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: May 30, 2003

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

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

Executive Summary

Real-time electricity prices moderated considerably on an overall basis due to lower real-time energy volumes and moderating regional short-term energy prices. Incremental (INC) and decremental (DEC) prices averaged $66.30 and $16.09 per megawatt-hour, respectively, with off-peak INC prices averaged slightly higher than on-peak prices, due to the HE 23:00 spikes. This has been caused by rapid changes in load and generation in the late evening hours between 10:00 and 11:00 p.m. following the end of sixteen-hour bilateral contract deliveries.

A derate of Path 26, a key transmission artery between Northern and Southern California, to 1400 MW from its full rating of 3000 MW persisted until April 4, following a fire at the Vincent Substation near Palmdale on March 21. In the first four days of April, this derate caused at least $1.65 million in Interzonal congestion management costs, in addition to $3 million in intrazonal congestion management costs due to out-of-sequence dispatches.

I. Electricity Market Trends through April 2003

Loads and Schedules. Due to unseasonably cool weather in April 2003, the monthly average load of 24,002 MW was 2.7 percent lower than in April 2002. The monthly peak load of 30,062 MW in April 2003 occurred on April 1 in hour ending (HE) 18:00, amid the heat wave that began March 31, and was nearly equal to that of April 2002. The chart below compares actual hourly loads in April 2002 and 2003, and is followed by an average hourly load profile for April 2003.

Figure 1a. Actual Hourly Loads in April[1]

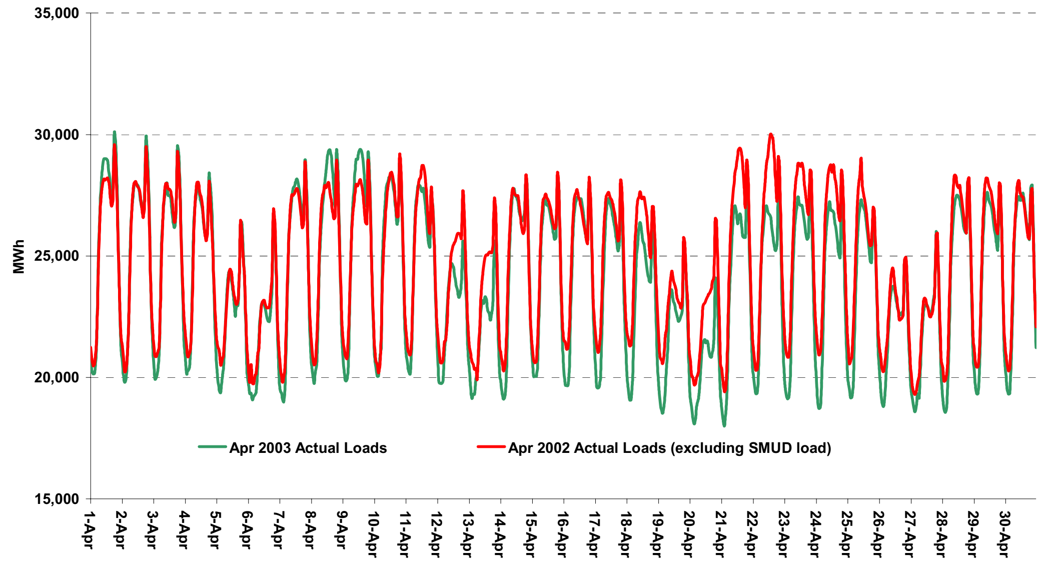
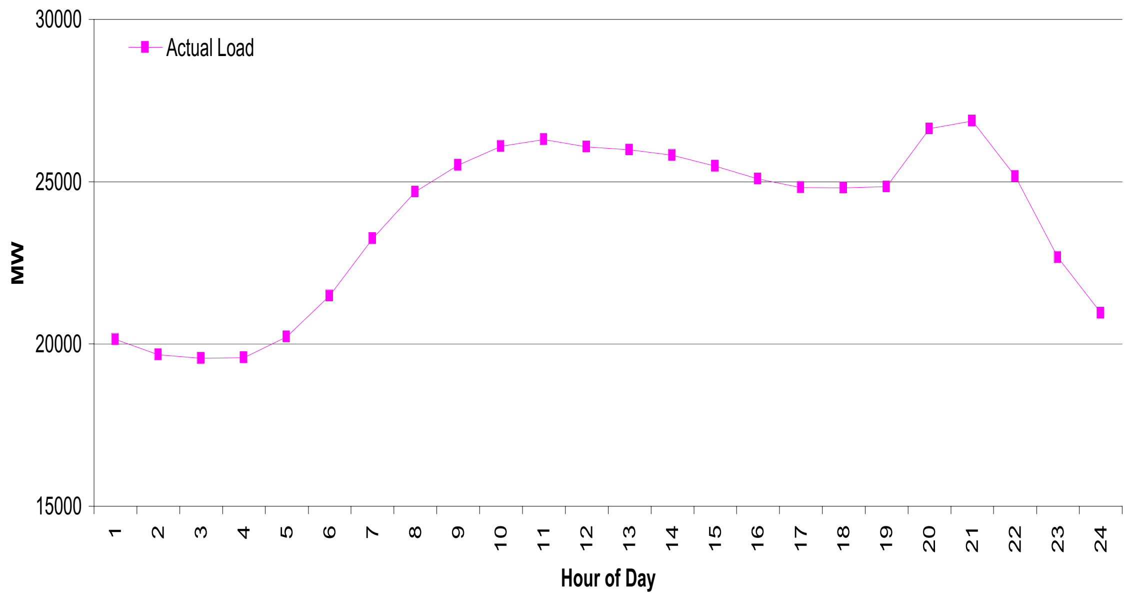


Figure 1b. Average Hourly Load Profile in April 2003

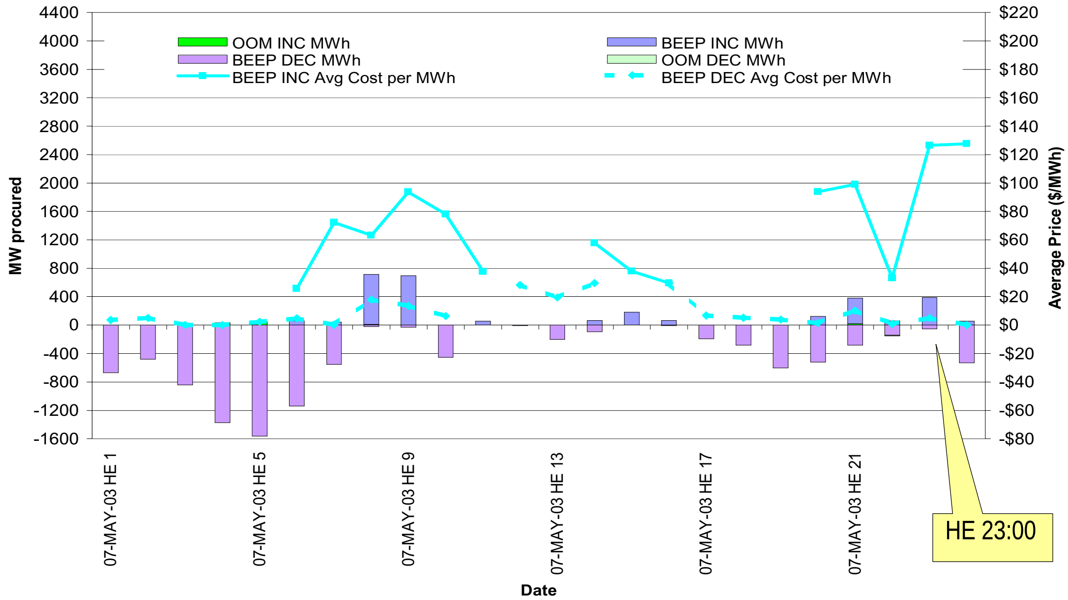


The rate of change in load from hour to hour and the corresponding rate of change in forward-scheduled energy create challenges for ISO operators to balance system loads and generation. This has become especially difficult during the late evening ramp, when loads drop at the rate of approximately 2,500 MW (10% of peak load) per hour beginning around 9:00 p.m. (HE 21:00). Since much of the forward schedules consist of 16-hour bilateral contract deliveries, which are relatively constant across hours but end abruptly at 10:00 p.m. (22:00), scheduled energy

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

decreases more quickly than load causing ISO operators to quickly increment generation in the real-time market to recover the imbalance. The result is price spikes at times for brief periods. This was the case on April 7, for which the real-time dispatch prices and volumes are shown in the following chart.

Figure 2. Real-Time Prices and Volumes: April 7, 2003



Hydro Conditions. Northern California received more precipitation in April 2003 than it has seen in any other April in several decades. This has helped to restore in-state hydro conditions to near-normal levels.

Imports and Exports. Net imports averaged 5,695 MW in April, down 9.3 percent from the March average and 17 percent from a year ago. A sharp decrease of 1,277 MW of actual imports on average was somewhat offset by a milder decrease of 694 MW of exports on average,[2] as low loads and heavy precipitation in California and relatively cool conditions which slowed the hydro runoff in the Pacific Northwest enabled utilities to draw from retained hydroelectric generation, in lieu of purchasing electricity at external trading hubs. The following chart shows imports and exports through April 2003.

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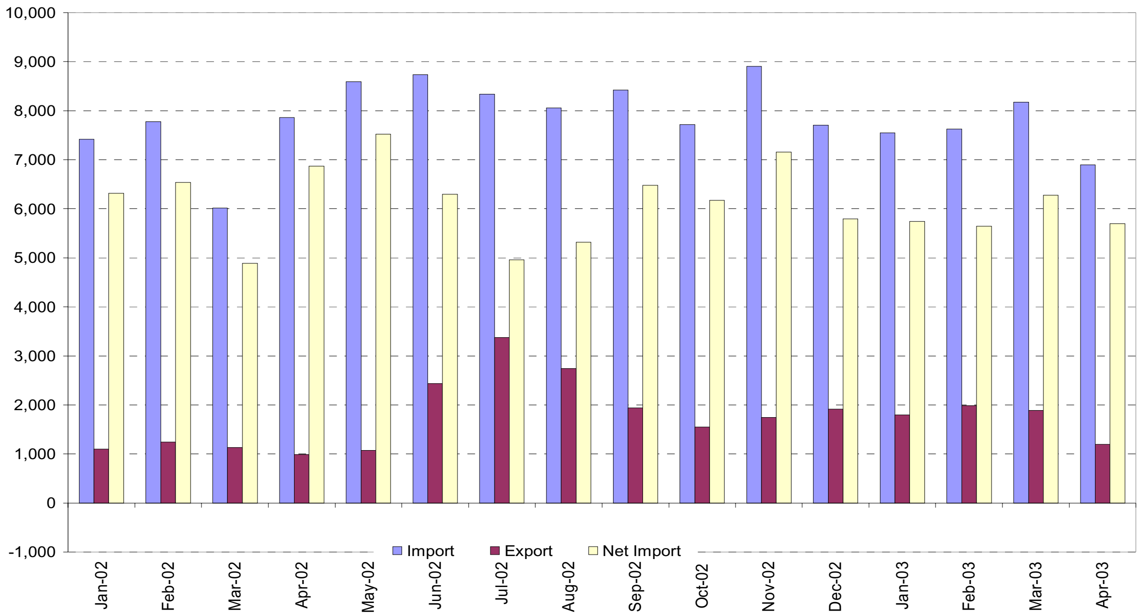
[2] Most exports are to the Sacramento Municipal Utility District (SMUD), which also has retained hydroelectric generation.

Figure 3. Imports and Exports through April 2003



II. Real-Time Market Performance

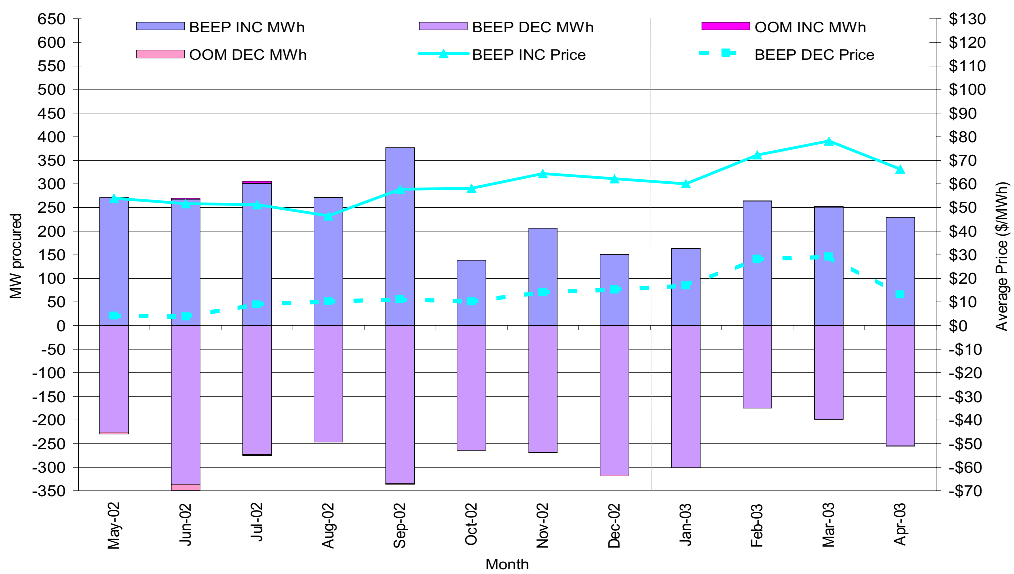
Incremental (INC) and decremental (DEC) prices in the ISO's real-time Balancing Energy Ex-Post Price auction market (the BEEP Stack) averaged $66.30 and $13.09/MWh in April, respectively, compared to $78.49 and $28.72/MWh in March. The decrease in incremental prices and decrease in decremental prices reflect in part the decrease in real-time incremental volumes and the increase in real-time decremental volumes. Real-time INC volume totaled 165 GWh in April, or an average of 229 MW, compared to an average of 252 MW in March. DEC volume totaled 184 GWh in April, or an average of 255 MW, compared to an average of 212 MW in March. The following chart shows real-time BEEP prices and volumes and average loads in April.

Table 1. Average Real-Time Prices, Volumes, and Loads in April

	Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW)
	Inc	Dec	
Peak	$65.94 127 GWh	$13.82 140 GWh	25,790 MW
Off-Peak	$67.51 38 GWh	$10.75 43 GWh	20,425 MW
All Hours	$66.30 165 GWh	$13.09 184 GWh	24,002 MW

The following chart shows monthly average BEEP volumes and prices and OOM volumes for the twelve months through April 2003.

Figure 4. Real-Time Volumes and Prices through April 2003



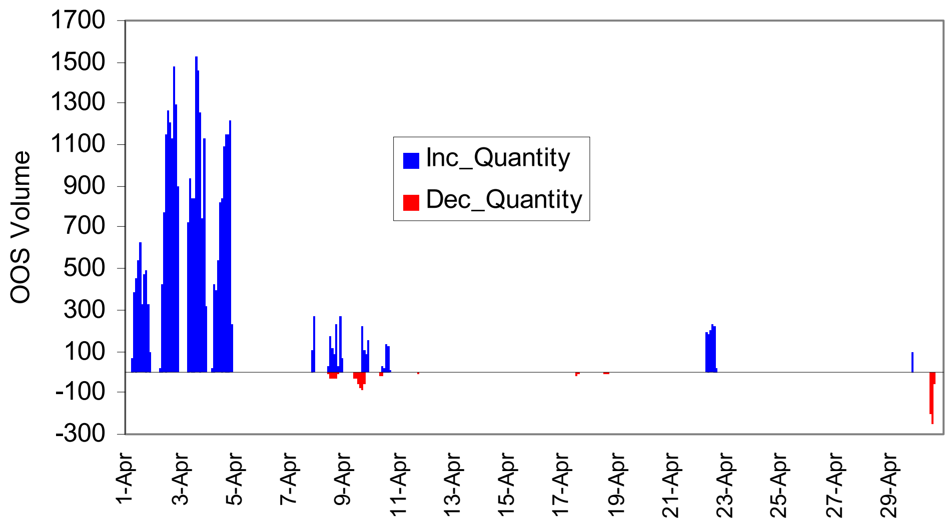
Out-of-Sequence Calls. The ISO procured approximately 55,000 MWh of energy in Out-of-Sequence (OOS) calls in April. Nearly all was dispatched as incremental energy to mitigate intrazonal congestion during the first few days of April, when Path 26 was below capacity following the Vincent substation fire on March 21. Supply delivered north-to-south on Path 26 overloaded either the Sylmar substation, or those transformers at Vincent that remain in operation. Consequently, units nearer to load were dispatched incrementally to meet load pull on those substations. On April 22, the ISO also made a series of incremental calls to several peakers to work around the North Gila-Hassayampa 500 kV line outage, which is part of the Palo Verde intertie linking Southern California and Arizona.

ISO operators made decremental OOS calls to manage congestion due to repairs on the Fulton-Santa Rosa #2 line and the Drum-Rio Oso #1 and #2 lines between April 8 and 11. Other decremental OOS calls on April 30 were necessary due to SCIT mitigation. The following table shows monthly total OOS energy, cost, and average cost to load in April. The chart below shows similar information by hour.

Table 2. Incremental and Decremental Energy OOS Calls, April 2003

	Quantity (MWh)	Gross Cost	Redispatch Cost	Average Price
DEC OOS	-1,387	-$39,003	$68,526	$28/MWh
INC OOS	54,932	$3,442,083	$2,058,474	$63/MWh

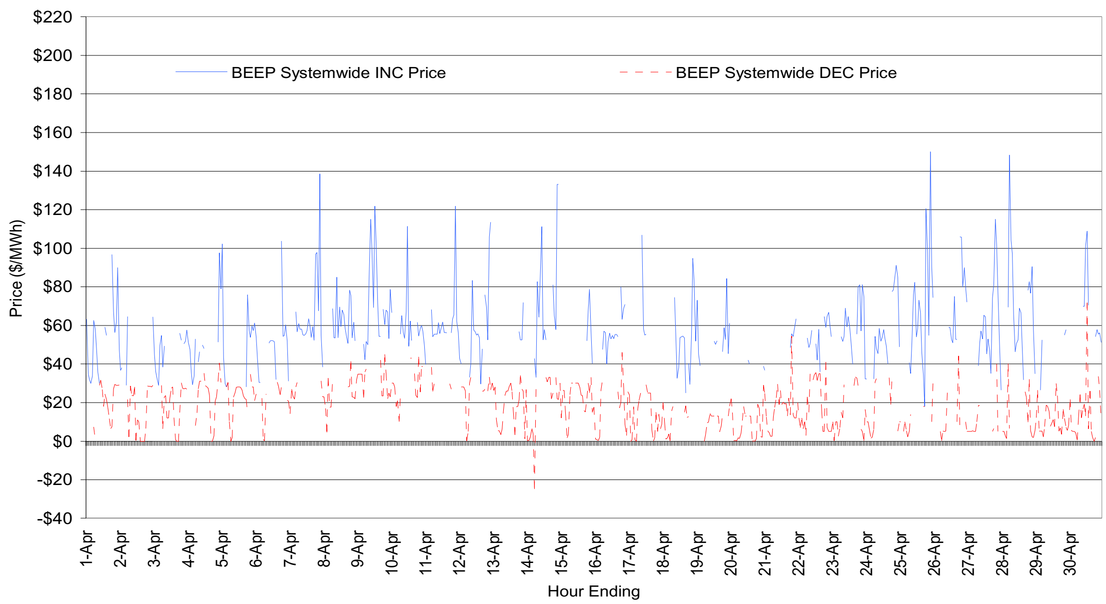
Figure 5. Hourly INC and DEC OOS energy, April 2003



Price Spikes. As noted above, several spikes occurred in April as schedules diverged from load, particularly in hour ending (HE) 23:00, the hour just after peak-hour bulk bilaterally contracted deliveries end at 10:00 p.m. As in March, ISO operators found it necessary to skip some available resources in favor of more expensive units due to operational constraints, causing spikes in the real-time market-clearing price on several occasions in April. Most of these instances involve skips of peaking resources, while others are skips of energy bids from ancillary services, which must be conserved during reserve deficiency periods. Still other spikes are due to combinations of these as well as other situations.

The following chart shows hourly average INC and DEC prices during hours in which there respectively were INC and DEC dispatch instructions in April.

Figure 6. INC and DEC Hourly Average Prices in April



On April 7, the hourly average price spiked to $138.63/MWh, increasing hourly market costs approximately $109,000 above the monthly volume-weighted average, as resources were skipped due to operational constraints. This occurred again on April 14, from 10:00 p.m. to midnight (HE 23:00 and 24:00), when the average INC hourly price spiked to a high of $133.09/MWh, for a market impact of approximately $16,000.

On April 9, peakers and resources from reserves were skipped to manage operational constraints and avoid a system reserve deficiency, causing the price to spike over several mid-day hours (HE 11:00, 14:00, and 15:00), reaching an hourly high of $121.93/MWh. The entire cost of the spike was roughly $134,000 above the monthly volume-weighted average. This also occurred on April 11 between 10:00 and 11:00 p.m. (HE 23:00), when the price was set at $135/MWh for a cost above average of approximately $28,000; and on April 25, also between 10:00 and 11:00 p.m., during which the hourly average price reached $150/MWh, for a market impact of approximately $56,000.

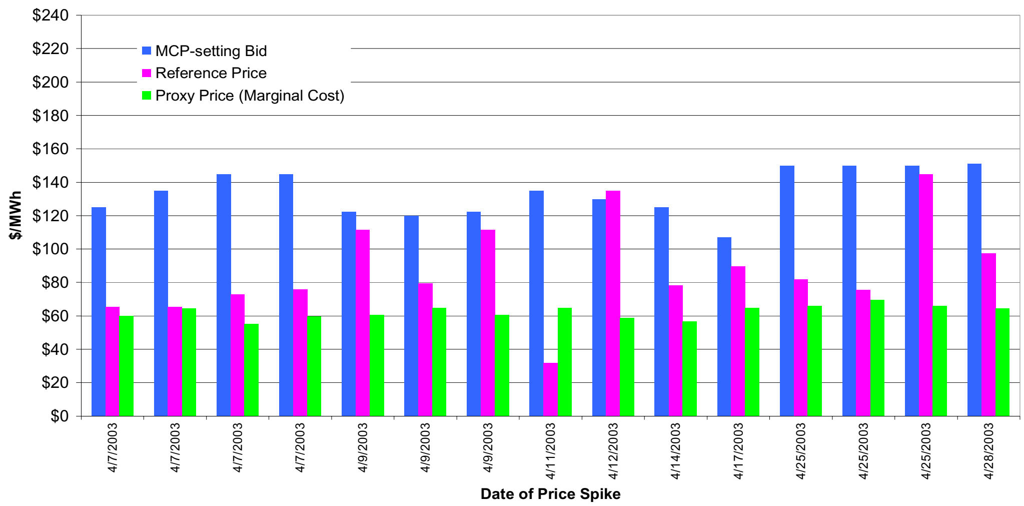
On April 14, from 6:00 to 7:00 a.m. (HE 7:00), the average DEC hourly price fell to -$24.84/MWh, as operators awarded decremental calls to counter the rapid generation ramp that occurred due to the beginning of peak-hour bilateral contract deliveries. This spike had a market impact of approximately $16,000.

On April 28, the INC price remained above $100/MWh from 6:30 to 8:40 a.m., peaking at $151/MWh. While the duration of the spike was twice that of most spikes seen lately, less energy than usual was dispatched in each interval, causing a market impact of approximately $66,000.

On April 30, the BEEP Stack was split between the NP15 and SP15 pricing zones due to congestion in accordance with the Southern California Import Transmission Nomogram (SCIT). Because imports into Southern California were constrained, a price of $125/MWh persisted in that region between 12:00 and 12:30 p.m. and between 1:40 and 2:00 p.m. as well.

The following chart shows ten-minute interval price spikes above $120/MWh in April, compared to the price-setters' marginal AMP reference prices and estimated marginal costs. As shown in the chart, two thirds of the price spikes were set by suppliers who bid significantly above their reference levels, yet still were within the generous AMP conduct test thresholds.

Figure 7. Price Spikes above $120/MWh in April 2003
With Price-Setters' Marginal Reference Prices and Estimated Marginal Costs



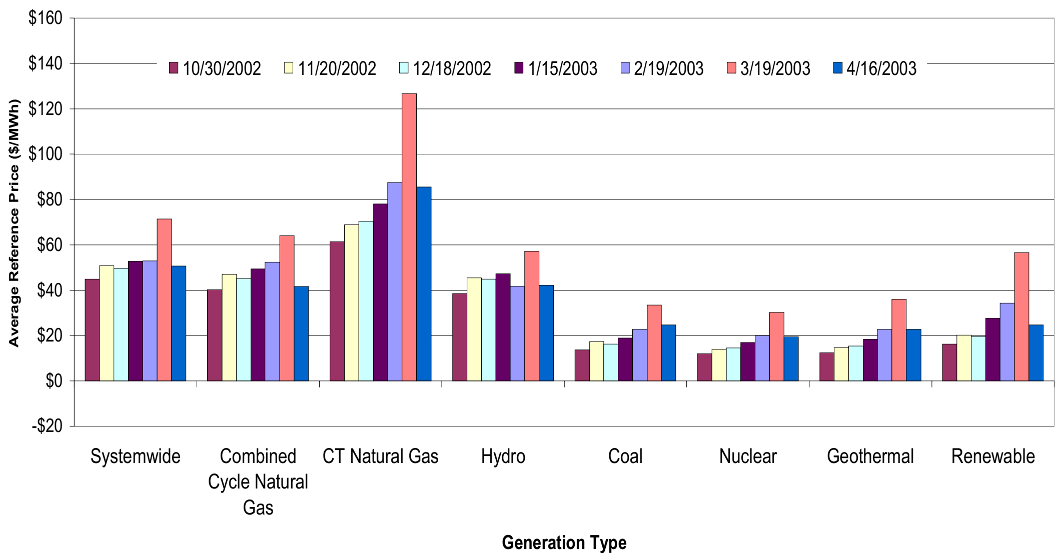
AMP Performance. Bidders failed the AMP Conduct Test in 33 distinct hours in April, compared to 135 hours in March. There have still not been any violations of the AMP Impact Test since it was implemented in October due to the generous thresholds. The following table shows Conduct Test failures by day in April.

Date	No. of Hours
4/4/2003	1
4/7/2003	5
4/8/2003	1
4/11/2003	1
4/12/2003	1
4/17/2003	1
4/19/2003	1
4/23/2003	3
4/24/2003	2
4/25/2003	4
4/26/2003	2
4/27/2003	4
4/28/2003	1
4/29/2003	2
4/30/2003	4

Since October 2002, DMA has monitored trends in reference levels. Reference levels are adjusted for changes in the price of natural gas. Thus, reference levels peaked in March due to a spike in gas prices during the bid week for March deliveries of gas, which actually occurred in the final week of February. In April, reference levels retreated to levels seen earlier in 2003. The March and April gas price deflators were $7.27 and $4.83/MMBtu, respectively.

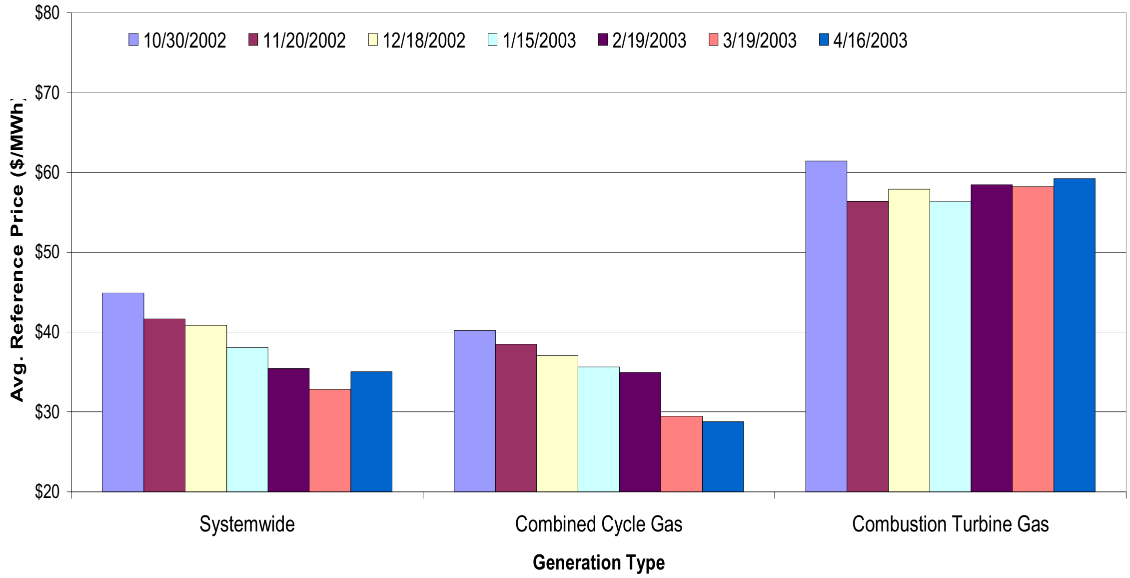
Non-gas-fired resources seldom set prices in the BEEP Stack. Because of the method used to calculate reference levels, they tend to inherit the reference levels of price-setting units.[3] The following charts show (a) average unadjusted reference levels by generation type; and (b) reference levels for thermal generators, normalized to the October 2002 gas price index. Although the normalized average reference levels for gas-fired generation has generally declined since AMP's implementation in October 2002, certain generators' reference levels have been systematically increasing as they consistently submit bids that are accepted at levels far in excess of their reference levels.

Figure 8a. Average Reference Levels by Generation Type, Not Adjusted for Changes in Gas Prices



[3] Specifically, reference levels of units that provide only forward-scheduled energy, or that provide real-time energy as price takers, are determined by taking 90-day volume-weighted moving averages of BEEP market-clearing prices (MCPs). These moving averages are adjusted for changes in gas prices. The BEEP MCPs are almost always set by gas-fired units.

Figure 8b. Average Reference Levels by Generation Type for Gas-Fired Generation, Normalized to October 2002 Gas Price



III. Ancillary Services Markets Performance

Average AS prices were relatively higher in April than in March for three of the five ancillary services, due to reduced bid volume and an increase in the share of higher priced bids. DMA is currently reviewing the reasons for these trends. Table 3 below shows average ancillary service prices and volumes by market in April.

Day-ahead and hour-ahead quantity weighted average price of upward regulation (RU) was $17.62/MWh in April, up slightly from $17.25/MWh in March. The average price of downward regulation (RD) was $19.82/MWh in April, up significantly from $14.91/MWh in March. The average spinning (SP) service price was $6.47/MWh in April, higher than the average price of $4.59/MWh in March. The non-spinning (NS) service price averaged $2.10/MWh, down slightly from $2.21/MWh in March.

Table 3. Average AS Prices and Volumes by Market in April

	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	$ 17.62	$ 22.11	$ 17.99	339	31	92%
Regulation Down	$ 19.82	$ 22.77	$ 20.13	360	43	89%
Spin	$ 6.47	$ 8.39	$ 6.51	669	16	98%
Non-Spin	$ 2.10	$ 3.26	$ 2.13	652	20	97%
Replacement	$ 1.84	$ 2.35	$ 1.83	20	0	102%

Average hourly RU bid volume was 708 MW in April, down significantly from the level of 819 MW in March. The composition of RU bids was similar in April to that of March, as shown in the following chart. Marginal RU bid prices continued to be in the range of $15 - $20/MWh in April. The slight increase in the RU price was due in part to the fact that fewer RU bids were available to the ISO to meet RU requirements. Specifically, 52.3 percent of total RU bids were awarded in April, compared to 47.1 percent in March. Average hourly volume of bids with prices below $15/MWh was 304 MW in March, compared to 275 MW in April.

The significant increase in the price of Regulation Down (RD) service was due to the fact that fewer RD bids were available to the market, and those that were available were priced above levels seen in recent months. The average hourly Regulation Down (RD) bid volume was 676 MW in April, significantly lower than the level of 744 MW seen in March. Bids below $15/MWh accounted for 36.2% of total RD bids in April, a decrease from 40.2% in March. In contrast, bids priced $15 to $30/MWh accounted for 42.3% of all RD bids, a significant increase from 32.7% in March.

A similar situation occurred in the spinning (SP) reserve market. The average hourly SP bid volume was 934 MW in April, compared to 1041 MW in March. Bids below $5/MWh accounted for 57.9% of total SP bids in April, a decrease from 68.9% in March. In contrast, bids priced above $5/MWh accounted for 42.1% of all SP bids, a significant increase from 31.1% in March

IV. Interzonal Congestion

Congestion costs reached $3 million in April, more than twice the level seen in March, due to various line de-rates. Of the $3.1 million in inter-zonal congestion costs, approximately $1.65 million was incurred due to congestion on Path 26 in the north-to-south direction. All other congestion costs occurred in the import direction. COI, Mead, NOB, and Palo Verde had import congestion costs of $693,000, $135,000, $260,000, and $264,000, respectively.

Congestion costs on Path 26 of $1.65 million occurred almost entirely during the first four days of the month, as that line remained partially derated following the Vincent substation fire on March 21. Since April 5, Path 26 has been rated at a north-to-south capacity of 2,500 MW, with congestion occurring in only a few peak hours in the later period of the month, and minimal congestion costs.

In addition, COI, NOB, and Palo Verde all experienced disparate levels of derates in April. COI reported a significant amount of hour-ahead congestion from April 7 to 17, and from April 24 to 26, due to scheduled maintenance. Also, NOB was partially derated during different periods in the month, causing significant congestion costs on April 8, 9, 14, 15, and 17. Finally, on HE 9 on April 28, there was a day-ahead congestion price spike of $67.79/MWh on Palo Verde in the import direction, due to scheduled maintenance work on the Devers-Palo Verde 500 kV line.

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	No. of Cngs. Hours	Pct of Hours Being Cng.	Avg Cng. Price
BLYTHE	Import	ON-PEAK				3	0%	110.95
COI	Import	OFF-PEAK	14	2%	3.36	12	2%	10.54
COI	Import	ON-PEAK	209	29%	3.19	74	10%	12.75
MEAD	Import	OFF-PEAK	1	0%	5.00	1	0%	21.13
MEAD	Import	ON-PEAK	19	3%	8.42			
NOB	Import	ON-PEAK	72	10%	3.42	36	5%	14.16
PALOVRDE	Import	OFF-PEAK				1	0%	10.00
PALOVRDE	Import	ON-PEAK	54	7%	4.21	43	6%	2.78
SUMMIT	Import	ON-PEAK	13	2%	8.32			
PATH26	Export	ON-PEAK	48	7%	29.42	10	1%	3.94
PATH26	Export	OFF-PEAK	1	0%	0.00			

Table 5. Interzonal Congestion Costs

Branch Group	Day-ahead Congestion Costs		Hour-ahead Congestion Costs		Congestion Costs		Total Congestion Costs
	Import	Export	Import	Export	Import	Export	
BLYTHE	$0	$0	$12,614	$0	$12,614	$0	$12,614
COI	$678,285	$0	$14,497	$0	$692,782	$0	$692,782
LUGOIPPDC	$94,875	$0	$2,472	$0	$97,347	$0	$97,347
LUGOWSTWG	$0	$0	$307	$0	$307	$0	$307
MEAD	$134,767	$0	$529	$0	$135,296	$0	$135,296
NOB	$255,183	$0	$5,179	$1	$260,362	$1	$260,364
PALOVRDE	$271,179	$0	$10,215	$0	$281,394	$0	$281,394
PATH26	$0	$1,651,593	$0	$1,048	$0	$1,652,640	$1,652,640
SILVERPK	$0	$0	$0	$0	$0	$0	$0
SUMMIT	$12,978	$0	$0	$0	$12,978	$0	$12,978
						Grand Total	$3,145,723

V. Firm Transmission Rights Market

FTR scheduling. FTRs released in January 2002, expired on March 31, 2003. Beginning April 1, 2003 a new FTR cycle began, using the FTRs released in the primary auction held in January 2003. 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 certain paths (89% on Eldorado, 70% on IID-SCE, 67% on Paloverde, and 98% on Silverpeak in the import direction). FTRs on those paths are owned primarily by Southern California Edison Company (SCE1).

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	261	725	500	35%
ELDORADO	IMPORT	510	455	510	510	89%
IID-SCE	IMPORT	600	340	390	390	57%
LUGOIPPDC**	IMPORT	358	321	353	225	90%
LUGOTMONA**	IMPORT	167	61	99	61	36%
LUGOWSTWG**	IMPORT	93	27	40	28	29%
MEAD	IMPORT	516	92	225	150	18%
NOB	IMPORT	686	158	434	197	23%
PALOVRDE	IMPORT	627	420	425	400	67%
SILVERPK	IMPORT	10	10	10	10	98%
VICTVL	IMPORT	991	15	50	50	2%
NOB	EXPORT	664	13	81	81	2%
PATH26	N->S	1,425	288	705	375	20%

*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 April. Due to significant congestion on Path 26, FTR revenue per MW in the north to south direction peaked at $1,147/MW. FTR revenues on several other paths were also significant, particularly on COI, NOB, and Palo Verde, on each of which FTR revenue exceeded $200/MW.

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

Branch Group	Direction	Apr	Cumm. Net REV	Pro-rate Annual FTR Rev*	FTR Auction Price
BLYTHE	IMPORT	69	69	824	5,460
COI	IMPORT	723	723	8,672	19,828
LUGOIPPDC**	IMPORT	272	272	3,262	N/A
LUGOWSTWG**	IMPORT	3	3	40	N/A
MEAD	IMPORT	166	166	1,990	7,820
NOB	IMPORT	249	249	2,991	12,245
PALOVRDE	IMPORT	233	233	2,800	88,167
SUMMIT	IMPORT	108	108	1,297	650
PATH26	EXPORT	1,147	1,147	13,770	8,602

*Pro-rated 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 LUGOIPPDC and LUGOWSTWG were awarded to municipal utilities that converted their lines to the ISO. They were not released in the primary auction.

FTR Concentration. There was a secondary FTR market trade on March 28, 2003, involving FTRs on three branch groups. Citadel Energy (CEPL) transferred its FTRs on Mead (35 MW in the import direction), Summit (23 MW in the import direction), and Victorville (100 MW in the import direction), to Constellation Power (CPSC), for the entire FTR effective period (from April 1, 2003, to March 31, 2004).

The following table shows FTR owner concentrations at or above 25% on different paths (Branch Groups and Direction) as of the end of April 2003. FTRs on paths that had a higher frequency of congestion are mostly held by investor-owned utilities. For instance, FTRs on Palo Verde (import) and Eldorado (import), COI (import), and Path26 (export) are mostly owned by Southern California Edison Company (SCE1), Pacific Electric & Gas Company (PCG2), and San Diego Gas & Electric's merchant division (SDG3). NOB was one exception that recently experienced some congestion, however, FTR concentration on NOB is relatively low, and the largest FTR owner, British Columbia Power Exchange (PWRX), owns approximately 29% of FTRs on this path.

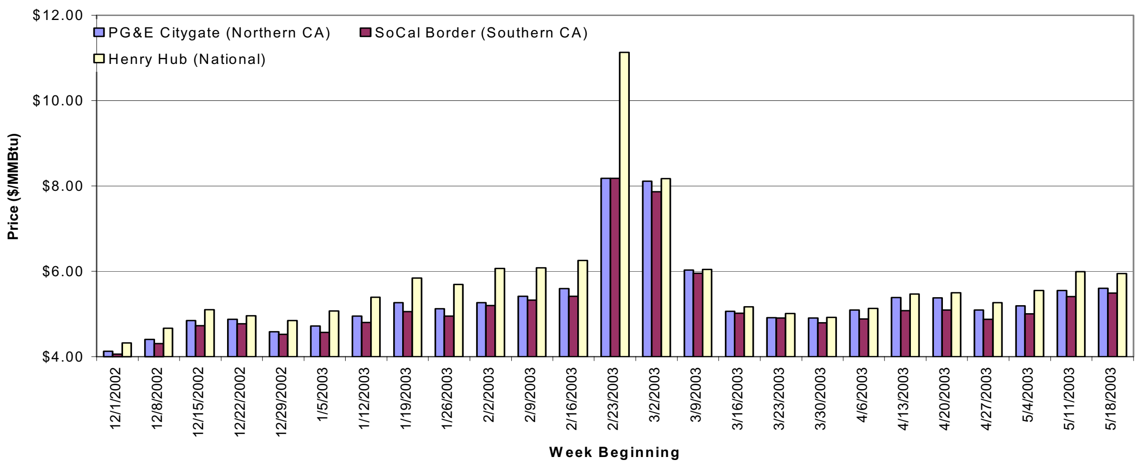
Table 8. FTR Concentration as of April 30, 2003

Direction	Branch Group	Owner ID	Owner Name	Hours Max FTR Owned	Total FTRs Auctioned	Max FTRs Owned	% Conc.
IMP	BLYTHE	FPPM	FPL Energy Power Marketing, Inc.	8089	167	167	100
	CFE	CRLP	Coral Power, LLC	8089	100	50	50
	CFE	WESC	Williams Energy Marketing and Trading	8089	100	25	25
	CFE	SETC	Sempra Energy Trading Corporation	8089	100	25	25
	COI	PCG2	Pacific Gas & Electric Company-PCG2	8089	745	500	67
	ELDORADO	SCE1	Southern California Edison Company	8089	510	410	80
	IID-SCE	SCE1	Southern California Edison Company	8089	600	460	77
	IID-SDGE	SCE1	Southern California Edison Company	8089	62	62	100
	LUGOGONDR	ANHM	City of Anaheim	8089	9	9	100
	LUGOIPPDC	ANHM	City of Anaheim	8089	358	230	64
	LUGOIPPDC	RVSD	City of Riverside	8089	358	128	36
	LUGOMKTPC	RVSD	City of Riverside	8089	247	106	43
	LUGOMKTPC	ANHM	City of Anaheim	8089	247	63	26
	LUGOTMONA	ANHM	City of Anaheim	8089	167	100	60
	LUGOTMONA	RVSD	City of Riverside	8089	167	67	40
	LUGOWSTWG	ANHM	City of Anaheim	8089	93	47	51
	LUGOWSTWG	VERN	City of Vernon	8089	93	28	30
	MEAD	MAEM	Mirant Inc. – MAEM	8089	516	150	29
	MEAD	TEMU	TransAlta Energy Marketing (U.S.) Inc	8089	516	136	26
	NOB	PWRX	British Columbia Power Exchange	8089	686	197	29
	PALOVRDE	SCE1	Southern California Edison Company	8089	627	602	96
	PATH26	SETC	Sempra Energy Trading Corporation	8089	285	100	35
	PATH26	MAEM	Mirant Inc. – MAEM	8089	285	75	26
	SILVERPK	SCE1	Southern California Edison Company	8089	10	10	100
	SUMMIT	SETC	Sempra Energy Trading Corporation	8089	98	25	26
	SUMMIT	PWRX	British Columbia Power Exchange	8089	98	25	26
	SUMMIT	MAEM	Mirant Inc. – MAEM	8089	98	25	26
	SYLMAR-AC	AZUA	City of Azusa	4417	50	35	70
	SYLMAR-AC	BAN1	City of Banning	8089	50	15	30
	VICTVL	WESC	Williams Energy Marketing and Trading	8089	991	299	30
	VICTVL	ANHM	City of Anaheim	8089	991	270	27
EXP	BLYTHE	MAEM	Mirant Inc. – MAEM	8089	72	25	35
	BLYTHE	SETC	Sempra Energy Trading Corporation	8089	72	25	35
	BLYTHE	WESC	Williams Energy Marketing and Trading	8089	72	22	31
	CFE	SETC	Sempra Energy Trading Corporation	8089	100	50	50
	CFE	WESC	Williams Energy Marketing and Trading	8089	100	50	50
	ELDORADO	SETC	Sempra Energy Trading Corporation	8089	536	200	37
	ELDORADO	WESC	Williams Energy Marketing and Trading	8089	536	186	35
	IID-SDGE	WESC	Williams Energy Marketing and Trading	8089	62	37	60
	IID-SDGE	NEI1	NewEnergy Inc.	8089	62	25	40
	LUGOMKTPC	RVSD	City of Riverside	8089	247	106	43
	LUGOMKTPC	ANHM	City of Anaheim	8089	247	63	26
	LUGOTMONA	ANHM	City of Anaheim	8089	543	350	64
	LUGOTMONA	RVSD	City of Riverside	8089	543	193	36
	LUGOWSTWG	ANHM	City of Anaheim	8089	93	47	51
	LUGOWSTWG	VERN	City of Vernon	8089	93	28	30
	MEAD	MAEM	Mirant Inc. - MAEM	8089	464	141	30
	PALOVRDE	SETC	Sempra Energy Trading Corporation	8089	870	250	29
	PALOVRDE	WESC	Williams Energy Marketing and Trading	8089	870	245	28
	PATH15	AZUA	City of Azusa	4417	20	15	75
	PATH15	BAN1	City of Banning	4417	20	5	25
	PATH26	SCE1	Southern California Edison Company	8089	1425	575	40
	PATH26	SDG3	San Diego Gas & Electric, Merchant	8089	1425	560	39
	SILVERPK	WESC	Williams Energy Marketing and Trading	8089	10	10	100
	SYLMAR-AC	AZUA	City of Azusa	4417	45	25	56
	SYLMAR-AC	BAN1	City of Banning	8089	45	15	33

VI. Regional Natural Gas Markets

Natural gas prices were relatively flat in April compared to prices in March, and stayed within the $4.50-to-$5.50/MMBtu range throughout April. Prices were highest in the third week of April due to reports of gas withdrawals from storage amid cold weather in the Northeast. Malin prices were $0.50/MMBtu lower than PG&E Citygate prices for much of the month, due to available hydroelectric power, abating the demand for gas-fired generation. Natural gas prices ended April at below $5.00/MMBtu. The following chart shows daily regional natural gas delivery prices for April.

Figure 9. Weekly Average Regional Natural Gas Prices in April

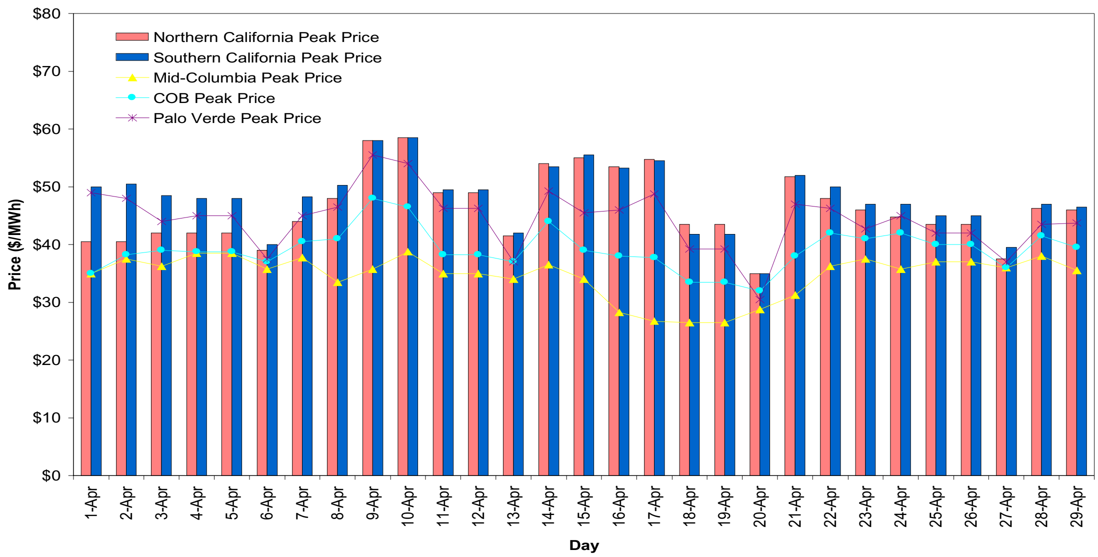


VII. Regional Bilateral Electricity Markets

Ongoing Path 26 problems relating to the Vincent substation explosion generated spreads ranging from $5 to $10/MWh between Northern and Southern California prices for the first week of April, with other regional hubs matching the California prices. After the first week, regional day-ahead electricity prices remained substantially in the $50-55/MWh range for California, between $40 and $55/MWh at Palo Verde, between $35 and $50/MWh at the California-Oregon Border (COB), and between $25 and $40/MWh at Mid-Columbia. A planned outage from April 7 to April 10 causing a derate of COI to 2900 MW from North to South resulted in the highest California prices of the month at $58/MWh.

The third week of April saw slightly higher California natural gas prices, resulting in higher California prices. Mid-Columbia prices fell below $30/MWh on reduced load due to the Easter weekend and moderate temperatures. Hydroelectric output from the Northwest was reduced in the fourth week of April, resulting in convergence between California and Northwest electric prices. April electricity prices ended in the $38 to $50/MWh range, with small price spreads between the Northwest, Southwest, and California. The following chart shows daily bilateral contract prices for electricity delivered in California and at regional trading hubs in April.

Figure 10. Regional Day-Ahead Bilateral Peak Electricity Prices in April[4]

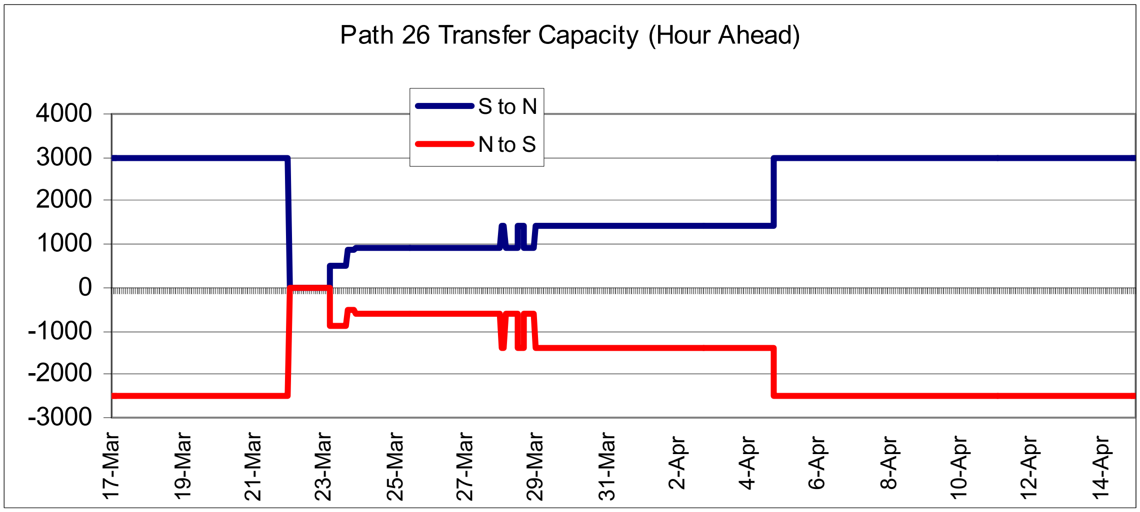


VIII. Issues under Review

Vincent Substation. On March 21 at about 6:30 p.m., the B phase of Southern California Edison's Vincent #2 AA 500/220 kV transformer bank suffered a catastrophic failure and started an oil fire at the substation. This resulted in the loss of five 500 kV lines, three 500/220 kV transformer banks and eight 220 kV lines. Starting the evening of March 22, service began to be restored to the substation. By the evening of March 23, the Path 26 N-S limit was 600 MW and the S-N limit was 925. Between March 24 and 27, several lines returned to service, as did the #3 AA 500/220 kV transformer bank, increasing the transfer capability to 1400 MW in both directions. On April 4, the #1 AA 500/220 kV transformer bank returned to service, restoring the Path 26 N-S transfer capability to 2500 MW and the S-N limit to 3000 MW, the level of its capability prior to the fire.

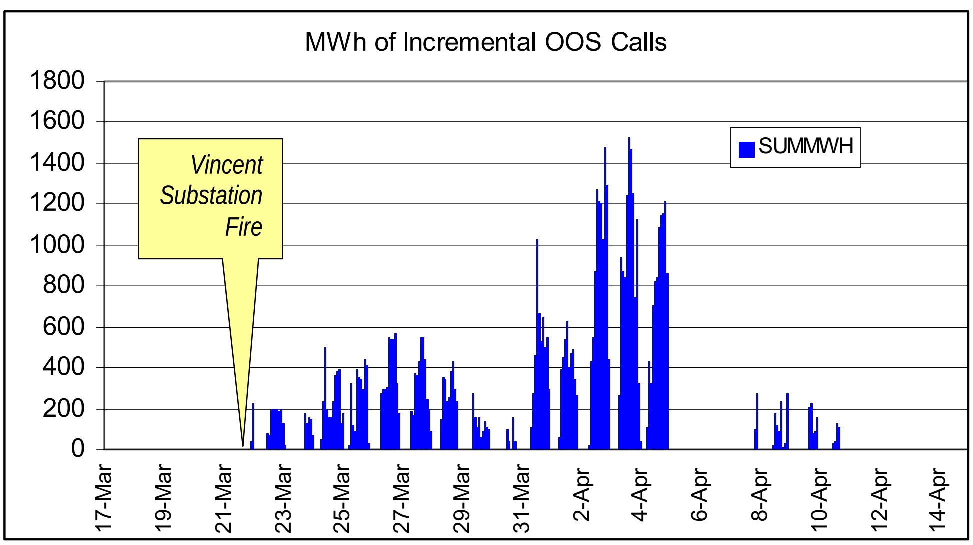
[4] Regional Prices obtained from *Energy Market Report*.

Figure 11. Path 26 Transfer Capability, March 17 through April 15



A third transformer bank (the replacement for the one that exploded) is expected to be in operation by the end of August 2003. This should return the N-S transfer capability to 3000 MW. As noted above, units in Southern California load pockets were called out of sequence to manage intrazonal congestion between March 21 and April 4, as a substitute for power that otherwise would have been delivered over Path 26 or through the overloaded Sylmar substation. Out-Of-Sequence (OOS) calls to generators in the SP15 area are shown in Figure 12 below.

Figure 12. System-wide Gross Volume of Incremental OOS Calls



From a market analysis perspective, an event of this nature has the potential to confer temporary Locational Market Power on certain participants with advantageous positions on the grid, outage status, load conditions etc. Given the sudden and catastrophic nature of this event, and the operational changes made to deal with it, a brief investigation was undertaken to examine the behavior of market participants during this period of increased vulnerability. Had generators believed that they had a high probability of being called incrementally OOS they could have potentially exercised market power either by increasing their bid prices, and/or decreasing their forward schedules. Changing one's behavior in response to system conditions has been identified by FERC as non-competitive behavior and is subject to sanction.

In the four week period from March 18 to April 18, 88,000 MWh of energy was called out of sequence, at a gross cost of $6 million, and almost all of it attributable, in one way or another, to the Vincent substation fire. The re-dispatch premium (i.e., uplift over the Market Clearing Price) was approximately $3 million, and of this there was Potential Market Power of $1.4 million derived from statically high bids that were called on due to the outage[5].

The bidding and scheduling behavior of all units that were called OOS was examined in some detail for the period stretching from February 18 of to April 18. The examination period was stretched at either end to provide bidding and scheduling context. There was evidently neither a significant increase in bid prices, nor a concomitant decrease in forward scheduling during and following the Vincent substation outage.

HE 23:00 Price Spikes. As noted in recent months in these Reports, the ISO has observed price spikes consistently in HE 23:00. The ISO is currently in the process of investigating this phenomenon to determine its causes and potential solutions.

[5] See 2002 Annual Report on Market Issues and Performance, Section 8.2 footnote 2 for the methodology and appropriate definition. Available at http://www.caiso.com/docs/2000/07/27/2000072710233117407.html