California Independent
System Operator

CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Ph.D., Director of Market Analysis

cc: ISO Officers, ISO Board Assistant

Date: June 19, 2003

Re: **Market Analysis Report for May 2003**

This is a status report only. No Board Action is required.

Executive Summary

With the change to daylight savings time and warmer temperatures, load is now peaking in the afternoon following its normal summer-season pattern. The average prices in May for incremental and decremental balancing energy were $88.36 and $5.81 per megawatt-hour, respectively. The peak-load for the month of 39,502 megawatts[1] (MW) occurred on May 28th. An inaccurate weather forecast for that date necessitated large procurement of real-time energy to balance forward schedules with actual load, causing a price spike that lasted over 5 hours. With so little incremental procurement in most other hours, the event accounted for nearly 11 percent of all incremental energy in May.

Natural gas prices were relatively stable in May, in the range of $5.50 per million British thermal units (MMBtu) since the end of the price spike in late February and early March continuing at nearly double last year's levels.

I. Market Trends in May 2003

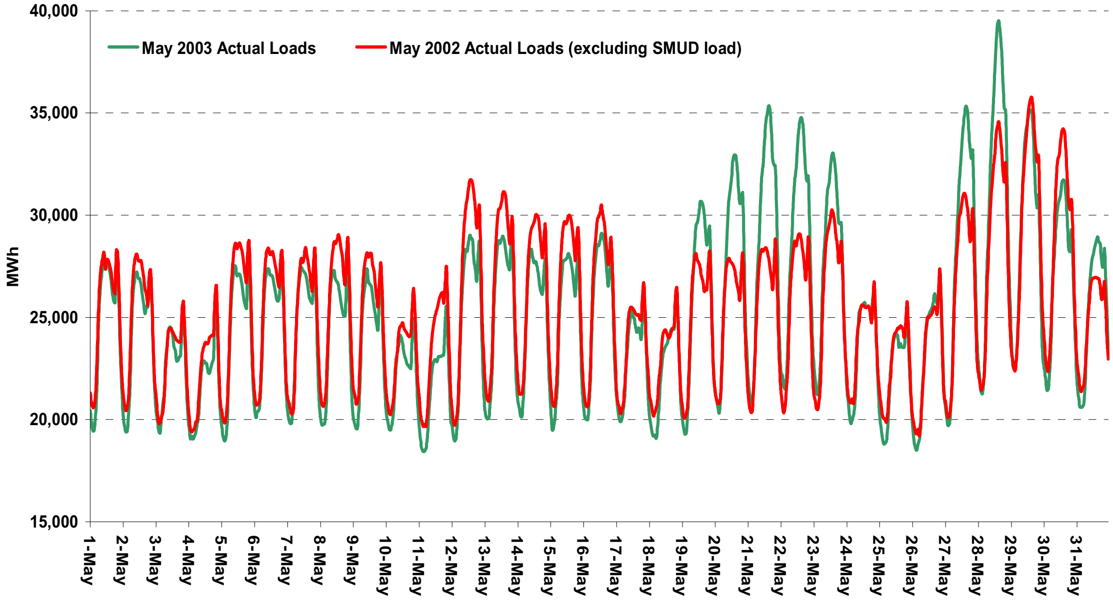
The spikes in real-time incremental balancing energy prices that had persisted for the first two months of spring were much less evident in May due in large part to the seasonal shift in load. Because loads now peak in the late afternoon, the evening drop in load is no longer as sharp in hour ending (HE) 22:00 (the hour between 9:00 and 10:00 p.m.) as it had been in recent months.

While the winter season rain lingered through April in the West, the hot and dry summer weather arrived early. Unseasonably warm weather abruptly replaced unseasonably cool weather beginning May 20. The effect of the rapid temperature change was most apparent on May 28, when the daily peak load reached 39,502 MW. By comparison, the load was 29,026 MW on May 16, so there was an increase of 10,476 MW (36.1 percent) within two weeks. The May 28 peak

[1] Top-of-hour loads. May differ from instantaneous intra-hour loads.

was 10.5 percent higher than the May 2002 peak of 35,756 MW. Weather forecasts predicted temperatures as much as 14 degrees below actual levels on May 28. Consequently, electricity demand on that day was well in excess of forward schedules, and the imbalance covered by incremental energy in the real-time market exceeded 3,500 MW for up to twelve dispatch intervals in HE 14:00 through 16:00 (between 1:00 and 4:00 p.m.). This created the price spike discussed in further detail in the Real-Time Market section. The following chart compares hourly actual loads in May 2003 with those in May 2002. Despite high temperatures at the end of May, the average hourly load for the month was 25,191 MW, 0.8% lower than the 25,388 MW of May 2002.

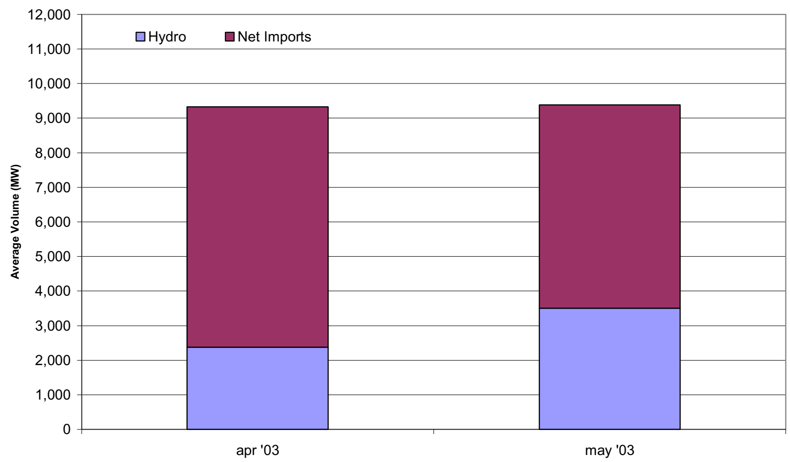
Figure 1. Hourly Actual Loads in May[2]



Warm weather and a near-normal snowpack in the Sierra Nevada has produced a robust snowmelt. Consequently, in-state hydroelectric production increased to 3,503 MW on average in May from 2,380 MW in April, while net imports decreased by an approximately similar amount, as shown in the following chart.

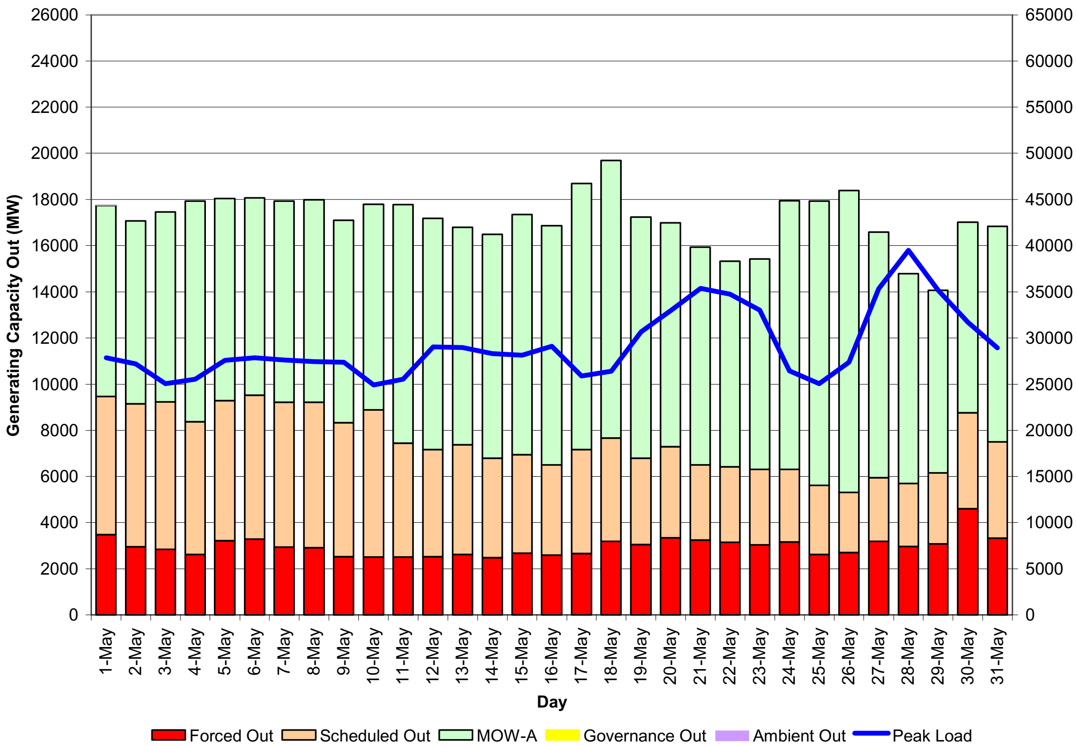
[2] Top-of-hour loads. May differ from instantaneous intra-hour loads.

Figure 2. In-State Hydroelectric Production and Net Imports April and May 2003



As loads increase, prices rise, and some units respond by voluntarily bidding into the market. In order to ensure that a sufficient level of resources is available to meet load, the ISO may also deny applications for must offer waivers. On May 28, the ISO declared a Stage 1 emergency, meaning that reserves had dropped below 7%. Low reserve levels caused the ISO to revoke many of the must offer waivers that had been issued. The high prices that ensued also attracted units with planned outages back into the market. Since that time, the levels of economic outages (must offer waiver) and planned outages in particular have fallen dramatically. The following chart shows daily average outages in May.

Figure 3. Daily Average Generation Outages in May



II. Real-Time Market Performance

Incremental (INC) and decremental (DEC) prices in the ISO's Balancing Energy Ex-Post Price Auction Market (the BEEP Stack) averaged $88.98 and $5.97/MWh respectively. This was a significantly larger spread than that seen in April, when INC and DEC prices averaged $66.30 and $13.09/MWh. Volume was weighted heavily on the DEC side in May resulting in lower DEC energy prices. INC and DEC volumes respectively were 146 and 317 GWh in May, or hourly averages of approximately 198 and 430 MW, compared to 230 and 255 MW in April.

The high INC price of $88.98/MWh is due primarily to the effect of price spikes. In the first half of the month, prices routinely spiked in HE 23:00 (10:00 to 11:00 p.m.), a phenomenon noted in previous monthly reports, as grid balancing becomes difficult following the end of peak-hour bulk power contracts at 22:00 (10:00 p.m.) In addition, the price spike on the afternoon of May 28 had a significant impact on the monthly average price, as approximately 10.8 percent of the month's incremental energy was procured during that five-hour period.

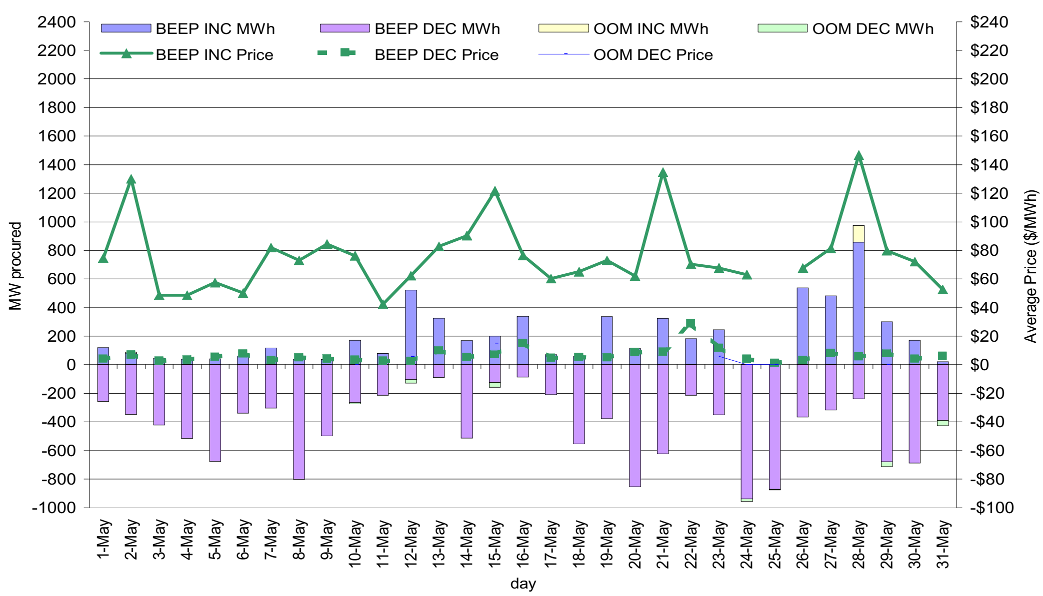
The following table shows real-time prices and volumes, average system loads, and percent underscheduling in May.

Table 1. Real-Time Average Prices and Total Volumes, System Loads, and Underscheduling in May

	Avg. BEEP Price and Total Volume		Avg. System Loads
	Inc	Dec	
Peak	$ 88.53	$ 7.97	27,221 MW
	126 GWh	209 GWh	
Off-Peak	$ 87.31	$ 1.64	21,132 MW
	20 GWh	108 GWh	
All Hours	$ 88.36	$ 5.81	25,191 MW
	146 GWh	317 GWh	

The following chart shows daily average BEEP volumes and prices and out-of-market (OOM) volumes for May 2003.

Figure 4. BEEP Prices and BEEP and OOM Volumes in May

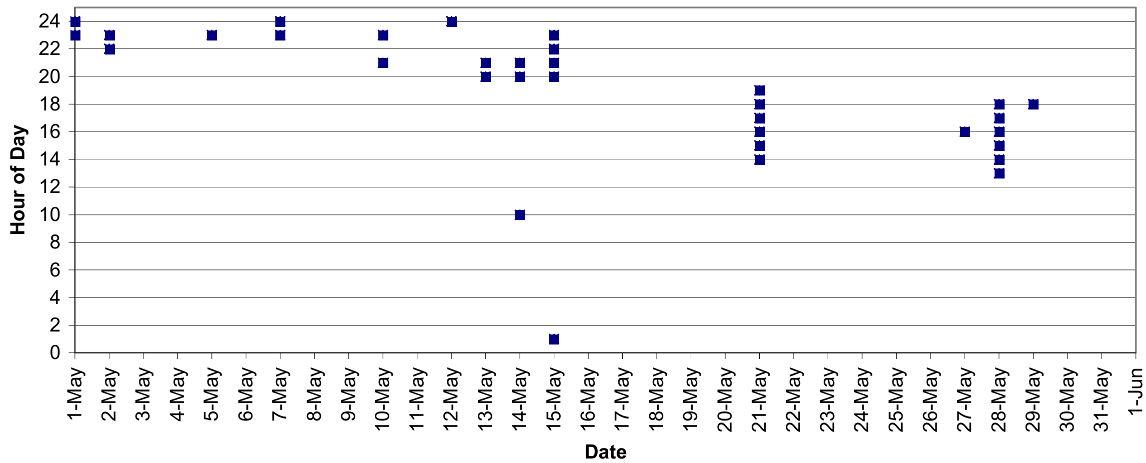


Price Spikes.[3] The real-time energy markets produced near competitive results in May. However, as noted, late evening price spikes have been characteristic of the real-time market over the last several months. These have been particularly prevalent in HE 23:00 (between 10:00 and 11:00

[3] For this analysis, a price spike is defined as anytime the price exceeds $100/MWh.

p.m.). Their frequency has been significantly reduced since mid-May. Late-evening spikes in which the BEEP hourly average market-clearing price was at least $100/MWh occurred in nine of the first 16 days of May; six of those days included a spike in the HE 23:00 hourly price. The last observed spike in HE 23:00 was on May 16. The following chart shows hourly price spikes in May by the hour of day they occurred.

Figure 5. Hourly Price Spikes by Hour of Day in May



The movement in spikes away from late evening hours is due in large part to the seasonal shift in the peak load to afternoons and away from late evening hours. With warmer weather, the evening load drop-off is smoother, enabling the ISO to dispatch fewer resources to maintain system balance.

Spikes in May with cost impacts are as follows:

During HE 22:00 on May 2 the price hit $104.75/Mwh as a generator was dispatched for its minimum run time of a full operating hour in response to a resource deficiency related to the phenomena we have seen in HE 22:00 in recent months.[4] The market impact of this spike, defined as the cost above that of the same volume dispatched at the monthly average price, was approximately $97,000.

On May 15, the price ranged between $114.71 and $174/MWh from 7:50 p.m. to 11:00 p.m. The price was set by a number of different generators. At 6:45 p.m., an incident at the Sylmar substation just north of Los Angeles caused a derating of the Pacific DC Intertie (NOB), necessitating that the ISO skip import bids on that path. This curtailment contributed to congestion on Path 26, resulting in the ISO pricing SP15 separately from NP15. Beginning HE 21:00 (8:00 to 9:00 p.m.), the ISO dispatched all available resources in SP15. In HE 21:00 and then again in HE 23:00, the ISO skipped energy bids from Ancillary Services to conserve reserves, which fell below the requirement of 7 percent of load. In an effort to ensure reliability, the ISO denied at least one

[4] See Market Analysis Report for April 2003 for an explanation of the causes of late evening price spikes.

request to be waived from the “Must-Offer” Obligation through HE 24:00. The market impact of this spike was approximately $160,000.

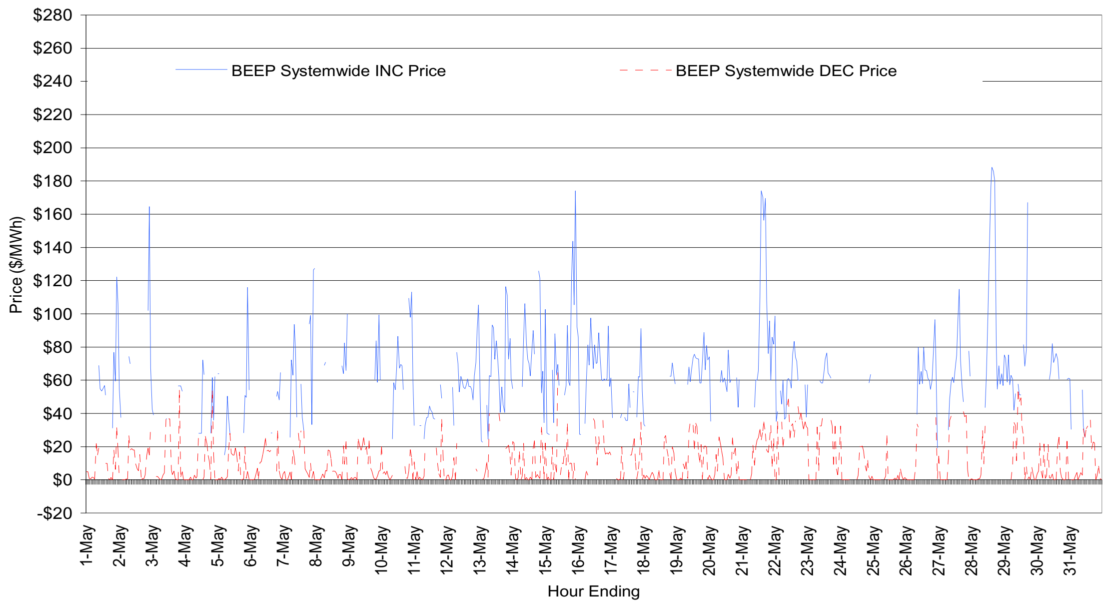
On the afternoon of May 21, from 1:40 to 6:40 p.m., the price spiked in SP15 as north-to-south transmission on Path 15 reached its capacity and the BEEP Stack was split to price zonally. The volume dispatched in SP15 averaged 959 MW, and reached a peak of 1,548 MW. The peak price of $174/MWh persisted for four hours, set by a single unit. Beginning HE 15:00, the ISO skipped energy bids from AS to conserve operating reserves, and dispatched peaking resources in SP15 to meet the imbalance demand. The market impact of this spike was approximately $400,000.

On May 27, from 2:50 to 4:00 p.m., the price spiked as several units were dispatched for their minimum-run periods of one hour, while the ISO skipped AS bids to conserve operating reserves. These units set the MCP in the range of $125.30 to $126.91/MWh. The estimated market impact of this spike was $115,000.

On May 28, an unexpected heat wave in California resulted in insufficient scheduling of forward electricity to meet actual load. This, in addition to a constraint on imports from the Pacific Northwest and the loss of over 500 MW of generation in Southern California, resulted in the ISO calling a Stage 1 Resource Deficiency emergency between 3:00 and 8:00 p.m. These conditions produced a price spike that persisted for over five hours, from 12:40 to 6:00 p.m. During this period, real-time dispatched volume averaged 3,000 MW, and peaked in HE 14:00 interval 6 (from 1:50 to 2:00 p.m.) at approximately 4,200 MW. The BEEP price averaged $170.22 and peaked at $191.32 between HE 16:00 interval 3 and HE 17:00 interval 3 (from 3:20 to 4:30 p.m.). The estimated market impact of the spike was $1.6 million.

The following chart shows BEEP hourly average prices in May.

Figure 6. Real Time Incremental and Decremental Prices in May



Out-of-Sequence Procurement. There was a total of 5,821 MWh of incremental energy called out-of-sequence (OOS) in May. The average price paid was $68/MWh resulting in a re-dispatch premium above the market clearing price of approximately $60,000. Most of these calls were necessitated by congestion either at the Vincent substation or due to the Southern California Import Transmission nomogram (SCIT), a constraint that limits the amount of energy that can be imported into Southern California at any given time. On the decremental side, 740 MWh of energy was dispatched OOS. Generators paid an average of $2/MWh to the ISO to reduce production, for a gross payment of $1,485. This resulted in a re-dispatch premium of $50,806 from the market clearing price. These calls were necessitated by a series of line outages and maintenance work.

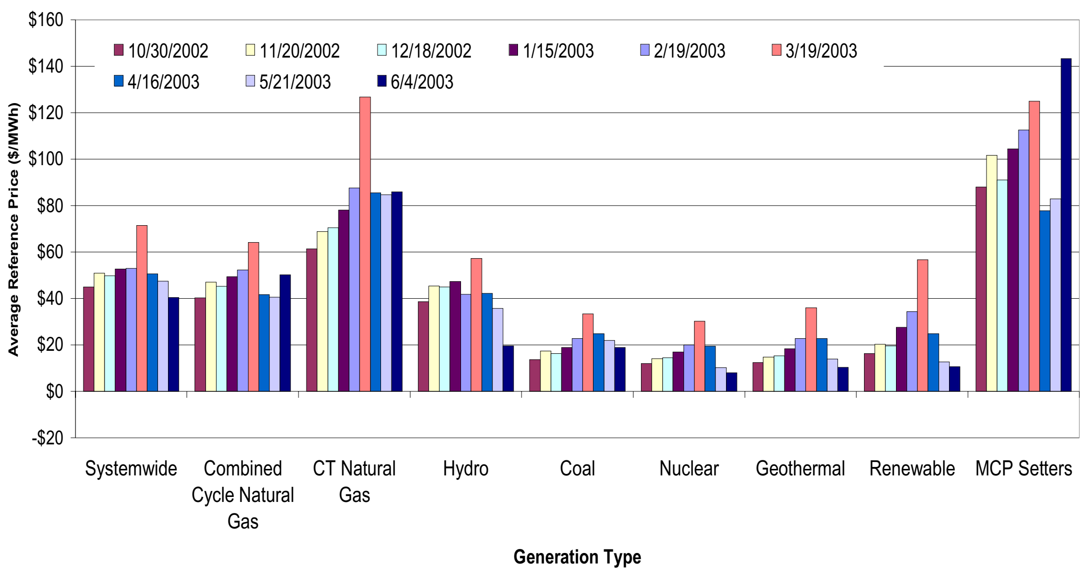
Out-of-Market Procurement. On the incremental side there was a total of 2,752 MWh of energy procured out-of-market (OOM) in May, at a gross cost of $383,935, and an average price of $140. Nearly all of this energy was procured on May 28 when a Stage 1 emergency was declared, and problems with the load forecast resulted in significant underscheduling by Load Serving Entities. This resulted in operators dispatching all available energy in the BEEP stack and forcing them to procure additional energy out-of-market to balance the system.

On the decremental side there was a total of 3,995 MWh of energy procured decrementally from out-of-state suppliers at an average price of $39/MWh, resulting in a payment to the ISO of $156,046. Nearly all of the decremental OOM procurement was due to persistent overgeneration. The overgeneration was particularly problematic during the morning ramp-up (6 AM to 9AM), and occasionally during the evening ramp-down (9PM – 11PM), when peak-hour contracts cycle on and off.

Performance of Automated Mitigation Procedures (AMP). Bidders failed the AMP Conduct Test in 131 distinct hours in May, compared to 33 hours in April. There still have not yet been any violations of the AMP Impact Test since it was implemented in October. Both the Conduct and Impact test thresholds must be violated for bid mitigation to occur.

Since October 2002, DMA has monitored trends in reference levels, both in absolute terms, and, for gas-fired units, normalized to account for changes in the price of natural gas. Non-normalized reference levels peaked in March, due to a spike in gas prices at that time. While prices softened from April through mid-May on a system-wide basis, certain units' reference levels have increased in the recent few weeks. Those units' high bids have been called on during intervals in which the real-time price has been high. The following two charts show the trend in average reference levels since AMP was implemented in late October. As shown in the charts, while average reference levels for most types of generation units have increased since October, they have decreased on a gas-normalized basis.[5] In addition, the index of reference levels of units that have consistently been able to set the price in recent months[6] ("MCP Setters") reached an all-time high when not adjusted for gas price changes, and nearly reached its high even when adjusted for gas price changes as shown in figures 7a and 7b.

Figure 7a. Average Reference Levels by Generation Type, Not Adjusted for Changes in Gas Prices



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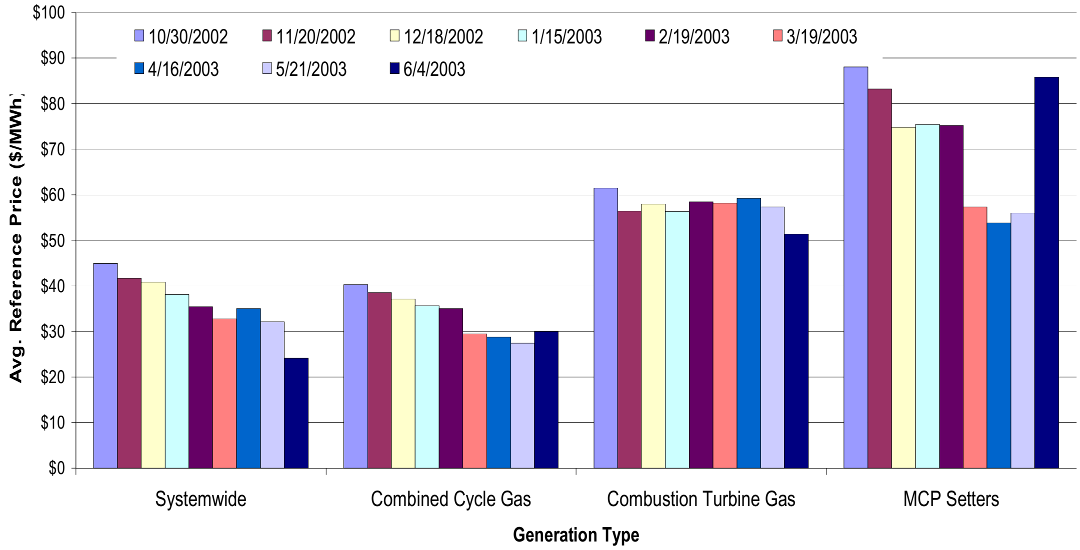
[5] Reference levels for gas fired thermal units are adjusted monthly to reflect changes in natural gas prices.
[6] The "MCP Setters" index includes all units that set the BEEP market-clearing price in at least 15 ten-minute pricing intervals between May 1 and June 8, 2003.

Figure 7b. Average Reference Levels by Generation Type for Gas-Fired Generation, Normalized to October 2002 Gas Prices



III. Ancillary Services Market Performance

Prices for upward and downward regulation and spinning reserves continued their upward trend that has persisted since the winter season. Increases in May were substantially sharper than those in April. Procured volumes of regulation up, regulation down, spinning reserves and non-spinning reserves remained steady or declined slightly, while bid volumes continued to decrease before picking up again toward the end of the month. In late May, the trend in the prices of those services shifted from increasing to decreasing. However average prices were still greater during the latter half of May than in April. Discussion of this trend follows the pricing summary.

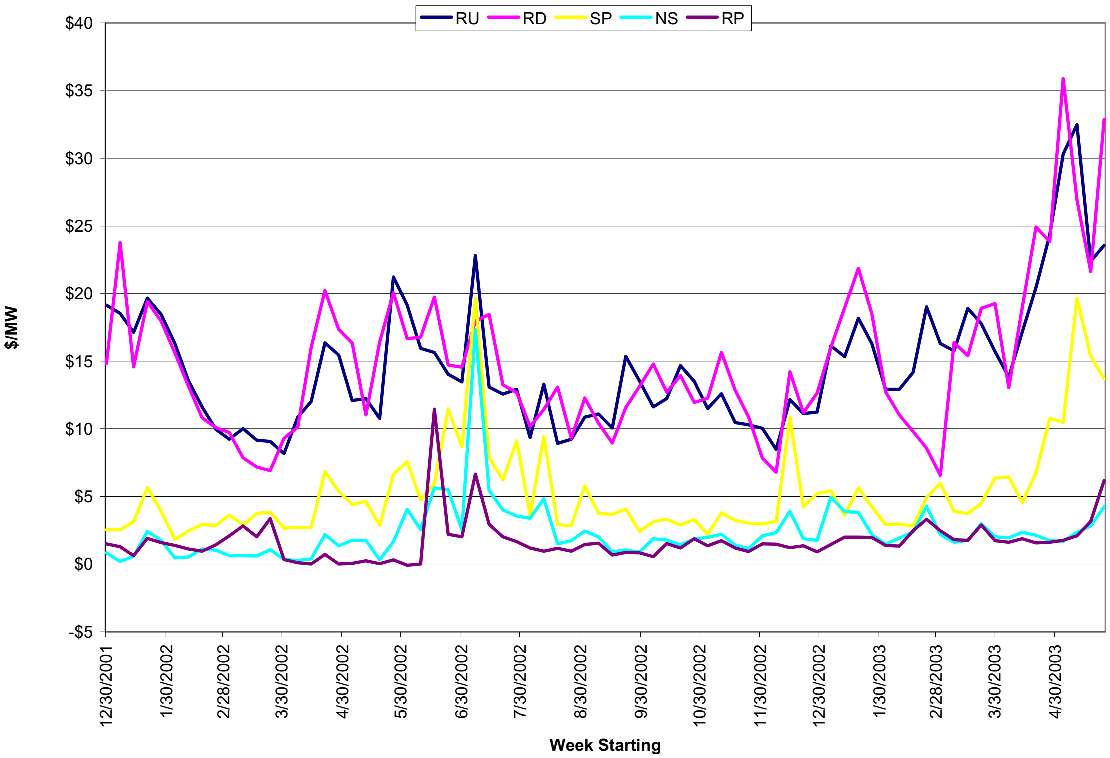
The volume-weighted average price of upward regulation (RU) was $28.04/MWh in May, up 56% from $17.99/MWh in April. The average price of downward regulation (RD) was $29.31/MWh in May, up 46% from $20.13/MWh in April. The average spinning reserve (SP) service price was $14.07/MWh in May, 116% higher than the average price of $6.51/MWh in April. The non-spinning reserve (NS) service price averaged $2.57/MWh, up slightly from $2.10/MWh in April. The average cost of procuring ancillary services rose 61% on approximately constant demand.

Table 2. Average AS Prices and Volumes by Market in May

	Day-Ahead Market	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$ 26.90	$ 40.79	$ 28.04	335	30	92%
Regulation Down	$ 28.78	$ 33.69	$ 29.31	347	42	89%
Spin	$ 14.19	$ 11.89	$ 14.07	644	38	94%
Non-Spin	$ 2.52	$ 3.50	$ 2.57	645	39	94%
Replacement	$ 3.11	$ 5.32	$ 3.17	19	*	98%

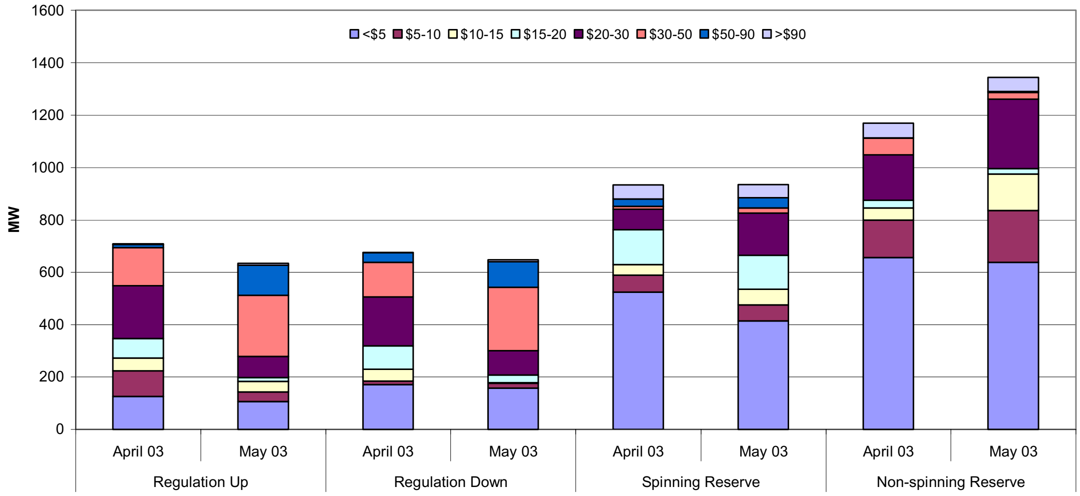
The following chart shows weekly average prices for ancillary services over the most recent eighteen months. This chart shows a seasonal trend toward price increases in these products during late April and early May. We saw the same sort of price increase in April and May of 2002. However in 2002 prior to the April/May price increases, there was a significant decrease in regulation prices leading up to the April/May increase. In 2003, regulation did not experience any such fall in prices during this period. Thus, price levels for May 2003 are significantly higher than those in May 2002 on average.

Figure 8. Weekly Average Prices for Ancillary Service Markets December 2002 - May 2003



The following chart compares the monthly average bid composition for each ancillary service in April and May. For Regulation Up, Regulation Down and Spinning Reserves, a noticeable decrease in average bids and bid compositions skews toward higher prices in May than in April. Non-spinning Reserves show increased bid volumes on average with a slight skew toward higher prices. As noted previously, average demand remained approximately constant between April and May.

Figure 9. Comparison of A/S Bid Composition: April 2003 vs. May 2003



Average hourly RU bid volume was 635 MW in May, significantly lower than the 708 MW in April. The percentage of RU bids awarded increased from 52 percent in April to 58 percent in May. Average hourly volume of bids with prices below $15/MWh was 275 MW in April, compared to 184 MW in May.

Decreasing bid volumes for Regulation Down (RD) with consistent demand resulted in higher prices for RD. The average hourly Regulation Down (RD) bid volume was 648 MW in May, significantly lower than the 676 MW seen in April. Bids below $15/MWh accounted for 245 MW bids in April, compared to 178 MW in May.

In periods in which the price for an AS market exceeded $75/MW in May, 90 percent of the units certified for the service did not bid into the market. Roughly 60 percent of certified units were offline, either experiencing an outage or without forward schedules. Units that were online were frequently generating at maximum capacity (about 23% of instances in which the unit was online – 9.1% of the time overall), which precludes provision of regulation up and can hinder provision of regulation down.[7]

The number of units not involved in the ancillary service markets during price spikes points to three contributing factors to the thinness of the regulation bid stacks. One of those factors is outages, which largely contributed to the lack of certified units available to provide such services. During May, the total capacity not available due to planned outages declined dramatically as the maintenance season ended. Weekly bid sufficiency improved for both upward and downward regulation services later in May. Decreasing outages of regulation-certified units should lead to

[7] Percentages are based upon numbers of instances, rather than total volumes, of services removed from the market.

increased bid sufficiency in these markets. Regulation-certified units not committed for reasons other than outage was the second factor in regulation bid stack thinness. System demand has increased over the course of May, bringing more generation online. This has resulted in increased peak hour regulation bids from combined cycle and other thermal units. However as demand increases, so does the likelihood of the third contributing factor: units generating at maximum capacity. Among the online regulation-certified units, this was a significant factor limiting ancillary services market competitiveness in May. Under increasing load, many units may become available to bid into the regulation markets; however regulation-certified units will also be more likely scheduled at maximum capacity. The balance between these factors may yield only marginal gains in competitiveness through the summer.

The Spinning Reserve market also experienced average price increases. During the same period, SP bid sufficiency actually improved slightly over April. SP bids averaged 934 MW in April and 935 MW in May. Coupled with stable demand (686 MW average in April, 681 MW average in May), the price increase in SP is attributed to the trend toward higher bids associated with similar volumes. Bids below $15/MW decreased 93 MW from 628 MW to 535 MW.

Prices have risen substantially, due largely to the increased dependency on combustion turbines for providing SP. As hydroelectric generation increased in May, less hydro capacity was available for spinning reserves. In a review of hours in which the price of SP was greater than $40/MW in the Day-Ahead market, combustion turbine bids into the Spin Market were higher than average while at least two of three other categories of bids (hydroelectric, combined cycle and non-gas thermal) bids were substantially below average. Another factor in increasing SP prices was the gradual increase in electricity load, which led to increasing demand for SP toward the end of May. Furthermore, the weather that prompted the Stage 1 Emergency on May 28 resulted in unusually high hour-ahead prices – above $80/MW – for the evening of May 28 and the afternoon of May 29 along with greater than average volumes procured.

Table 3. A/S Bid Volume vs. Demand

	Average Bid Volume (MW)	Average Demand (MW)	Percent Awarded
Regulation Up	635	367	58%
Regulation Down	648	389	60%
Spinning Reserve	935	681	73%
Non-spinning Reserve	1344	683	51%

IV. Interzonal Congestion

Interzonal congestion costs totaled nearly $4 million in May, the highest monthly total since July 2002. Nearly $3 million of those costs were due to congestion on Path 26 in the North-to-South direction. All other congestion costs occurred mostly in the import direction. COI, NOB, and LUGOTMONA each incurred congestion costs of $514,000, $340,000, and $119,000, respectively.

The costs on Path 26 were directly associated with the significant congestion that occurred during peak hours throughout the month. The combination of hydro production in the Pacific Northwest and high demand in southern California resulted in congestion on Path 26 in the North-to-South direction in many peak hours. Throughout most days in the month, Path 26 was available in its full capacity, except for a few hours on May 29 and 31, when it was derated pursuant to an import constraint in the wake of problems on the Midway-Vincent #3-500kV Line.

COI and NOB experienced derates in May as well. COI, which was derated as much as 1,400 MW, incurred most of its congestion costs during those derates. On May 20 and May 31, the day-ahead congestion prices briefly exceeded $50/MWh. Most of the congestion costs on NOB were incurred in the last few days of the month; also due in part to line derates. The highest day-ahead congestion price on NOB of approximately $11/MWh was reported on May 29.

Table 4. Interzonal Congestion Frequencies and Prices

			DA			HA		
Branch Group	**Direction of Cng.**	**Peak/Off-Peak Hours**	**No. of Cngs. Hours**	**Pct of Hours Being Cng.**	**Avg Cng. Price ($/MWh)**	**No. of Cngs. Hours**	**Pct of Hours Being Cng.**	**Avg Cng. Price ($/MWh)**
COI	IMPORT	ON-PEAK	142	29%	3.73	38	8%	5.94
ELDORADO	IMPORT	OFF-PEAK		0%		1	0%	77.00
MEAD	IMPORT	OFF-PEAK		0%		1	0%	24.98
NOB	IMPORT	ON-PEAK	134	27%	1.51	49	10%	19.47
PALOVRDE	IMPORT	ON-PEAK	7	1%	2.00	22	4%	44.02
PALOVRDE	IMPORT	OFF-PEAK		0%		2	1%	93.89
SUMMIT	IMPORT	ON-PEAK	3	1%	0.25		0%	
IID-SDGE	EXPORT	ON-PEAK	16	3%	30.00		0%	
PATH15	N->S	ON-PEAK	2	0%	0.02	2	0%	2.50
PATH26	N->S	ON-PEAK	235	47%	6.17	82	17%	16.13
PATH26	N->S	OFF-PEAK	12	5%	5.71	3	1%	31.29

Table 5. Inter-zonal Congestion Costs

Branch Group	Day Ahead Congestion Costs Import	Day Ahead Congestion Costs Export	Hour Ahead Congestion Costs Import	Hour Ahead Congestion Costs Export	Congestion Costs Import	Congestion Costs Export	Total Congestion Costs
COI	$504,113	$0	$9,421	$0	$513,535	$0	$513,535
ELDORADO	$0	$0	$0	$0	$0	$0	$0
IID-SCE	$0	$0	$0	$10,381	$0	$10,381	$10,381
IID-SDGE	$0	$29,774	$0	$0	$0	$29,774	$29,774
LUGOTMONA	$119,423	$0	$0	$0	$119,423	$0	$119,423
MCCULLGH	$0	$0	$0	$1	$0	$1	$1
MEAD	$0	$0	$0	$0	$0	$0	$0
NOB	$340,452	$0	$524	$0	$340,976	$0	$340,976
PALOVRDE	$29,078	$0	$2,974	$0	$32,053	$0	$32,053
PATH15	$0	$5	$0	$914	$0	$919	$919
PATH26	$0	$2,890,012	$0	$56,619	$0	$2,946,631	$2,946,631
SUMMIT	$23	$0	$0	$0	$23	$0	$23
Grand Total	$993,089	$2,919,791	$12,920	$67,914	$1,006,009	$2,987,706	$3,993,715

V. Firm Transmission Rights Market

FTR scheduling. On some paths, FTRs were used to establish the scheduling priority in the day-ahead markets. As shown in the following table, a high percentage of FTRs was scheduled on some paths (88% on Eldorado, 94% on LOGOIPPDC, 96% on Palo Verde, 97% on Silver Peak in the import direction, and 50% on Path 26). FTRs on those paths are mainly owned by Southern California Edison Company (SCE1) and municipal utilities.

Table 6. FTR Scheduling Statistics for April, 2003

Branch Group	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% FTR Schedule
COI	IMPORT	745	269	610	500	36%
ELDORADO	IMPORT	510	448	510	510	88%
IID-SCE	IMPORT	600	334	385	385	56%
LUGOIPPDC	IMPORT	370	348	354	225	94%
LUGOTMONA	IMPORT	167	89	96	56	53%
LUGOWSTWG	IMPORT	93	33	46	28	36%
MEAD	IMPORT	516	55	211	150	11%
NOB	IMPORT	686	192	318	100	28%
PALOVRDE	IMPORT	627	603	625	600	96%
SILVERPK	IMPORT	10	10	10	10	97%
VICTVL	IMPORT	991	14	64	64	1%
PATH26	EXPORT	1,425	1,291	560	717	50%

*only those paths on which 1% or more of FTRs were attached are listed.

** The FTRs on these paths were awarded to municipal utilities that converted their lines under the ISO operation and there were not released in the primary auction.

FTR Revenue per Megawatt. The following table summarizes the FTR revenue collected in May. Due to significant congestion on Path 26, FTR revenue per MW in the north to south direction reached $1,500/MW. FTR revenues on several other paths were also significant, especially on COI, LOGOIPPDC, NOB, and IID-SDGE where FTR revenues exceeded $200/MW.

Table 7. FTR Revenue Per MW ($/MW)

Branch Group	Direction	Apr	May	Cumm. Net REV	Pro-rate Annual FTR Rev*	FTR Auction Price
BLYTHE	IMPORT	$69	$0	$69	$412	$5,460
COI	IMPORT	$723	$536	$1,300	$7,801	$19,828
LUGOIPPDC**	IMPORT	$272	$0	$272	$1,631	N/A
LUGOIPPDC**	IMPORT	$0	$715	$715	$4,290	N/A
LUGOWSTWG**	IMPORT	$3	$0	$3	$20	N/A
MEAD	IMPORT	$166	$0	$166	$995	$7,820
NOB	IMPORT	$249	$203	$453	$2,718	$12,245
PALOVRDE	IMPORT	$233	$15	$249	$1,493	$88,167
SUMMIT	IMPORT	$108	$0	$108	$650	$650
IID-SDGE	EXPORT	$0	$480	$480	$2,880	$182
PATH15 **	N->S	$0	$5	$5	$30	N/A
PATH26	N->S	$1,147	$1,500	$2,716	$16,294	$8,602

*Pro-rate Annual FTR revenue is estimated based on the actual FTR revenue collected in this FTR cycle and assuming that FTRs would collect same rate of revenue in the remaining months of this FTR cycle.
** FTRs on these paths were awarded to municipal utilities that converted their lines to the ISO, and there were not released in the primary auction.

FTR After-Market Transactions. There were no trades in the secondary FTR market in May.

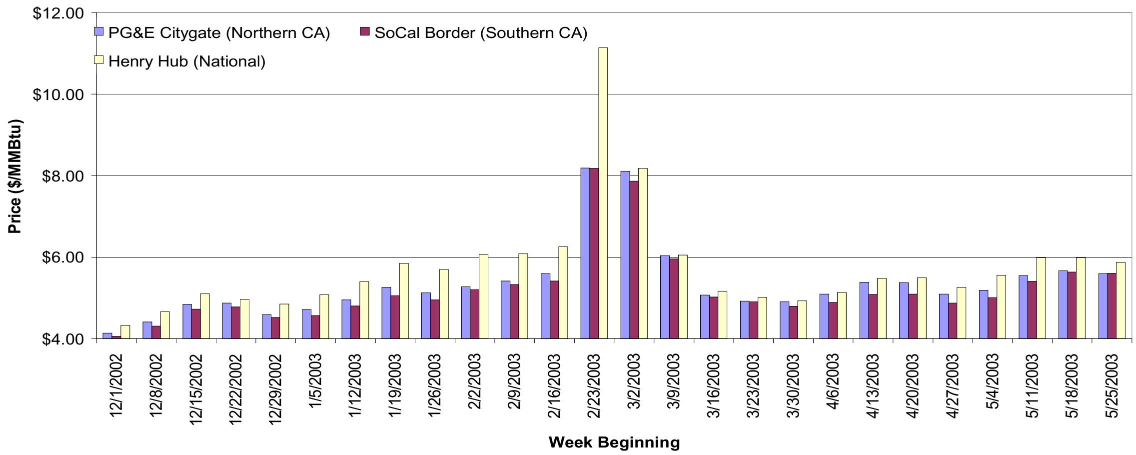
VI. Natural Gas prices

Throughout May, natural gas prices steadily increased in the West on expectations of increased cooling demand due to warm weather, particularly in the Southwest. Henry Hub prices began May at $5.32/MMBtu, peaked at $6.17/MMBtu, and closed the month at $5.98/MMBtu. PG&E Citygate prices began the month at $5.19/MMBtu, peaked at $5.84/MMBtu, and ended at $5.62/MMBtu. Southern California Border Average prices began the month at $4.94/MMBtu, peaked at $5.83/MMBtu, and ended at $5.71/MMBtu.

After slightly weaker prices during the weekend of May 3-4, prices increased with NYMEX Henry Hub futures prices due to EIA reports of a 57 billion-cubic-foot (Bcf) withdrawal of natural gas from storage in the prior week. The price increases continued steadily until May 15, after which prices declined by $0.20/MMBtu. Between May 18 and May 22, Southern California prices increased sharply to the monthly peak of $5.83/MMBtu due to increased cooling demand and warmer temperatures in the Southwest. After May 22, prices returned to the level of $5.45/MMBtu until

May 27, when high temperatures across California and in particular the Southwest, caused demand for cooling to increase sharply. Average bid week prices for June were $5.74, $5.25, and $5.75 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 16%, 10%, and 1% from May bid week prices. The following chart shows weekly average natural gas prices at California delivery points and at the Henry Hub national trading location.

Figure 10. Weekly Average Natural Gas Prices through May

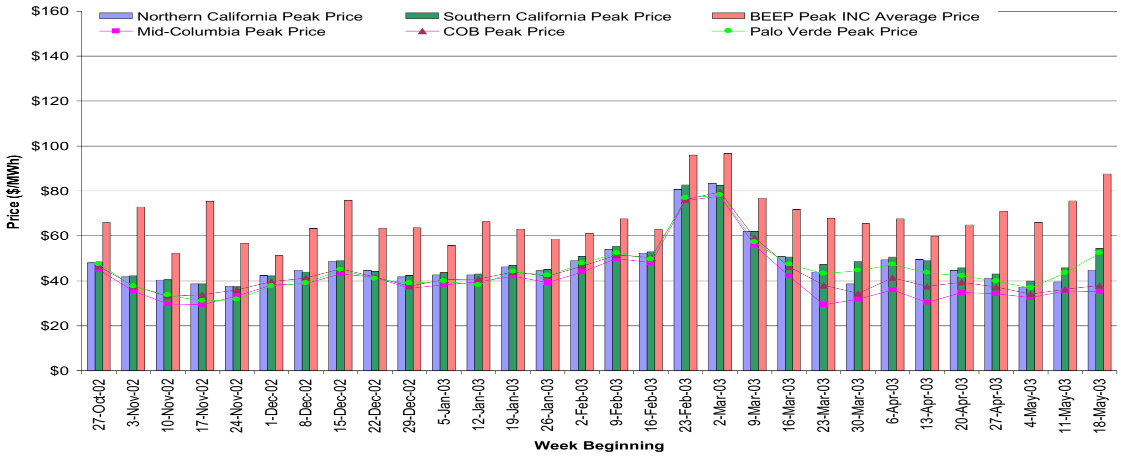


VII. Regional hub prices

Regional Day-Ahead electricity prices increased substantially in the latter half of May due to higher air conditioning demand in the Southwest. During the first week of May, Southern California prices remained steady at around $42/MWh; Mid-Columbia prices were flat at $34/MWh; and Northern California prices decreased from $43/MWh to $35/MWh on moderate temperatures in the North and ample supply of hydroelectric power. After the first week of May, prices increased until Southern California and Palo Verde prices exceeded $53/MWh, while Northwestern prices peaked at $47/MWh and returned to the $41/MWh level due to increasing Southwest temperatures. Additionally, after May 16, prices between Northern and Southern California diverged by nearly $10/MWh due to Path 26 transmission limitations.

Continuing high Southwestern temperatures and California-Oregon Inter-tie limitations during the third week of May caused Southern California and Palo Verde prices to exceed $60/MWh, while Northern California prices reached $50/MWh. Again, Path 26 constraints resulted in a $10/MWh price spread. The following chart shows regional bilateral peak contract prices at Western trading locations, and the average ISO real-time INC price.

Figure 11. Day-Ahead Bilateral Peak-Hour Electricity Contract Prices And ISO Real-Time INC Price



VIII. Issues under Review

FERC Investigations of Market Manipulation. The DMA Market Investigations staff has submitted a report to FERC staff summarizing additional analysis that has been done by the ISO on the various trading and scheduling practices outlined in the Enron memos. The report was prepared in response to a request from FERC staff for additional analysis that may be used in further investigation and disgorgement of profits from individual sellers, as recommended in the March 2003 FERC Staff Report.[8]

The staff report found that many trading strategies employed by Enron and other companies were undertaken in violation of market monitoring provisions of the Commission-approved tariffs of the ISO and California Power Exchange (PX), and recommended that the Commission initiate proceedings to require companies to disgorge profits associated with these tariff violations. The March 2003 FERC Report also recommends that certain participants identified in previous analyses submitted by the ISO to Commission Staff be directed to show cause why their behavior did not constitute gaming in violation of the ISO and PX tariffs. Following the release of the FERC Staff Report, Commission Staff also requested assistance from the ISO in developing updated analyses and transaction-specific data for individual participants whose behavior may constitute violations of the ISO and PX tariffs

Results summarized in this most recent ISO report vary from results in previous reports submitted by ISO Market Investigations staff for a variety of reasons:

- *Limited Time Frame*. Previous analyses by the ISO covered time period from 1998 through 2002. However, the March 2003 Staff Report indicates that any disgorgement of profits would only cover activities beginning in January 1, 2000 through June 21, 2001, and that

[8] *Final Report on Price Manipulation in Western Markets: Fact-finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, Docket No. PA02-2-00, March 2003 ("March 2003 Staff Report").

these disgorgements would be in addition to the refunds resulting from the California Refund Proceedings.

- *Additional Trading Practices*. Previous analyses by the ISO did not include a comprehensive analysis of the extent to which all market participants may have employed two of major trading practices outlined in the Enron memos: Overscheduling of load ("Inc'ing Load" or "Fat Boy"), and Ricochet (of "MW Laundering"). This report includes a more comprehensive analysis of these strategies.
- *Additional Information Provided by Participants.* Several market participants have contacted the ISO in order to offer explanations and/or correct data upon which previous analyses were based. This report incorporates the limited number of data corrections that have been identified to the ISO by participants and could be verified by the ISO.
- *Analytical Refinements/Corrections*. ISO Market Investigations staff has continued to verify and refine the computer programs used to identify market activity that may be reflective of the practices outlined in the Enron memos, and to quantify the potential financial impact of these practices. As part of this work, several refinements and corrections have been made to the computer routines used to perform these analyses.

In addition to the methodological descriptions and summary results presented in this report, Market Investigations staff is providing detailed data files identifying the specific transactions, schedules and metered data underlying this analysis. The staff is providing this data to allow further analysis and response to these results by Commission staff as well as individual market participants. Market Investigations staff has facilitated the dissemination of detailed information to individual participants, and has assessed and incorporated any additional information provided by participants as part of this process.

MD02. DMA continues to contribute to MD02 Phases Ib, II, and III design sessions.