CALIFORNIA ISO

Memorandum

To: **ISO Board of Governors**

From: **Greg Cook, Manager of Market Monitoring**

cc: **ISO Officers, ISO Board Assistants**

Date: **May 21, 2004**

Re: **Market Analysis Report for April 2004**

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

Executive Summary

The unusually warm spring continued with the highest April peak load on record by a considerable margin at 39,040 MW, a level typically not seen until late May or June, during the afternoon of April 27. Temperatures typical of midsummer pushed loads well above forecasts, beginning April 12, and cresting during the heat wave of April 26-28, when the peak temperature reached 103 degrees in the Ontario area. Consequently, the Sierra Nevada snowpack has continued to decrease at a faster rate than normal, and the snow-water equivalent had deteriorated to less than 50 percent of average by May 6. This increases the risk of an adverse resource adequacy condition, should the trend of high temperatures continue into the summer, particularly in transmission-constrained areas within Southern California. Load-serving entities were underscheduled by 2.8 percent on average in April, about double the level seen in March. Real-time incremental and decremental balancing energy prices respectively averaged $72.61 and $24.29 per megawatt-hour (MWh), similar to levels seen in recent months.

Intrazonal (within zone) congestion redispatch costs were down significantly in April to $5.7 million from $8.1 million in March. The decrease was largely due to a decline in congestion in the San Diego region as a result of the return of the San Onofre Nuclear Generating Station (SONGS) Unit 2 in early April.

Average ancillary service (A/S) prices decreased 13.4 percent in April from March levels due to decreased prices in the regulation markets. Several resources that had previously participated in A/S markets only occasionally bid into the markets more regularly in April, leading to increased supply, and a 41 percent reduction in the frequency of bid insufficiency compared to March. However, many of these bids were at high prices, resulting in average price increases for spinning reserves, non-spinning reserves, and upward regulation, to the range of $70 to $90 per megawatt (MW), on several occasions throughout April. The total market impact of these price spikes is estimated at $1 million.

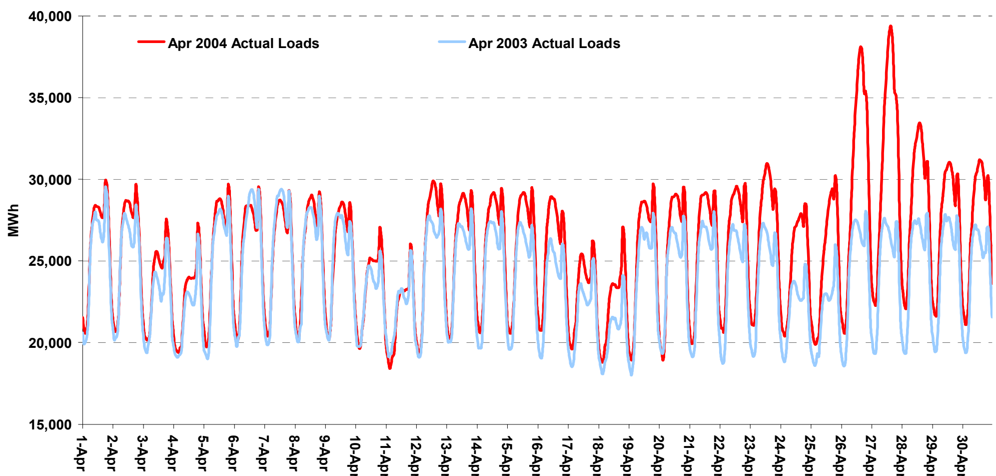
Interzonal congestion costs totaled $1.6 million in April, down significantly from the March level of $4.5 million. As in previous months, the bulk of the congestion costs was incurred on Path 26 and Palo Verde, in efforts to import power into Southern California to meet unseasonably high loads.

I. Fundamental Conditions Affecting Demand and Supply

- ***Peak load grew 31.1 percent in April 2004 v. April 2003, due to April 26-28 heat wave***
- ***Hydroelectric conditions continue to deteriorate***

Beginning April 12, 2004, and continuing into May, loads outpaced those in April 2003 by an overwhelming margin. Due to both load growth and persistent heat across California, loads increased by 7.1 percent on average to 25,730 MW in April, compared to 24,029 MW in April 2003. More significantly, an extraordinary heat wave that occurred April 26-28 caused the April peak load to rise to 39,400 MW, a 31.1 percent increase from the April 2003 peak load of 30,062 MW. The ISO has consistently seen loads approximately 4 percent above those for the same month in the previous year, between July 2003 and April 2004. This is the case not only during peak hours, but during off-peak hours as well, indicating some load growth beyond the influence of weather. The following chart shows hourly loads in April 2003 and 2004.

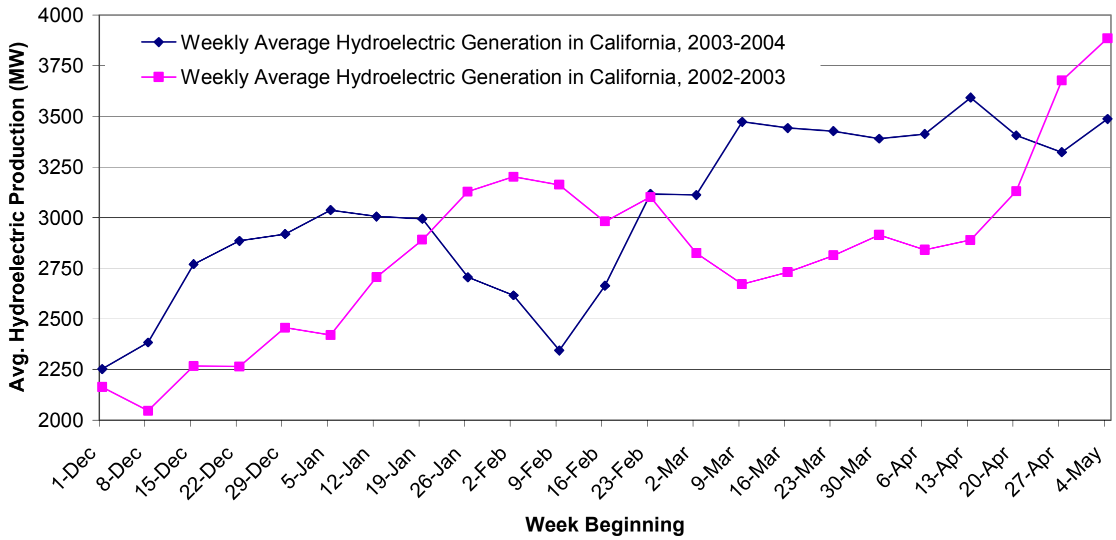
Figure 1. Hourly Actual Loads, April 2004 v. 2003



Hydro Conditions. The continued unseasonably warm weather has further eroded snowpacks in California and the Pacific Northwest. The snow-water equivalent in the California Sierra Nevada stood below 50 percent of average by the first week in May, compared to 70-80 percent of average four weeks earlier, and well above 100 percent of average in early February.[1] This year, hydroelectric production has been relatively constant since early March, averaging in the neighborhood of 3,500 MW. In April 2003, the runoff season was just beginning, and hydroelectric production increased sharply between April and May. The following chart shows approximate weekly average hydroelectric production within the ISO Control Area through early May for the 2003-04 and 2002-03 seasons.

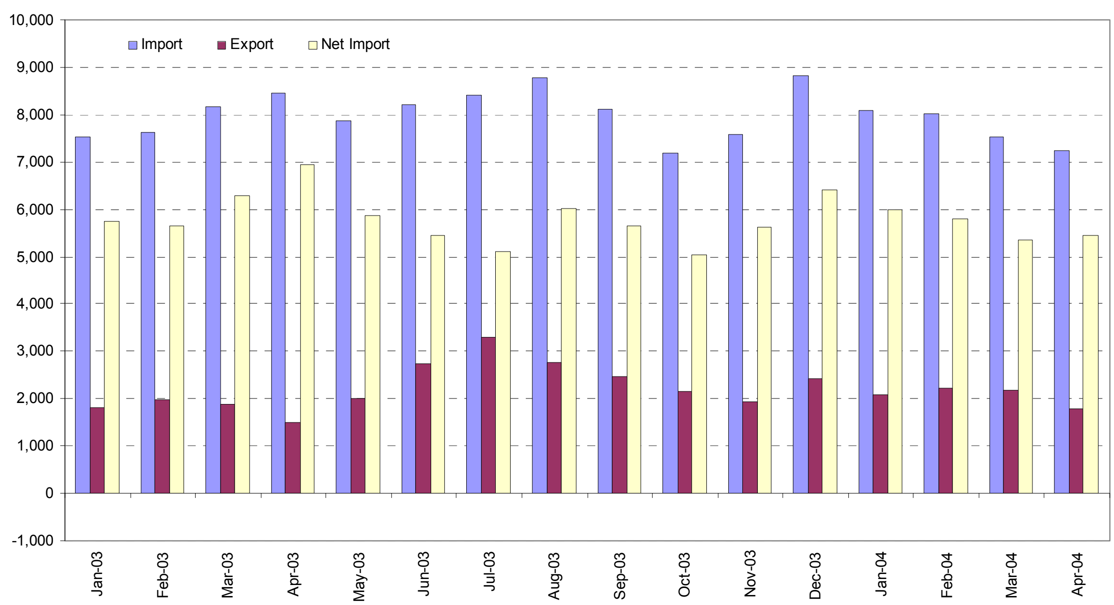
[1] Source: USDA Natural Resources Conservation Service, http://www.wcc.nrcs.usda.gov/water/drought/wdr.pl.

Figure 2. Approximate Weekly Average Hydroelectric Production



Imports and Exports. Other areas in the western United States have also experienced an unseasonably warm spring, causing high loads and early runoff in those locations as well. As a result, net scheduled imports have decreased to an average of 5,443 MW in April 2004, compared to 6,949 MW in April 2003. This is due largely to fewer imports from the Pacific Northwest. The following chart shows monthly average import, export, and net import schedules through April 2004.

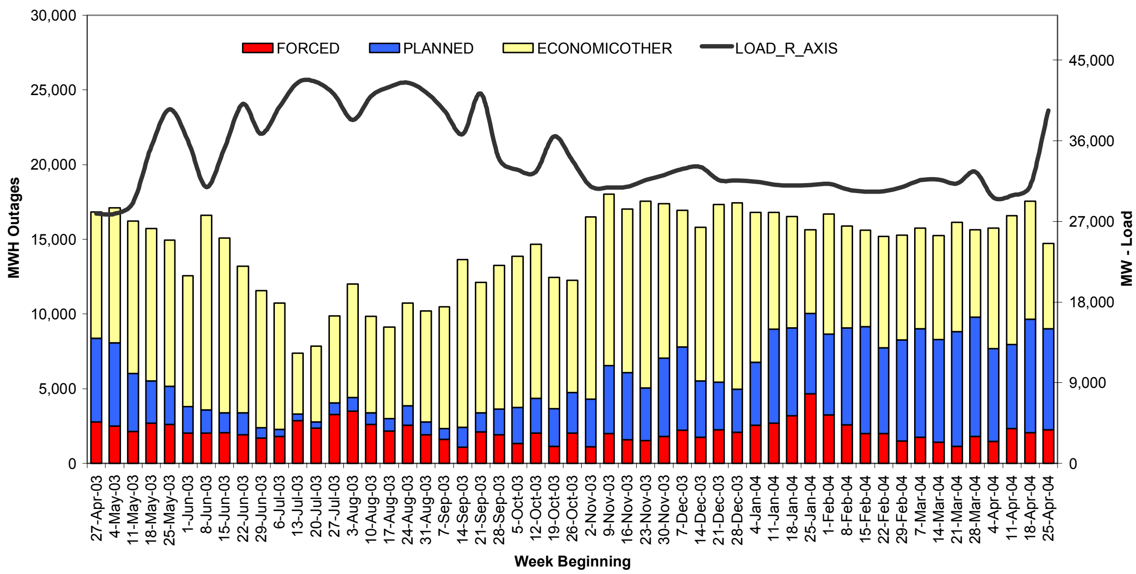
Figure 3. Monthly Average Scheduled Imports and Exports through April



Outages. Planned outages remained high during the typical spring maintenance season. The San Onofre Nuclear Generating Station (SONGS) Unit 2 returned to service in early April from a planned refueling, but also incurred a brief forced outage on April 10. The 1,100 MW Diablo Canyon Unit 1 began a planned refueling/maintenance outage on March 22 and is not expected to return to service until May 28.

On April 27, the day of the load spike, approximately 5,000 MW of generation that had been off-line under approved waivers to the Must-Offer Obligation returned to service, as the ISO called upon those units to meet the high load. By 3:00 p.m., the beginning of the peak hour, fewer than 200 MW remained off-line under waiver within SP15. Meanwhile, over 1,500 MW were off-line due to forced outages at that hour. The following chart shows weekly average outages by type through April 2004.

Figure 4. Weekly Average Outages and Daily Peak Load through April 2004



Bilateral Electricity and Natural Gas Prices. Prices for day-ahead electricity delivered under bilateral contracts were relatively flat in April at approximately $46 and $51/MWh for NP15 and SP15 respectively, reflecting South-to-North congestion and frequent path mitigation pursuant to the Southern California Import Transmission nomogram (SCIT), a technical limit on the total import volume of energy into Southern California at any given moment. In anticipation of high loads, day-ahead prices spiked on April 27 beyond $60/MWh. Natural gas prices nearly approached $6 per million British thermal units (MMBtu) until April 12, at which point they retreated to the mid-$5/MMBtu range. Gas prices spiked again to the high $5/MMBtu range on April 27, driven by electricity demand. For more information, please see the sections below on bilateral electricity and natural gas prices.

II. Real-Time Balancing Energy Market

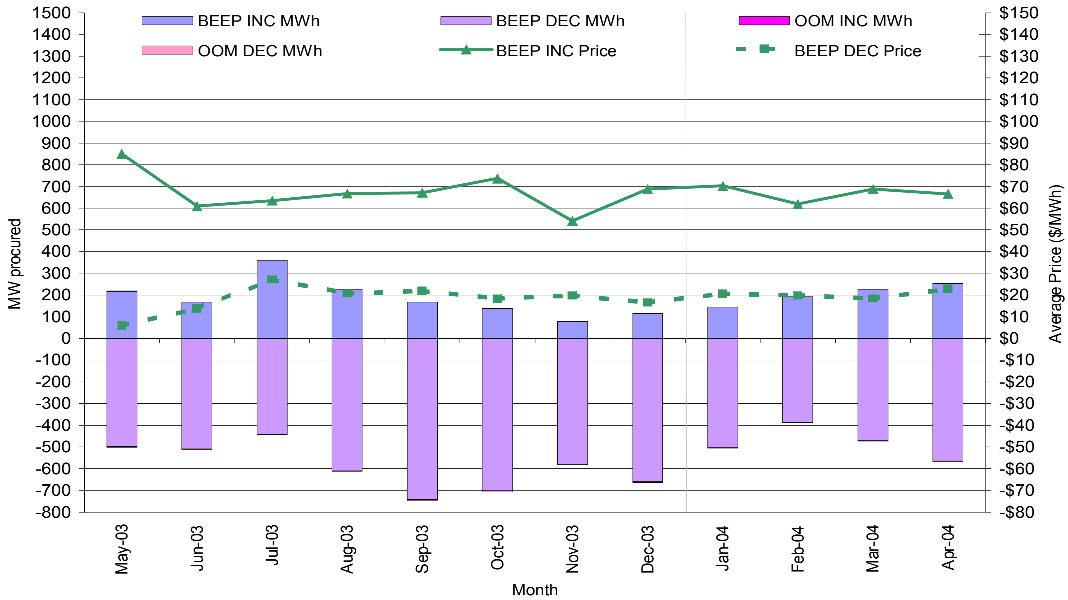
- ***Near-zero DEC prices a result of additional seasonal hydroelectric production during off-peak hours***
- ***Late April heat wave created a significant imbalance; INC prices were high for a relatively brief period***
- ***Intrazonal (within zone) Congestion Redispatch Premium Costs Totaled $5.7 million***

Real-time energy imbalances have increased to levels seen more typically during summer, in step with temperatures and loads that also are following a summer pattern. Average real-time incremental (INC) volume, the amount of energy by which the ISO instructs generators to increase output when scheduled energy is not sufficient to meet load, increased to 252 MW on average in April, compared to 212 MW in March. Decremental (DEC) volume, the amount of energy by which the ISO instructs generators to decrease output whenever schedules are in excess of actual load, averaged 566 MW in April, compared to 479 MW in March. Real-time prices were consistent with those seen in nearly all of the last 12 months, averaging $66.64 and $22.77/MWh for INC and DEC energy in April, respectively, compared to $69.03 and $18.06/MWh in March. Other variables equal, higher INC prices and lower DEC prices result in overall higher costs to load. The table below shows total dispatched energy and average prices in April, as well as average loads and underscheduling. The chart immediately following shows monthly average prices and volumes for the twelve months through April.

Table 1. Total Energy and Average Prices, Loads, and Underscheduling in April

	Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	**Dec**	
Peak	$ 72.61	$ 24.30	27,779 MW
	118,509 MWh	344,358 MWh	2.4%
Off-Peak	$ 55.43	$ 14.50	21,615 MW
	63,014 MWh	63,520 MWh	3.8%
All Hours	$ 66.64	$ 22.77	25,730 MW
	181,524 MWh	407,878 MWh	2.8%

Figure 5. Monthly Average Real-Time Prices and Volumes through April

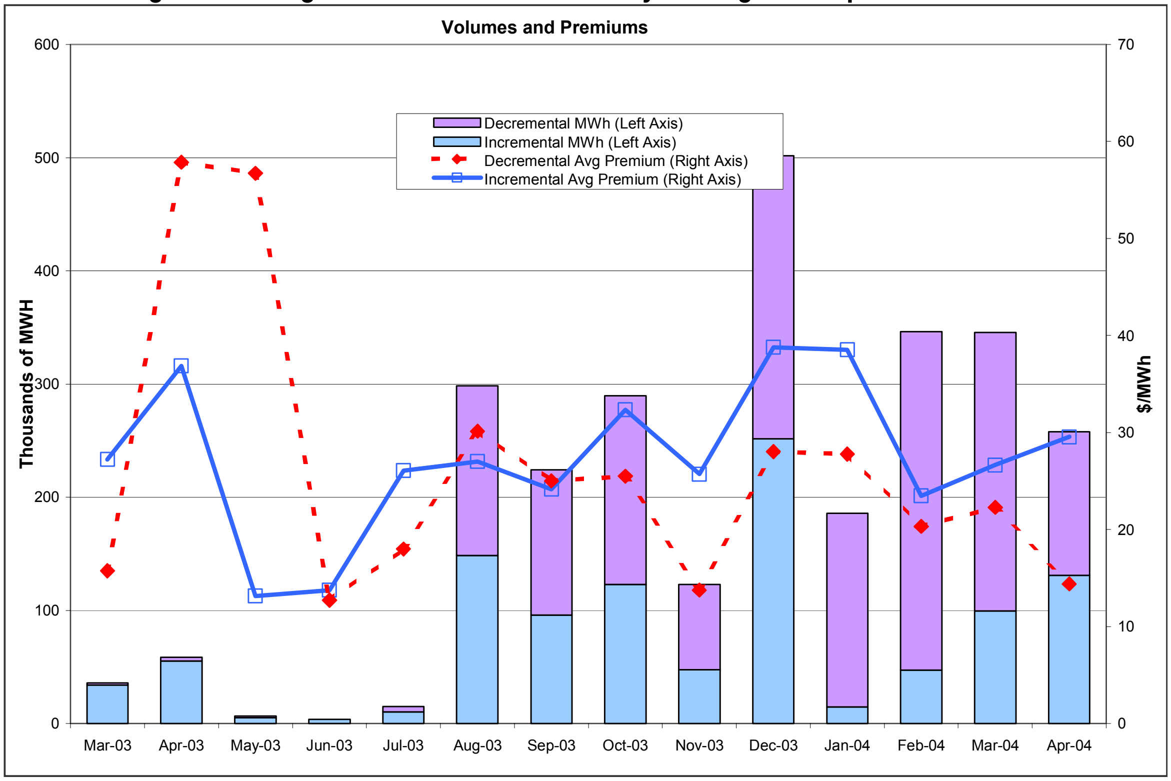


Real-Time Intrazonal Congestion Management. Intrazonal congestion costs decreased to $5.7 million in April, compared to $8.1 million in March. Decremental intrazonal congestion decreased significantly as a result of the return of the San Onofre Nuclear Generation Station (SONGS) Unit 2, helping to relieve congestion in the San Diego region, and decreasing the need for out-of-sequence (OOS) procurement. Incremental OOS calls were needed to manage congestion within SP15, due to constraints pursuant to the South-of-Lugo and SCIT nomograms, and to congestion on Path 26.

April congestion dispatches resulted in a total net cost (redispatch premium) of approximately $5.7 million. Total incremental and decremental congestion dispatch volume was 256 gigawatt-hours (GWh), and the average redispatch premium was $22.10/MWh. The following chart shows intrazonal congestion prices and volumes through April.[2]

[2] Congestion net cost or redispatch premium is calculated as total redispatch cost minus unconstrained dispatch cost, which is the equivalent dispatch cost at zonal MCP. The premium reflects the increased cost of redispatch and any potential mark-up above marginal cost.

Figure 6. Congestion Volume and Monthly Average Redispatch Premium



Incremental Congestion Dispatches. A total of 131 GWh of incremental energy was dispatched to address intrazonal congestion in February. The average price paid was $61.37/MWh, and the re-dispatch premium in excess of the Market Clearing Price (MCP) was approximately $3.8 million total, or $29.54/MWh. In substantially all cases, the congestion was caused by constraints on the transport of energy from generation to load in the Los Angeles area.

The situations of congestion are as follows:

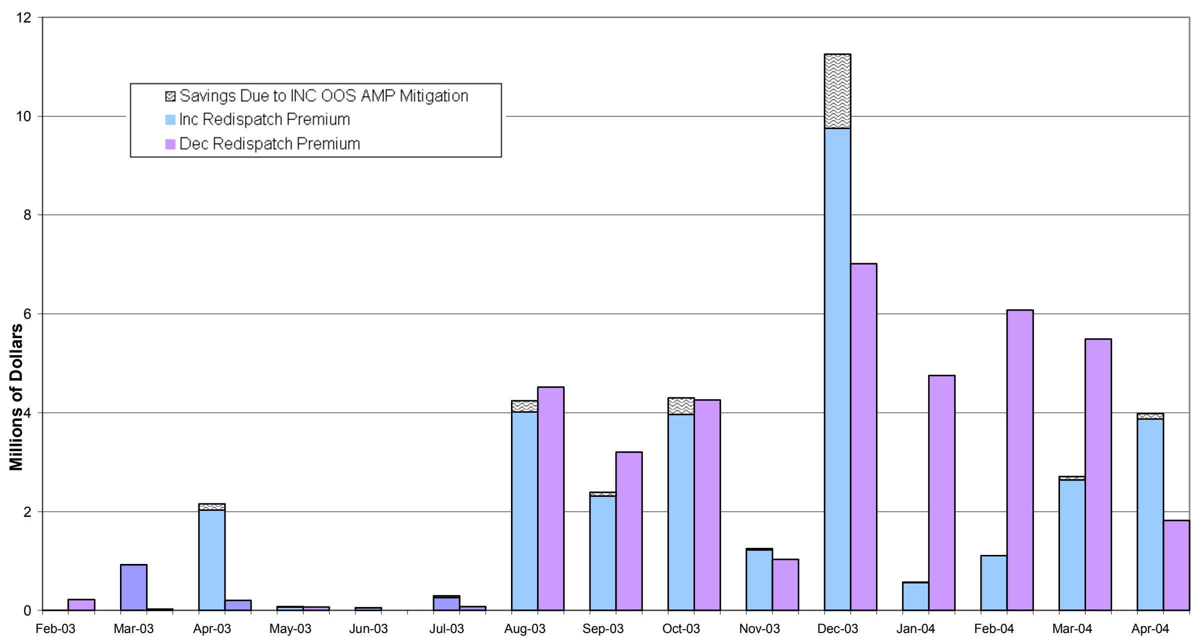
- **South-of-Lugo:** Due to congestion at the Lugo substation, north of San Bernardino, OOS incremental dispatches were made to units in the Los Angeles area, while units north of Lugo, such as High Desert, were decremented.
- **Path 26:** Real-time congestion has increased as a source of congestion
- **SCIT:** As noted above, SCIT is a limit on the amount of energy that can be simultaneously imported into Southern California.
- **Sylmar:** There were incidental OOS calls due to transmission line and substation maintenance, and at the Sylmar substation in particular.

Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of $114,861, or 3% of total the total redispatch premium costs in April. All incremental OOS dispatches are subject to mitigation.

Decremental OOS Dispatches. On the decremental side, a total of 126 GWh was dispatched out of sequence in April, down significantly from the March level of 246 GWh. This energy is settled according to the provisions of the Amendment 50 mitigation measures, as directed by FERC. The approximate re-dispatch premium in excess of the Market Clearing Price was $1.8 million, in April, or $14.40/MWh, compared to $5.5 million in March, or $23.72/MWh. As in previous months, almost all decremental OOS activity was due to intrazonal congestion in the San Diego region, caused by the combination of energy from the new generation units located in northern Mexico and energy imported on the SWPL (South West Power Link). However, the congestion in this area diminished considerably since February and March levels, due in part to the return of SONGS Unit 2 in early April.

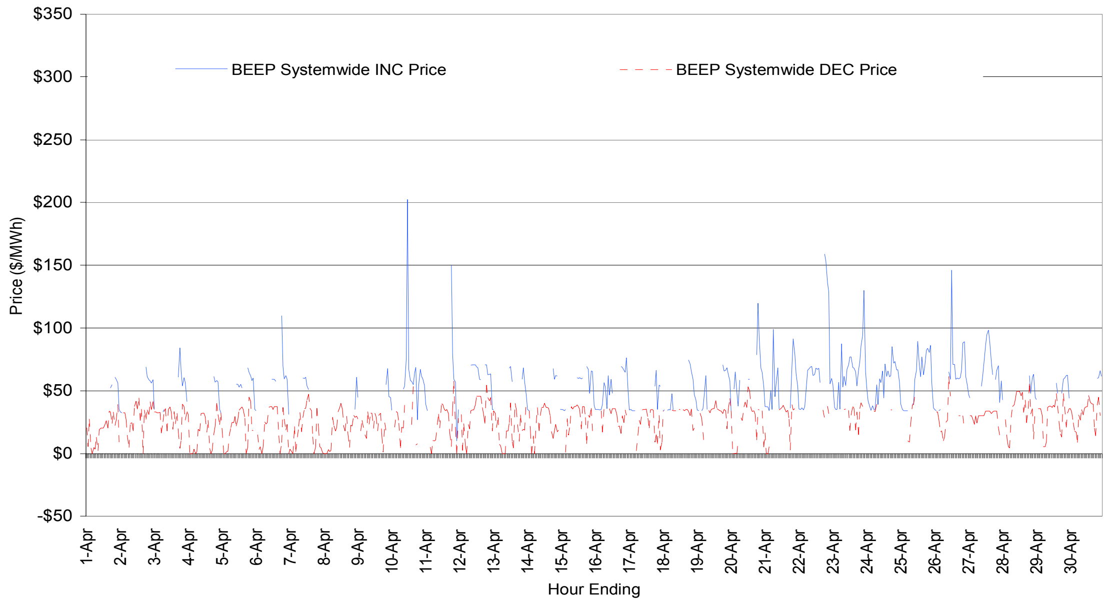
The following chart shows total redispatch premium costs for both decremental and incremental congestion, and savings due to mitigation of incremental OOS dispatches. As shown in the chart, minimal bid mitigation has occurred.

Figure 7. Re-dispatch Premiums and INC OOS Mitigation Savings



Price Spikes. Price spikes were relatively infrequent in April, when compared to those in the spring of 2003, and to other recent periods. While the spikes corresponding to reserve deficiencies and transmission line overloads during heat waves in March and April were significant and may be indicative of potential problems in the near future, they were for the most part anticipated, and utilities procured most of the energy they required to serve load in the forward markets. Given the unseasonably high load in April, these spikes were not as extraordinary or costly as the most extreme spikes of 2003 – notably those on May 29, July 2, August 12, and October 22, 2003 – or the spike of March 29, 2004. The following chart shows systemwide hourly average INC and DEC prices, followed by a brief description of the significant price spikes that occurred during April.

Figure 8. Systemwide Hourly Average Real-TIme Prices in April



Between March 16 and April 21, the decremental balancing energy price was often set by hydroelectric resources at approximately $0/MWh, as discussed in the previous Market Analysis Report. This price had been bid to signal a spilling condition, a situation in which water cannot be stored and is diverted from hydro turbines to spillways. Unlike gas-fired resources that save fuel costs when they are decremented, hydroelectric resources receive little or no benefit when they are decremented to the point of spilling. By late April, hydroelectric output was fully utilized to meet high loads. Consequently, decremental energy bids from hydroelectric resources near $0/MWh ceased on April 21.

On April 10, between 11:50 a.m. and 1:00 p.m., the systemwide INC price ranged between $120 and $222.79/MWh as a consequence of an unplanned outage the San Onofre Nuclear Generation Station Unit 2 in the San Diego Area. The peak dispatch of 2,860 MW occurred between 12:10 and 12:20 p.m., and included contingency reserves. In addition, the ISO secured energy out of market to resolve the contingency. Due to the short duration of the spike, automatic mitigation procedures (AMP) were not applied, as the forecasted imbalance energy price was below the AMP price screen threshold of $91.87/MWh.

On April 11, the SP15 INC price reached $150/MWh, set by an inefficient high-cost combustion turbine unit. At this time, ISO operators dispatched all available energy (1,322 MW) from the BEEP Stack within SP15 between 7:50 and 8:00 p.m.

On April 20, a large generator tripped offline resulting in a systemwide INC price of $181.96/MWh between 8:00 and 8:20 p.m. The price was set by the highest-priced bid in the bid stack, as ISO operators skipped several units for operational reasons.

On April 22, the systemwide INC price was set between $125.87 and $160/MWh, intermittently for a total of 100 minutes between 7:40 and 10:20 p.m., as a result of a significant real-time imbalance between load and scheduled generation. During this period, underscheduling reached as much as 6 percent of actual load.

In the last week of April, several spikes occurred due to the slow response of generators during periods of rapidly increasing load. On April 23, during five intervals between 10:10 and 11:30 p.m., the INC price reached $160/MWh. The maximum imbalance load reached 1,770 MW between 11:20 and 11:30 p.m.

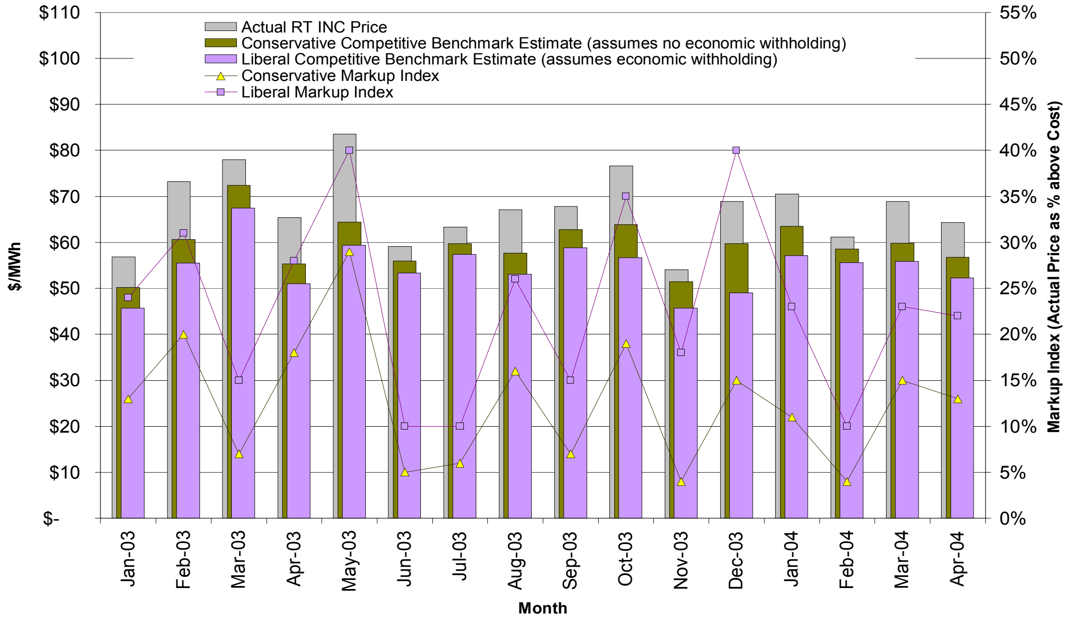
This occurred again on April 26, between 1:00 and 2:00 p.m., during which the SP15 INC price was set at $146.91/MWh. While the load spike was unusually large compared to the previous day, peaking at 38,007 MW between 3:00 and 4:00 p.m., it was only 215 MW (0.5 percent) above the day-ahead forecasted peak, estimated to occur in the same hour.

Finally, on April 27, the day on which Southern California temperatures exceeded 100 degrees, the SP15 INC price reached $104.25/MWh. The average dispatched volume was 1,431 MW, or 3.6 percent of the peak load of 39,040 MW.

Market Competitiveness. The real-time price-to-cost markup is an indicator of the competitiveness of the real-time market. The Department of Market Analysis calculates this index as a comparison of the actual incremental market-clearing price to a competitive benchmark price. As discussed in the Market Analysis Report dated February 19, 2004, the Department of Market Analysis now reports two indices of markup to present a range of the competitiveness of the real-time market. One index assumes no economic withholding; that is, it assumes that high-priced bids in the market reflect high costs. This produces a higher estimate of the competitive price and results in a conservative (lower) estimate of potential markup. The other index accounts for economic withholding by substituting estimated marginal cost-based bids for high-priced bids. This produces a lower estimate of the competitive price and a more liberal (higher) estimate of potential markup.

The price-to-cost markup in incremental balancing energy was down slightly in April to the range of 13 to 22 percent for the two indices, compared to the range of 14 and 22 percent in March. As in March, the ten highest markup hours accounted for nearly 25 percent of the monthly total markup. These hours were distributed across the month. Most of the price spikes were included during these periods but were relatively short-lived. Thus, unlike in recent months, spike hours did not cause an overwhelming proportion of the markup in April. The following chart compares monthly average prices to the two competitive benchmarks, and shows the two markup indices, through April.

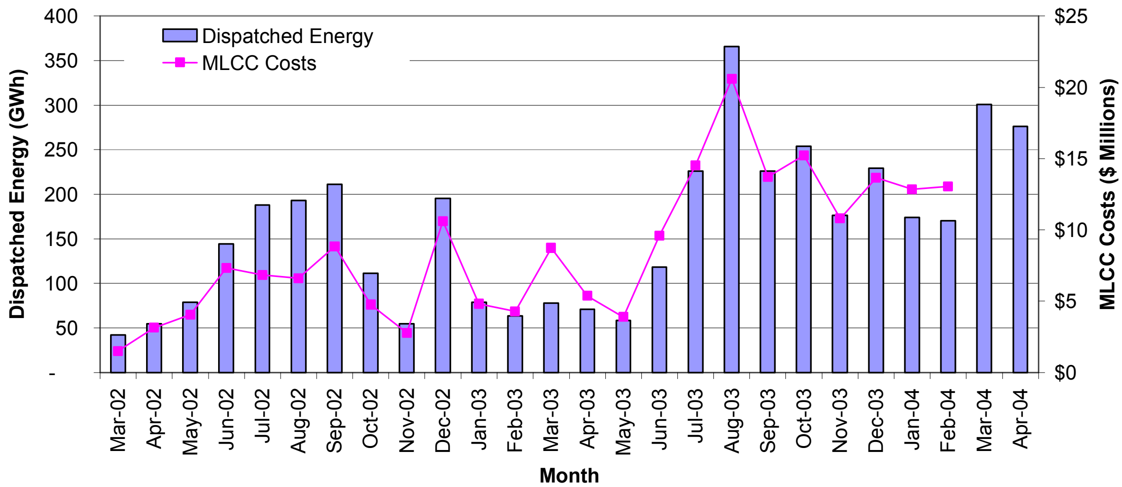
Figure 9. Range of Price-to-Cost Markup in Real-Time Incremental Energy through April



Minimum Load Cost Compensation. The Federal Energy Regulatory Commission directed in its June 19, 2001 Order, and upheld in later Orders, that all participating generation in the ISO Control Area must offer all available capacity into an ISO market (the "Must-Offer Obligation"). The Commission then approved a process by which units may apply to the ISO for waivers from the Must-Offer Obligation when not needed for reliability. In the event such a waiver is denied, the ISO will compensate the denied units their minimum-load operating costs, based upon a current gas price index.

In April, the output of units held at minimum load by denial of applications for waivers of the Must-Offer Obligation decreased slightly to 276 GWh in April, from 301 GWh in March.

Figure 10. Minimum Load Cost Compensation



III. Ancillary Services Market Conditions

- ***Prices decreased 13.4% on average for all services while overall demand decreased by 0.6% from March to April 2004.***
- ***Frequency of bid insufficiency decreased by 41% from March to April 2004, due to the increase in self-commitment of A/S resources.***

Market Prices. Market prices decreased in the ancillary services markets from March to April 2004. Overall demand decreased 0.6% in April, while overall supply increased by 1.1%. The majority of the decrease in average prices was caused by decrease in the regulation up (RU) and regulation down (RD) markets. The increase in non-spinning reserve (NS) prices offset the overall decline.

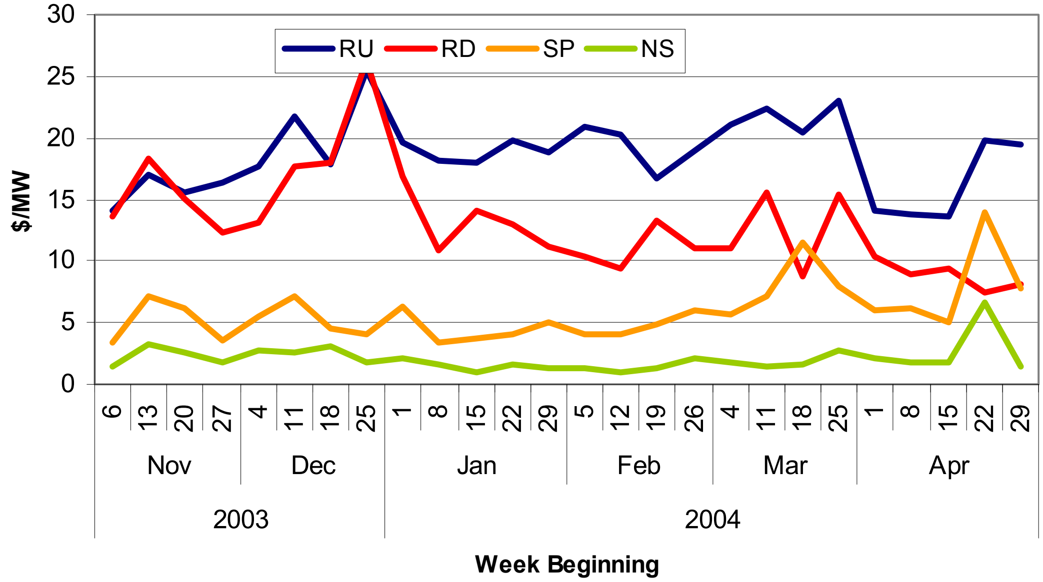
Table 2. Average Ancillary Service Requirements and Prices

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Mar 04	366	409	722	705	$ 21.53	$ 12.44	$ 7.81	$ 1.87
Apr 04	363	405	722	699	$ 15.68	$ 9.05	$ 7.89	$ 3.00

Several pricing events during the end of April also offset the overall decline. During March, there were several pricing events in the spinning reserve (SP) markets. During April, the pricing events were in the RU, SP and NS markets. On April 24, SP prices reached $82/MW in the day-ahead market for hours 13-14. On April 26, day-ahead RU prices held at $45.24/MW for hours 11-16, day-ahead SP maintained $70.06/MW for hours 13-21 and day-ahead NS was priced at $40/MW for hours 14-18. On April 27, day-ahead RU prices reached $70.07/MW in hours 9,12, day-ahead SP prices ranged from $70.06/MW to $90/MW in hours 13-17 and day-ahead NS prices met or exceeded $84/MW for four hours (13-15,17) peaking at $90/MW. The total market impact of these price spikes, or the cost of procuring these services at the monthly average price, is estimated at $1 million. A variety of resources that had participated infrequently in the A/S markets were prevalent in April, bringing additional capacity into the markets, at higher prices. These units set most of the prices above $45/MW.

The impact of these pricing events is evident when looking at weekly average prices in the ancillary services markets. The week beginning April 22 saw the highest weekly prices in the month of April in RU, SP and NS. The following chart shows weekly average prices by service type through April.

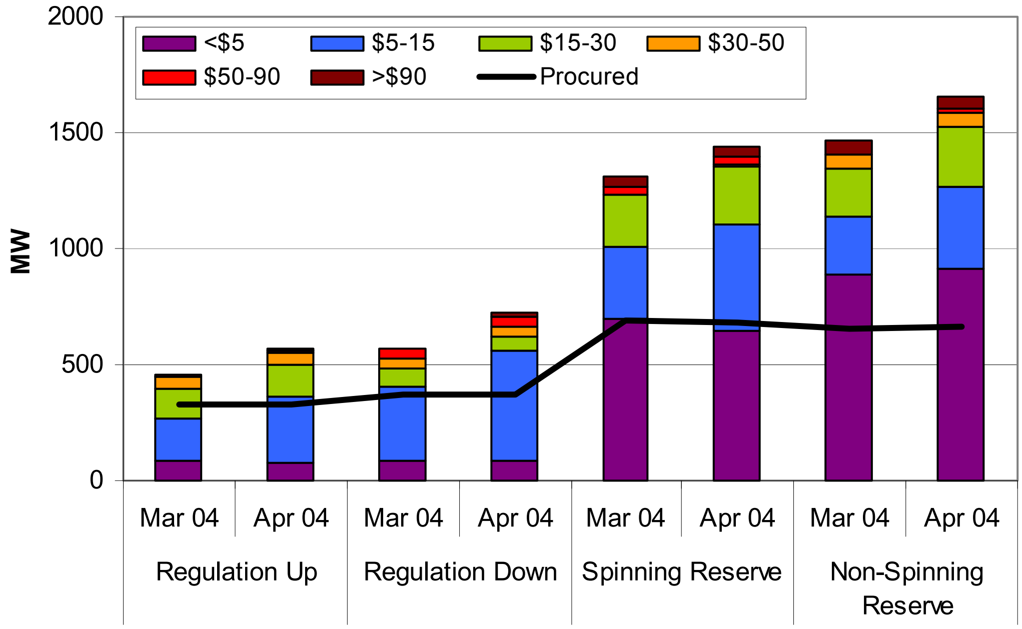
Figure 11. Weekly Weighted Average A/S Prices through Apr-04



Ancillary Service Market Supply. Market supply was characterized by a decrease in the frequency of bid insufficiency. Supply during peak periods increased with the demand for energy during unseasonably warm weather. The high load prompted several A/S certified resources to self-commit to sell energy. When the number of resources providing energy increased, the reserves available on peak also increased.

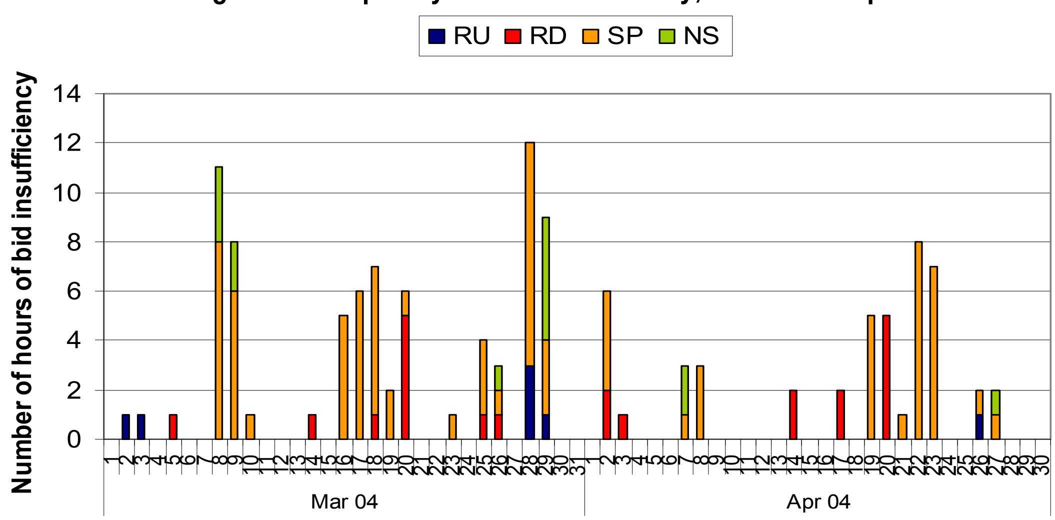
The following chart shows the impact of the overall supply picture on ancillary service prices. Bid composition for the RU and RD markets favored lower prices than March. The SP markets were skewed toward slightly higher prices. The NS markets appear to have no bias in the overall supply picture. However, the increase in NS prices was driven by high prices in a small number of hours.

Figure 4. A/S Bid Volume by Price Bin through Apr-04



Bid insufficiency decreased by 41% from March to April. Several resources entered the ancillary services markets in April due to increased demand for energy. On April 24, 26 and 27, bid insufficiency was minimal. These were the dates of significant pricing events with prices frequently set by resources not active in the markets in March. Without the addition of capacity from these resources, the frequency of bid insufficiency would have been much higher.

Figure 5. Frequency of Bid Insufficiency, March and April



IV. Interzonal Congestion Market Conditions

- ***Congestion on Path 26 and Palo Verde Persists but Congestion Costs Decrease***

Interzonal Congestion costs totaled $1.6 million in April, a significant decrease from the $4.5 million reported in March. Similar to March, the majority of the congestion costs were incurred on Path 26 and Palo Verde, totaling approximately $0.4 million and $0.5 million, respectively. Other paths with significant positive congestion costs in April included Blythe, Mead, and COI.

Palo Verde was frequently congested, especially in the later part of the month, as market participants attempted to import power from the southwest to serve the unseasonably high Southern California load. The initial day-ahead schedules submitted by scheduling coordinators exceeded the import capacity of the line. Day-ahead congestion prices were generally modest, with an average congestion price of approximately $2/MWh.

Congestion on Path 26 occurred less frequently in April than in March. The maximum capacity in the North-to-South direction was approximately 2,500 MW, derated from 3,000 MW due to area resource maintenance. On several occasions on April 1-2 and April 19-22, the line was further derated to 2,100 MW due to maintenance work. The average day-ahead congestion price was approximately $2/MWh, while the maximum congestion price was $12/MWh. Path 26 is scheduled to be derated through May.

Day-ahead congestion occurred on the Blythe intertie in the import direction on several peak hours from April 26 to 29, with an average congestion price of $66/MWh. While Blythe was derated slightly, one FTR holder on the path did not adjust its schedule accordingly, resulting in high congestion prices.

Import capacity on the California-Oregon Intertie (COI) fluctuated widely in April from 2,500 MW to 4,800 MW, due to scheduled maintenance work. Also, the import capacity on the Pacific DC Intertie (also referred to as the North-of-Oregon Border Intertie, or NOB) was partially rerated on April 10 to 1,320 MW, from its derate level of 725 MW. The following tables show the interzonal congestion frequencies and prices for April 2004

Table 3. Interzonal Congestion Frequencies and Prices, April 2004

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)	
	Import	**Export**	**Import**	**Export**	**Import**	**Export**	**Import**	**Export**
BLYTHE	3	0	$66		1	0	$51	
CASCADE	3	0	$0		15	0	$0	
COI	24	0	$0		21	0	$4	
ELVERTA-HURLEY	0	0			0	0		$30
LUGO-IPP (DC)	0	0			0	0	$30	
MEAD	3	0	$8		4	0	$26	
NOB (PAC. DC INTERTIE)	6	0	$1		8	0	$17	
PALO VERDE	17	0	$2		6	0	$6	
PARKER	0	0			0	0	$40	
PATH 15	0	0			0	0	$0	
PATH 26	0	15		$2	0	8		$8
SUMMIT	2	0	$0		0	0	$0	

Table 4. Interzonal Congestion Costs, April 2004

Branch Group	**Day-ahead**		**Hour-ahead**		**Total Congestion Cost**		**Total Congestion Cost**		**Total Congestion Cost**
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead	
BLYTHE	$254,200	$0	$0	$0	$254,200	$0	$254,200	$0	$254,200
CASCADE	$0	$0	$0	$0	$0	$0	$0	$0	$0
COI	$71,928	$0	$20,033	$0	$91,960	$0	$71,928	$20,033	$91,960
ELVERTA-HURLEY	$0	$0	$0	$26,342	$0	$26,342	$0	$26,342	$26,342
LUGO-IPP (DC)	$0	$0	$543	$0	$543	$0	$0	$543	$543
MEAD	$155,693	$0	$12,434	$0	$168,127	$0	$155,693	$12,434	$168,127
NOB (PAC. DC INTERTIE)	$17,898	$0	$17,038	$0	$34,936	$0	$17,898	$17,038	$34,936
PALO VERDE	$608,645	$0	$6,602	$0	$615,246	$0	$608,645	$6,602	$615,246
PARKER	$0	$0	$3,735	$0	$3,735	$0	$0	$3,735	$3,735
PATH 15	$0	$0	$10	$0	$10	$0	$0	$10	$10
PATH 26	$0	$425,312	$0	$4,966	$0	$430,278	$425,312	$4,966	$430,278
Total	$1,108,363	$425,312	$60,394	$31,307	$1,168,757	$456,619	$1,533,675	$91,701	$1,625,377

V. Firm Transmission Rights (FTR) Market Conditions

FTR scheduling. The FTRs auctioned in 2003 expired on March 31, 2004. As of April 1, 2004, a new FTR cycle became effective, using the FTRs auctioned in February 2004. Most FTRs in the current cycle will be effective from April 1, 2004 to March 31, 2005. The exception is the FTRs on COI, which will be effective until December 31, 2004, due to uncertainty surrounding contract negotiations for transmission rights on that path.

FTRs can be used to hedge against high congestion prices and establish scheduling priority in the day-ahead market. As shown in the following tables, a high percentage of FTRs was scheduled on some paths (84% on El Dorado, 53% on IID-SCE, 80% on Lugo-IPP (DC), 52% on Lugo-Mona, 43% on Palo Verde, 98% on Silver Peak in the import direction, and 31% on Path 26). Southern California Edison Company (SCE1) and municipal utilities primarily own the FTRs on these paths.

Table 5. FTR Scheduling Statistics for April, 2004*

Direction	Branch Group	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% FTR Schedule
Import	BLYTHE	168	24	167	167	14%
Import	ELDORADO	536	451	536	536	84%
Import	IID-SCE	600	319	415	395	53%
Import	LUGO-IPP (DC) **	370	294	370	235	80%
Import	LUGO-MONA **	160	84	88	50	52%
Import	LUGO-WESTWING **	93	29	42	28	31%
Import	MEAD	624	25	51	26	4%
Import	NOB (PAC. DC INTERTIE)	725	55	148	100	8%
Import	PALO VERDE	1,021	437	778	613	43%
Import	SILVER PEAK	10	10	10	10	98%
Import	VICTORVILLE	921	14	25	25	2%
Import	COI	617	118	550	550	19%
Export	LUGO-MARKETPLACE **	247	3	5	5	1%
Export	LUGO-MONA **	543	11	60	60	2%
Export	NOB (PAC. DC INTERTIE)	722	14	81	81	2%
Export	PATH 26	1,141	349	872	502	31%

*only those paths on which 1% or more of FTRs were attached are listed.
** The FTRs on these paths were granted to municipal utilities that converted their transmission lines to ISO operation. Thus, they were not released in the primary auction.

FTR Revenue per Megawatt.   The following table summarizes the FTR revenue for April, the first month of the FTR cycle. The FTR revenue was significant on Blythe in the import direction, about $1,395/MW as a result of the day-ahead price spikes on April 26-29. FTR revenues on other paths were fairly modest.

Table 6. FTR Revenue Per MW ($/MW), April 2004

Direction	Branch Group	Net $/MW FTR Rev	FTR Auction Clearing Price ($/MW)
IMPORT	BLYTHE	1,395	8,759
IMPORT	COI	100	26,964
IMPORT	LUGO-IPP (DC)*	1	N/A
IMPORT	MEAD	204	14,775
IMPORT	NOB (PAC. DC INTERTIE)	31	19,050
IMPORT	PALO VERDE	296	24,346
IMPORT	PARKER	29	240
IMPORT	PATH 15	0	7,035
EXPORT	PATH 26	213	19,113

* 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 Auction for 2004-2005. The ISO creates a primary market for FTRs by auctioning them each year. For the 2004-2005 FTR cycle, the primary auction was held and completed in February. As noted above, with the exception of those on COI, the FTRs released in the primary auction are valid through March 31, 2005.[3]

In this primary auction, FTRs on 25 directional branch groups were auctioned. The 2004 auction was the first in which the ISO released FTRs on Parker and Path 15 in the import direction and on Summit in the export direction. In total, the ISO successfully auctioned 11,491 MW of FTRs, with total auction revenue of $101 million, similar to the revenue collected in the 2003 auction. On the branch group level, the revenue on Palo Verde in the import direction decreased from $53 million in 2003 to $24 million in 2004. Meanwhile, revenues from FTRs on other frequently congested paths, such as COI (import), NOB (import), and Path 26 (North-South), all increased. FTR revenue on Path 26 in the North-South direction increased from $12 million in 2003 to $22 million in 2004. The changes in FTR auction revenues on different paths reflected the patterns of congestion in the past year.

As in the previous auction, one discernible pattern in the FTR auction results was that utilities own most FTRs on branch groups that are likely to be congested. For instance, Pacific Gas & Electric won 93 percent of FTRs on COI in the import direction, while Southern California Edison won 100, 84, 60, 100, and 68 percent of FTRs on El Dorado (import), Mead (import), Palo Verde (import), Silver Peak (import), and Path 26 (north to south), respectively. As the principal transmission owners (PTOs) of these paths, the utilities are also the recipients of the auction revenues. This allows them to bid very aggressively to ensure they acquire the quantity of FTRs they require to serve their retail customers without significant exposure to the spot congestion markets. This may have an inflationary effect on FTR auction clearing prices.

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[3] There was a concern that private bid information had been exposed during the auction. After careful reviews conducted by different departments in the ISO including DMA, no evidence was found to support that the FTR auction was compromised by the information leak. The auction was resumed and completed.

Table 7. Summary of 2004-2005 FTR Auction Results

Direction	Branch Group	Auction Clearing Price ($/MW)	Total FTR Sold	Auction Revenue ($)
import	BLYTHE (LC2-SP15)	8,759	168	1,471,512
import	CFE (MX-SP15)	2,360	100	236,000
import	COI (NW1-NP15)	26,964	617	16,636,788
import	ELDORADO (AZ2-SP15)	11,646	536	6,242,256
import	IID-SCE (II1-SP15)	390	600	234,000
import	IID-SDGE (II2-SP15)	1,245	62	77,190
import	MEAD (LC1-SP15)	14,775	554	8,185,350
import	NOB (PAC. DC INTERTIE) (NW3-SP15)	19,050	556	10,591,800
import	PALO VERDE (AZ3-SP15)	24,346	996	24,248,616
import	PARKER (LC3-SP15)	240	130	31,200
import	PATH 15 (ZP26-NP15)	7,035	1,535	10,798,725
import	SILVER PEAK (SR3-SP15)	1,500	10	15,000
import	VICTORVILLE (LA4-SP15)	195	921	179,595
export	BLYTHE (SP15-LC2)	100	72	7,200
export	CFE (SP15-MX)	680	100	68,000
export	COI (NP15-NW1)	135	573	77,355
export	ELDORADO (SP15-AZ2)	100	536	53,600
export	IID-SDGE (SP15-II2)	1,237	62	76,694
export	MEAD (SP15-LC1)	195	579	112,905
export	NOB (PAC. DC INTERTIE) (SP15-NW3)	125	564	70,500
export	PALO VERDE (SP15-AZ3)	100	940	94,000
export	PATH 26 (ZP26-SP15)	19,113	1,141	21,807,933
export	SILVER PEAK (SP15-SR3)	145	10	1,450
export	SUMMIT (NP15-SR2)	625	15	9,375
export	VICTORVILLE (SP15-LA4)	100	114	11,400
Total			11,491	101,338,444

Table Column Definition:

Auction Clearing Price: This is the market-clearing price in $/MW per year. For the paths with seed price > $100/MW per year, the comparison of the Auction Clearing Price and Seed Price* 5 indicates to what extent the bidders value the FTRs on the particular path and direction compared to the congestion revenues generated last year.

Total FTR Sold: This is the final MW clearing the auction. The difference between Total FTR Auctioned and Final MW sold can be either due to some FTRs not sold or the residual FTR allocation option exercised in the auction.

Auction Revenue: this is equal to the product of Auction Clearing Price and Final MW Sold.

Table 8. FTR Concentration as of April 2004 *

Direction	Branch Group	Owner ID	Owner Name	% Conc.	Max FTRs Owned	Total FTRs quantity
EXP	BLYTHE	MSCG	Morgan Stanley Capital Group, Inc.	50	36	72
	BLYTHE	CEPL	Citadel Energy Products LLC	33	24	72
	CFE	SEES	Sempra Energy Solutions	100	100	100
	COI	MSCG	Morgan Stanley Capital Group, Inc.	39	223	573
	ELDORADO	MSCG	Morgan Stanley Capital Group, Inc.	50	268	536
	IID-SDGE	CEPL	Citadel Energy Products LLC	55	34	62
	IID-SDGE	MSCG	Morgan Stanley Capital Group, Inc.	45	28	62
	LUGO-MARKETPLACE	RVSD	City of Riverside	43	106	247
	LUGO-MARKETPLACE	ANHM	City of Anaheim	26	63	247
	LUGO-MONA	ANHM	City of Anaheim	64	350	543
	LUGO-MONA	RVSD	City of Riverside	36	193	543
	LUGO-WESTWING	ANHM	City of Anaheim	51	47	93
	LUGO-WESTWING	VERN	City of Vernon	30	28	93
	MEAD	MSCG	Morgan Stanley Capital Group, Inc.	34	210	613
	MEAD	ECH1	Dynegy Power Marketing, Inc.	27	163	613
	NOB (PAC. DC INTERTIE)	MSCG	Morgan Stanley Capital Group, Inc.	35	254	722
	PALO VERDE	MSCG	Morgan Stanley Capital Group, Inc.	49	470	965
	PATH 26	SCE1	Southern California Edison Company	68	771	1141
	PATH 26	SDG3	San Diego Gas & Electric, Merchant	32	370	1141
	SILVER PEAK	MSCG	Morgan Stanley Capital Group, Inc.	50	5	10
	SILVER PEAK	CEPL	Citadel Energy Products LLC	50	5	10
	SUMMIT	SETC	Sempra Energy Trading Corporation	67	10	15
	SUMMIT	PWRX	British Columbia Power Exchange	33	5	15
	SYLMAR-AC	BAN1	City of Banning	60	15	25
	SYLMAR-AC	AZUA	City of Azusa	40	10	25
	VICTORVILLE	MSCG	Morgan Stanley Capital Group, Inc.	50	57	114
	VICTORVILLE	WESC	Williams Energy Marketing and Trading	41	47	114

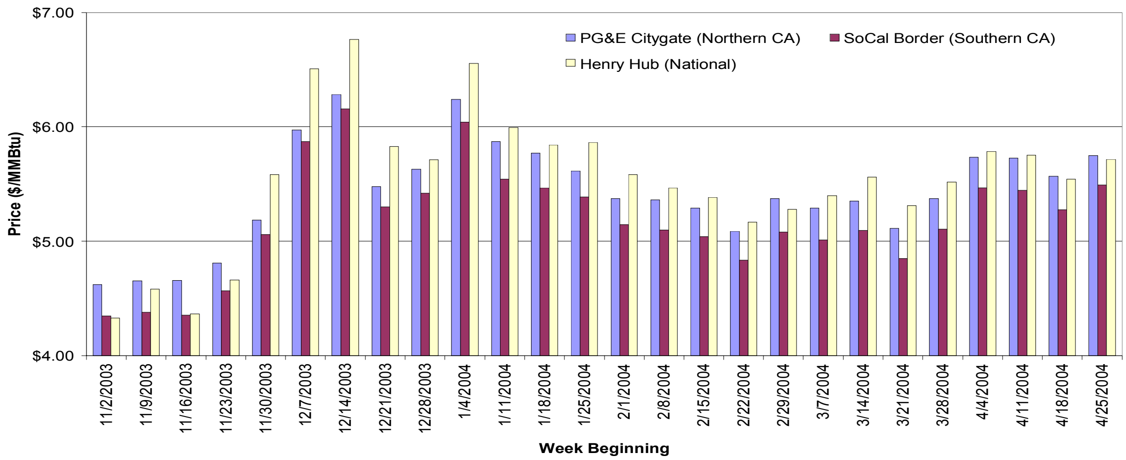
Direction	Branch Group	Owner ID	Owner Name	% Conc.	Max FTRs Owned	Total FTRs quantity
IMP	BLYTHE	FPPM	FPL Energy Power Marketing, Inc.	99	167	168
	CFE	SDG3	San Diego Gas & Electric, Merchant	100	100	100
	COI	PCG2	Pacific Gas & Electric Company-PCG2	93	574	617
	ELDORADO	SCE1	Southern California Edison Company	100	536	536
	IID-SCE	SCE1	Southern California Edison Company	77	460	600
	IID-SDGE	SDG3	San Diego Gas & Electric, Merchant	81	50	62
	LUGO-GONDER	ANHM	City of Anaheim	100	4	4
	LUGO-IPP (DC)	ANHM	City of Anaheim	64	235	370
	LUGO-IPP (DC)	RVSD	City of Riverside	36	135	370
	LUGO-MARKETPLACE	RVSD	City of Riverside	43	106	247
	LUGO-MARKETPLACE	ANHM	City of Anaheim	26	63	247
	LUGO-MONA	ANHM	City of Anaheim	63	100	160
	LUGO-MONA	RVSD	City of Riverside	38	60	160
	LUGO-WESTWING	ANHM	City of Anaheim	51	47	93
	LUGO-WESTWING	VERN	City of Vernon	30	28	93
	MEAD	SCE1	Southern California Edison Company	84	525	624
	NOB (PAC. DC INTERTIE)	TEMU	TransAlta Energy Marketing (U.S.) Inc	41	300	725
	PALO VERDE	SCE1	Southern California Edison Company	60	613	1021
	PARKER	MSCG	Morgan Stanley Capital Group, Inc.	45	58	130
	PARKER	SETC	Sempra Energy Trading Corporation	28	37	130
	PATH 15	PCG2	Pacific Gas & Electric Company-PCG2	100	1535	1535
	SILVER PEAK	SCE1	Southern California Edison Company	100	10	10
	SYLMAR-AC	AZUA	City of Azusa	57	20	35
	SYLMAR-AC	BAN1	City of Banning	43	15	35
	VICTORVILLE	MSCG	Morgan Stanley Capital Group, Inc.	36	335	921
	VICTORVILLE	ANHM	City of Anaheim	30	275	921

***** Only FTR ownership concentrations at or more than 25% are reported in the table.
The total of FTR quantities on some branch groups may be greater than the amount auctioned in the primary auction. This is due to the fact that additional FTRs on these paths were awarded to municipal utilities that converted their lines to the ISO. For the same reason, FTRs are created and awarded on some other branch groups which were not part of the primary auction.

VI. Natural Gas Market Conditions

Higher average temperatures in April, and in particular the aforementioned record setting temperatures in the last week of April exceeding 100° F in Southern California, resulted in higher cooling demand and higher natural gas prices than in March. While temperatures during the first four days of April resembled those at the end of March, prices increased in step with temperature in Northern California during the first full week of April, and reached a weekly average of $5.76/MMBtu at the PG&E Citygate pricing point. Prices remained in this neighborhood through the second week of April. Prices were slightly lower during the third week, but reached monthly highs during the last week of April due to triple-digit temperatures. Average daily gas prices for March were $5.71/MMBtu at Henry Hub, $5.26/MMBtu at Malin, $5.68/MMBtu at PG&E Citygate, and $5.41/MMBtu at Southern California Border. Average bid week prices for May were $5.38, $5.26, and $5.80/MMBtu for SoCal Gas, Malin, and PG&E Citygate, respectively, up 10%, 11%, and 12% from April bid week prices. The following chart shows weekly average gas prices at regional delivery points through March.

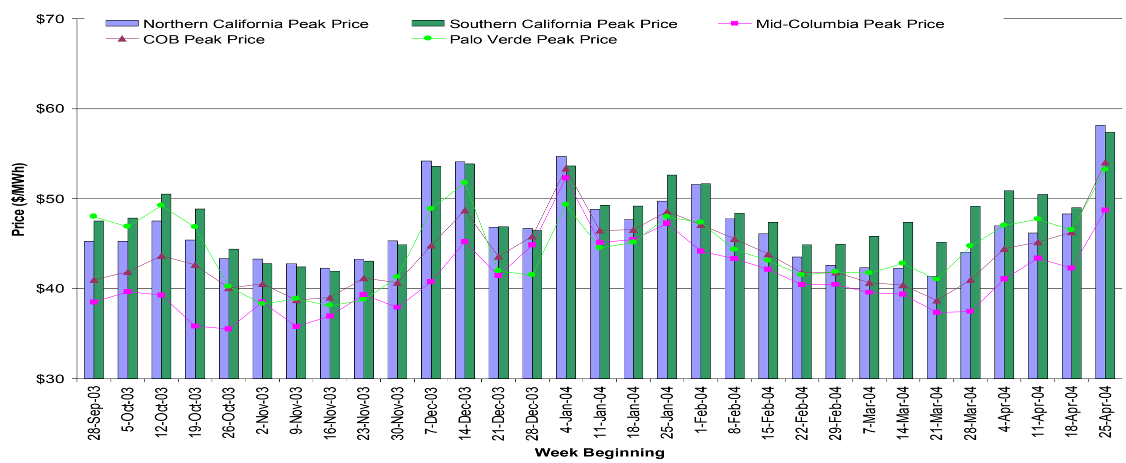
Figure 6. Weekly Average Natural Gas Prices at Regional Delivery Points through April



VII. Day-Ahead Bilateral Electricity Market Conditions

Day-ahead electricity prices reflected the increases in natural gas prices and cooling demand, particularly in the West, and were higher than March average prices. Southern California prices were higher than Northern California prices during the first half of April, after which the two California prices were similar. The last week of April showed a dramatic price increase due to the extremely warm temperatures and high natural gas prices in California. Also driving the prices were system warnings issued by the ISO on April 25 and restricted maintenance notices issued on April 25 and 26. Average April peak weekday regional day-ahead electricity prices were $46.44/MWh at the California-Oregon Border, $43.42/MWh at Mid-Columbia, $48.18/MWh at Palo Verde, $48.73/MWh in Northern California, and $50.88/MWh in Southern California.

Figure 7. Weekly Average Day-Ahead Bilateral Electricity Prices through April



VIII. Issues under Review

Transmission Evaluation Methodology. The 2013 cost-based case for Path 26 was completed after extensive iterations. The 2008 sensitivity cases were also completed and sensitivity analysis for 2013 has begun. Development has begun on a report to the CPUC describing the methodology and results analyzing and upgrade to Path 26. The Market Surveillance Committee continues to provide input into the methodology and will provide an opinion within the next few weeks.