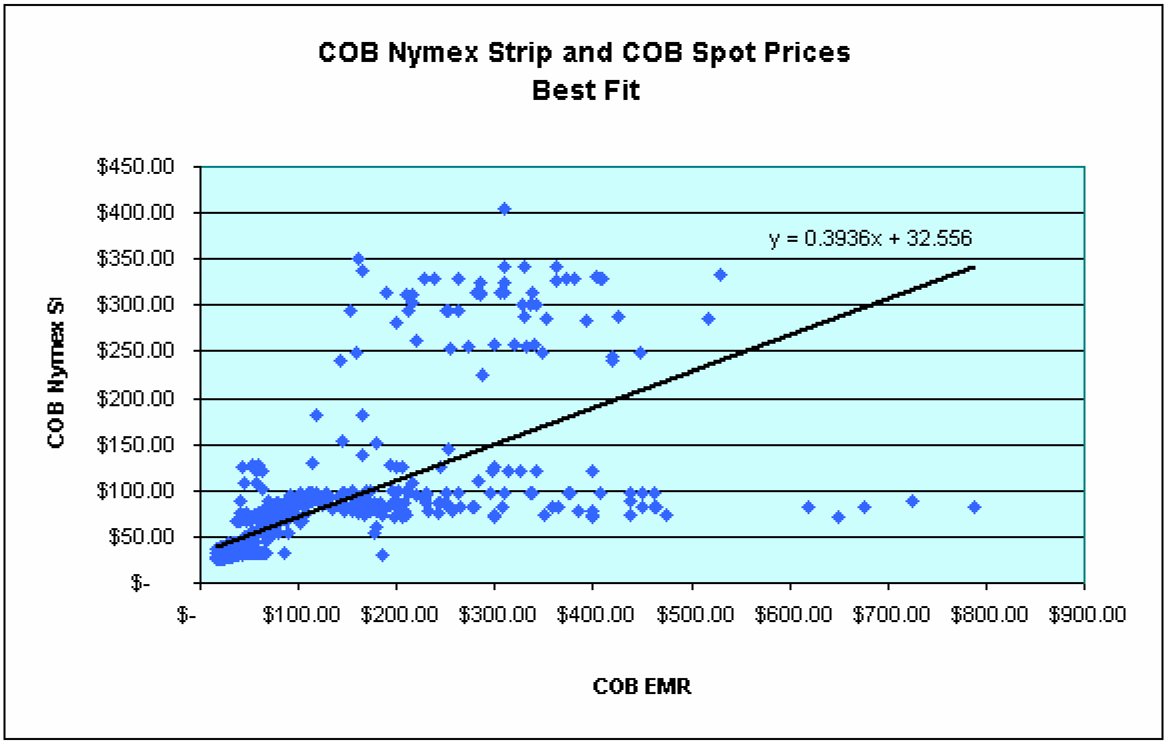
A. Drs. Hogan/Harvey have made the classic logical error of imposing a theory on the data and then trying to draw conclusions from the assumed theory. The high correlation between spot and long term pricing over this period is an actual fact. The regression line drawn through the points in my testimony is a short hand way of describing the relationship between the two sets of data.

The regression line between the two sets of points shows the relationship between spot and long term prices. While an infinite set of different relationships between the long term prices and the spot prices can be imagined and graphed on this chart, the simple approach is preferable in this instance.

Dr. Hogan has chosen a somewhat less direct theory. He believes that the best possible relationship between long term prices and spot prices is a straight line where the estimated error terms have been corrected so that each error term meets a theoretical standard he has imposed on the data.

Q. **CAN YOU SUMMARIZE YOUR APPROACH?**

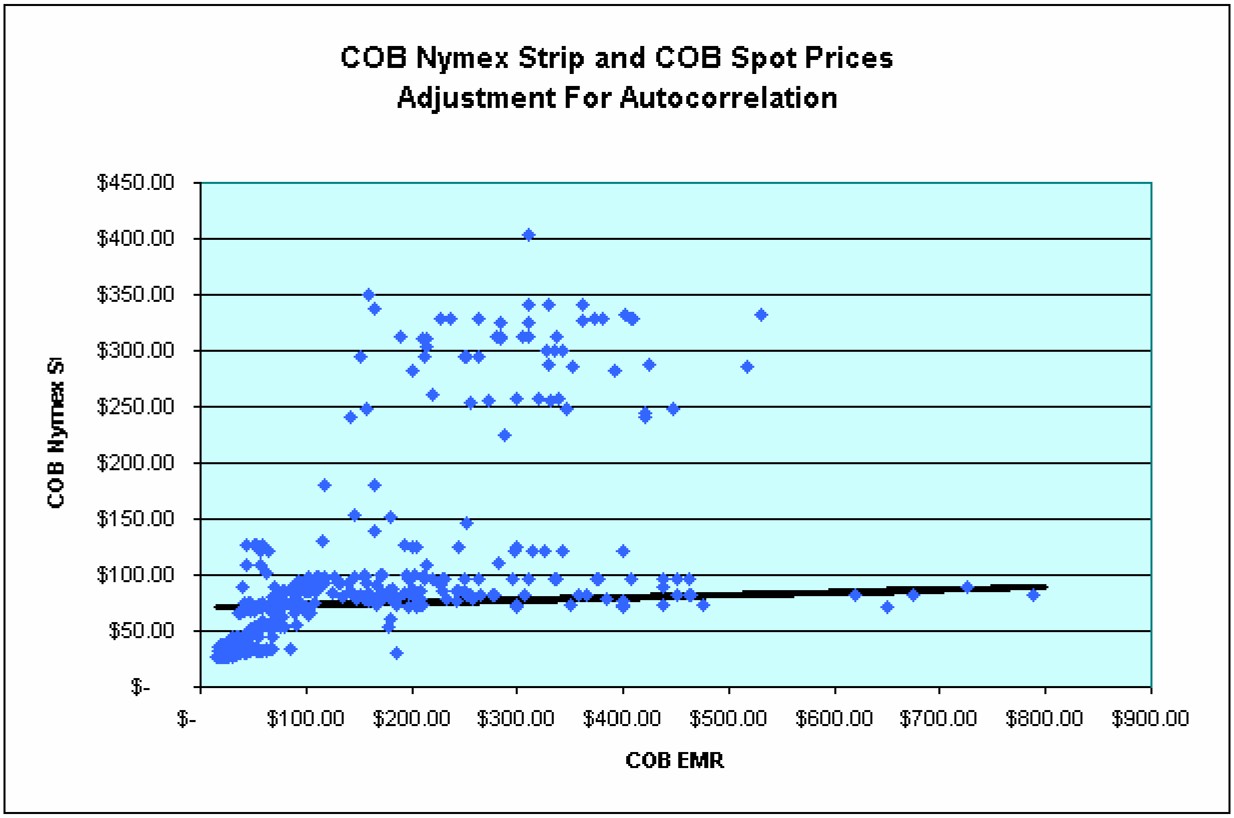
A. Yes. A simple inspection of the data provides a counterexample against the hypothesis that spot and forward prices are unrelated. Our approach is to find the line that fits the data the most closely In the chart above, a straight line represents the closest fit to the data we actually observed. The line climbs as spot prices increase. This reflects the fact that higher forward prices followed higher spot prices throughout the crisis and fell at the same time at the end of the crisis.



Q. CAN YOU GRAPH THE LINE THEY DERIVED AGAINST THE DATA?

A. Yes. It is easy to show the relationship they believe fits the data best once the data has been corrected for autocorrelation, a technical problem that occurs when errors terms are related over time. Some of the parameters of this line are assumed since not all of the parameters have been reported.

Drs. Harvey and Hogan find that a line, very close to horizontal, is the most efficient estimate of this relationship. As can be seen in the chart below, this line doesn't fit the strong diagonal grouping of the data.



Q. THEIR LINE DOESN'T SEEM TO DESCRIBE THE DATA WELL AT ALL. WHAT IS THE PROBLEM?

A. They have imposed a condition on the data that may not, and almost certainly, does not exist in the real world. The data on this chart reflects surveys of prices during the crisis. As a theoretical issue, it reflects the tendency of long term prices to be quoted above the opportunity cost of expected future spot prices.

The model proposed by Drs. Harvey and Hogan implicitly assumes that traders have made their calculations by adjusting the error terms in their models for the error term of the previous day. It so happens that the line Drs. Harvey and Hogan have derived fits the data poorly, meaning that the traders would discover that the entire data set could be disregarded. So the hypothetical Harvey/Hogan trader in the forward market makes complex statistical adjustments that lead him to believe that he can safely ignore the spot market in all his calculations.

The problem with the respondents' position is that we simply do not have any *a priori* evidence that the error terms meet the assumptions of the standard statistical model.

Q. HAS THIS EVER HAPPENED BEFORE IN ECONOMICS?

A. Yes. It happens very frequently. In the case of price data, circumstances often extend across several time periods. This tends to lead to autocorrelation.

Q. DOES THIS MEAN THAT THE DATA IS REMOVED FROM THE DISCUSSION?

A. No. In most economic data, autocorrelation is a factor. This does not stop economic actors from making logical decisions based on the evidence.

Q. PLEASE CHARACTERIZE THE STATE OF THIS DEBATE.

A. The best fit of the spot and forward data matches the economic intuition of anyone viewing the graph. Throughout the crisis, forward prices were higher than expected during the same periods when spot prices were higher. If we attempt to characterize the results using the assumptions of the standard statistical model, the presence of autocorrelation may affect the statistical conclusions. (We note, however, that even in the presence of autocorrelation, the coefficient estimates remain unbiased.) An alternative is to assume the standard statistical model is correct, and to force the data into this structure. If this is done, the answer is that the common sense relationship obvious to the eye – and economic logic – disappears.

Q. IS THERE ANY THEORETICAL OR PRACTICAL EVIDENCE THAT TRADERS MADE ADJUSTMENTS COMPATIBLE WITH HARVEY AND HOGAN STATISTICAL MODEL OF FORWARD PRICING?

A. No. In theory, if a trader were to adjust his pricing in a manner that tracked Drs. Harvey/Hogan's statistical model, the trader would price contracts at a level that was less than opportunity cost. Obviously, the relationship between the high long-term prices and spot prices is not dependent on a specific specification of a statistical relationship – especially one which has no *a priori* theoretical logic.

Q. DO DRS. HARVEY AND HOGAN PROVIDE ALTERNATIVE MODELS?

A. Yes. In addition to the adjustments described above, they add dummy variables to correct for seasonality and monthly impacts. They are adding 11 dummy variables to represent a stable monthly pattern with a data set of only 36 months of data , for a period that includes the most extraordinary price change in the industry's history.

Q. WHAT ECONOMIC LOGIC IS PRESENT HERE?

A. At this point, we have returned to data dredging. We know the pattern of prices during the market failure period was largely inexplicable. Correcting the problem by replacing the impact of specific time periods with dummy variables is equivalent to removing dates that Drs. Harvey and Hogan are uncomfortable with.

Q. **DO DRS. HARVEY AND HOGAN ATTEMPT TO JUSTIFY THEIR MODEL IN TERMS OF THE UNDERLYING ECONOMICS?**

A. No.

Q. HAVE YOU REVIEWED THE "OMITTED VARIABLES" ANALYSIS OF DRS HARVEY AND HOGAN?

A. Again, they have approached the problem by using a complex model without a clear set of economic underpinnings. They contend that

> The forward gas prices are highly correlated, but we are not trying to estimate their individual effects, we are only trying to hold changes in these forward prices constant.[36]

Q. WHAT IS THE RESULT OF THEIR REGRESSION?

A. In some cases, an increase in gas prices appears to lower electric prices. The basic problem is the same as the models discussed above. Drs. Harvey and Hogan have an enormous number of alternative specifications. They have so many specifications that sheer probability will show statistically significant results after enough tries. In this case, they like the result of the model, but they fall victim to the fact that it has illogical results. The simple fact is that they have created largely arbitrary models with complex specifications in order to explain away a commonsense factual embarrassment.

Q. DO DRS. HARVEY AND HOGAN HAVE ANY OTHER MODEL SPECIFICATIONS TO TEST?

A. Yes, on page 140 of their testimony, they propose a "structural model"

> that included current PG&E and SoCal gas prices, current average monthly U.S. WSCC hydro output, WSCC reserve margin and California nuclear plant output to predict the current COB spot price. We then controlled for the PG&E and SoCal forward gas prices, and assumed that the forward market expectations for future hydro output, reserve margins and nuclear plant output were for normal output. The results of this model again showed no relationship between spot and forward prices.[37]

Q. HOW MANY DIFFERENT SPECIFICATIONS OF THIS MODEL DID THEY TRY BEFORE THE ENDED UP WITH JUST THE RIGHT RECIPE?

A. It is impossible to know, but the sheer potpourri of model ingredients makes it very unlikely that this specification was created from a cogent economic analysis. For example, Drs. Harvey and Hogan have chosen to eliminate hydroelectric generation in Canada. Given the importance of Canada to the hydroelectric system (the Columbia River flows from the U.S., through Canada, and then back to the U.S.) it is unlikely that this was the first set of data they tried. The use of nuclear generation is very curious, since nuclear plants are never at the top of the dispatch curve. In spite of the fervent arguments concerning the importance of RTC prices to spot prices in the WSCC, Drs. Harvey and Hogan have dropped them from this model as well.

---

[36] Ex. MSCG-65 at 137.

The "control" for future hydro output is a highly complex undertaking that would tax the most skilled analyst since this model would necessarily include data across several years. In this case, the problem would be more complex because they have dropped a sizable portion of the hydroelectric generation in the WSCC from their model.

Q. DID THEY REPRODUCE THE RESULTS OF THIS MODEL?

A. It isn't clear. There is no citation to a table in their testimony. None of the tables at the end of their testimony would appear complex enough to describe this pastiche.

Q. DO YOU APPROVE OF THEIR APPROACH?

A. Absolutely not. This is another case of an arbitrary specification driving an arbitrary result.

Q. DRS. HARVEY AND HOGAN STATE THAT THE EVIDENCE OF DEVIATIONS BETWEEN ACTUAL MARKET DATA AND THE DOW JONES INDEX WAS NOT PROVIDED IN DISCOVERY ARE THEY CORRECT?[38]

A. No. This was provided in response to MSC-SNO-230.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON DR. KALT'S STATISTICAL CONTRIBUTIONS TO THIS DEBATE?

A. Yes. Dr. Kalt was far less energetic in his attempt to avoid recognizing the fact that spot and forward prices fell together at the end of the California market failure. Dr. Kalt

[37] Id. at 140.
[38] Ex. MSCG at 134, line 11.

asserts that my analysis confuses correlation with causation. In point of fact, the testimony from MSCG cites the deposition where I made clear that . **(Ex. SNO-72)**.[39]

Q. WHAT SHOULD FERC TAKE FROM THIS MELEE OF MODEL SPECIFICATIONS?

A. A single simple fact. In spite of what must have been thousands and thousands of regressions, Drs. Harvey, Hogan and Kalt have not presented a single cogent explanation of why spot prices and forward prices declined at the same time and in comparable magnitude. The scope of their effort without a single positive result tells more than all of their regressions. At the end of an enormous effort, they do not have a single systematic explanation of the plainest of facts.

Q. **DOES THIS COMPLETE YOUR REBUTTAL?**

A. Yes.

[39] McCullough deposition p. 86 line 22 to p. 87 line l.