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 Assistants

Date: July 23, 2004

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

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

Executive Summary

Unseasonably mild weather throughout California during June 2004 resulted in a monthly peak load 4.7 percent lower than June 2003. However, average daily peaks and minimum load levels increased 6.9 and 6.1 percent, respectively, between June 2003 and 2004, due in part to a more robust economy and continued load growth. Modest peak loads, in combination with unscheduled energy from units committed to mitigate intrazonal congestion pursuant to the "Must-Offer" Obligation, resulted in minimal reliance on the real-time balancing energy market, notably during peak-load afternoon hours. Incremental and decremental balancing energy prices averaged $61.39 and $26.22/MWh, respectively.

Meanwhile, the combination of growth in scheduled imports and deratings of some of the major interties into California due to scheduled maintenance resulted in total inter-zonal congestion costs of $6.1 million in June, the highest level since 2002. On the other hand, intra-zonal (within zone) congestion costs were at the lowest level since the start-up of new generation in Mexicali, Mexico last summer. Lower intra-zonal congestion costs are due to maintenance[1] as well as upgrades to the transmission network within Southern California. Total intra-zonal congestion re-dispatch costs in June were $1.7 million, compared to $3.7 million in May.

Low off-peak overnight loads often result in numerous units operating near their minimum levels during those hours. This has a side effect of decreasing the volume of generation that can economically provide regulation ancillary services. Consequently, off-peak supply shortages for regulation services have occurred throughout June, and have resulted in off-peak prices approximately 50 percent above those seen in May.

[1] As part of the planned upgrade to the Miguel substation, series capacitor banks on the Southwest Power Link ("SWPL") line feeding into Miguel have been taken out of service so that new banks can be installed. This has temporarily increased the impedance of the line, diverting power flows away from this frequently constrained area.

A large (4,000 MW) cascading outage of generators occurred on June 14, including the three units at the Palo Verde nuclear station and other units in Arizona and Alberta, Canada. This event had minimal impact on the CAISO's real-time balancing energy market. The real-time incremental price peaked during the event at $79.98/MWh, a level that is not unusual during weekday afternoons. However, hour-ahead Interzonal congestion prices in the region reached as high as $391/MWh, due to transmission derates resulting from the outages.

I. Trends Affecting Market Demand and Supply

Loads. Peak loads in June 2004 were considerably lower than those in June 2003. However, average and daily-minimum loads were substantially higher. June continued the trend of load growth that has been evident since the third quarter of 2003. Because the weather was mild, this increase in load was likely due to growth in the economy and/or population. The June 2004 peak of 38,233 MW was modest for this time of year, 4.7 percent lower than the June 2003 peak of 40,117 MW. Average energy usage, however, was 28,676 MW, 6.6 percent above the June 2003 level of 26,913 MW**.** Daily-minimum load levels, or "troughs", when energy use is at its lowest in the middle of the night, was 6.1 percent greater in June 2004 than in June 2003. The trough statistic is informative because the impact of differences in weather should be minimal this time of day. Figure 1 compares loads in June 2003 and June 2004. Table 1 shows load growth rates in average usage, daily peaks, daily troughs, and monthly peaks.

Figure 1. Comparison of Hourly Actual Loads: June 2004 v. June 2003

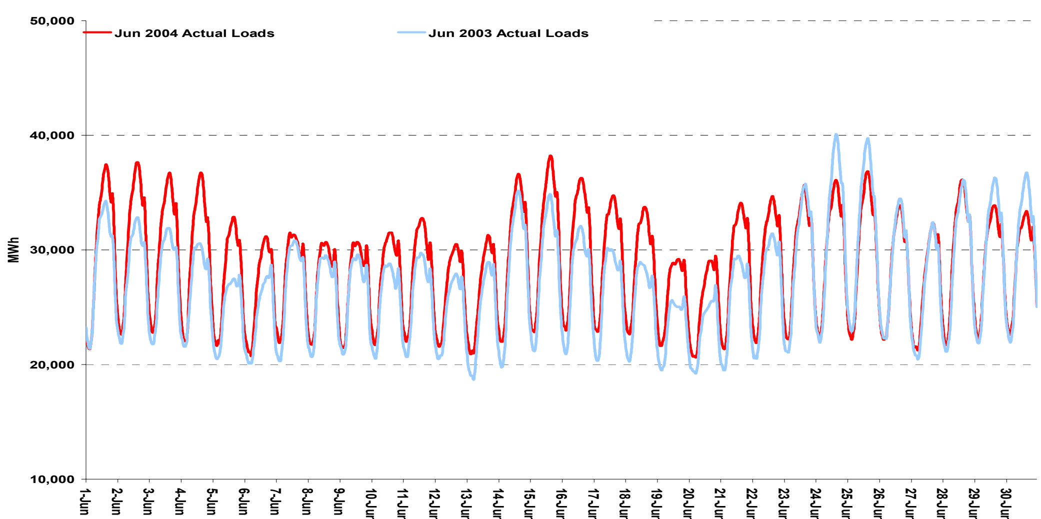


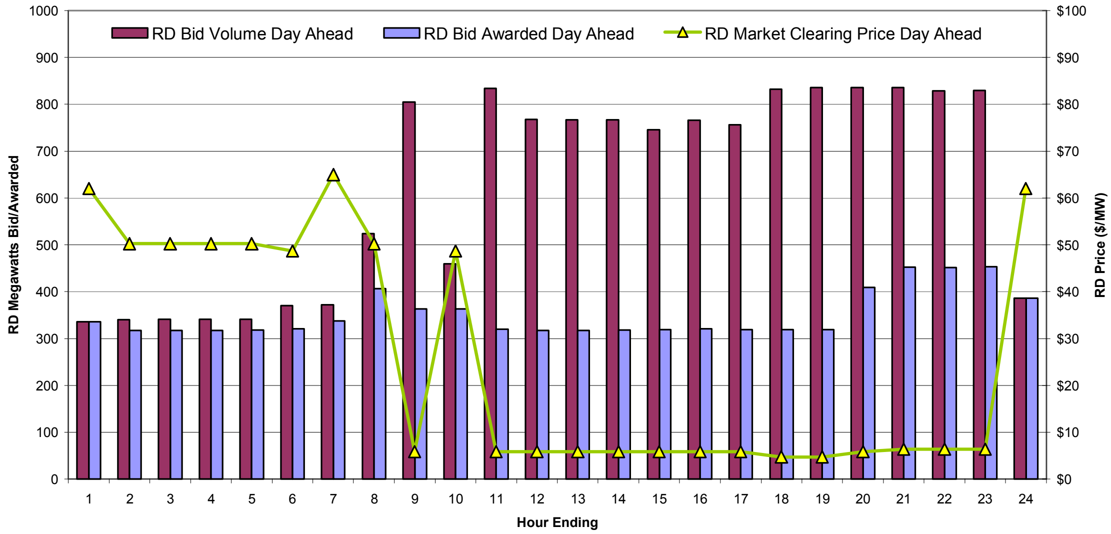
Table 1. Load Growth Compared to Same Months in Prior Year: Monthly through June 2004

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
July-03	4.3%	6.9%	0.1%	0.5%
August-03	5.4%	8.5%	1.5%	4.3%
September-03	2.2%	3.3%	0.2%	0.3%
October-03	5.4%	7.0%	2.6%	3.7%
November-03	-0.2%	1.0%	-0.8%	0.2%
December-03	2.8%	3.1%	1.5%	2.7%
January-04	4.3%	3.1%	5.1%	3.2%
February-04	4.5%	3.9%	5.4%	4.5%
March-04	4.4%	5.1%	2.5%	4.5%
April-04	7.1%	8.3%	4.8%	31.1%
May-04	7.3%	7.7%	5.5%	2.5%
June-04	6.6%	6.9%	6.1%	-4.7%

Notes: Through 7/10/03: Actual loads at top of hour. Since 7/11/03: Hourly average loads.

Ancillary Services Bid Sufficiency. While loads in off-peak periods have been higher than in previous years, they remain considerably less than peak loads. Below normal hydro conditions in California have resulted in some hydroelectric resources that provide a large portion of regulation capacity shutting down during off-peak hours to conserve water supplies. This contributes to the problem of bid insufficiency in those hours where there is insufficient supply offered into the ancillary service markets to meet the CAISO's reserve requirements. Figure 2 illustrates this phenomenon by comparing day-ahead downward regulation bid volume to procurement requirements, and showing the resultant market prices, for each hour on June 25, 2004.

Figure 2. Hourly Downward Regulation Bid Volume and Awarded Requirement v. Market-Clearing Prices: June 25, 2004[2]



Inter-zonal Congestion and Imports. Deratings of the California-Oregon Intertie (COI) and the Pacific DC Intertie (NOB) caused congestion on imports into California from the Pacific Northwest. Meanwhile, growth in import traffic on these ties, and on the Palo Verde Intertie, which connects California to generation in the Southwest, caused both total absolute imports and total congestion costs to reach their highest levels since 1999. Imports from both the Northwest and the Southwest increased between June 2003 and June 2004. They were offset slightly by an increase in exports to the Sacramento Municipal Utility District (SMUD). Figures 2 and 3 show inter-zonal congestion and monthly average imports, exports and net imports since January 2003.

[2] Portions of bids may not be feasibly awarded due to ramping constraints. Thus, this chart may show greater sufficiency than is actually the case.

Figure 3. Monthly Total Interzonal Congestion Costs since Jan-03

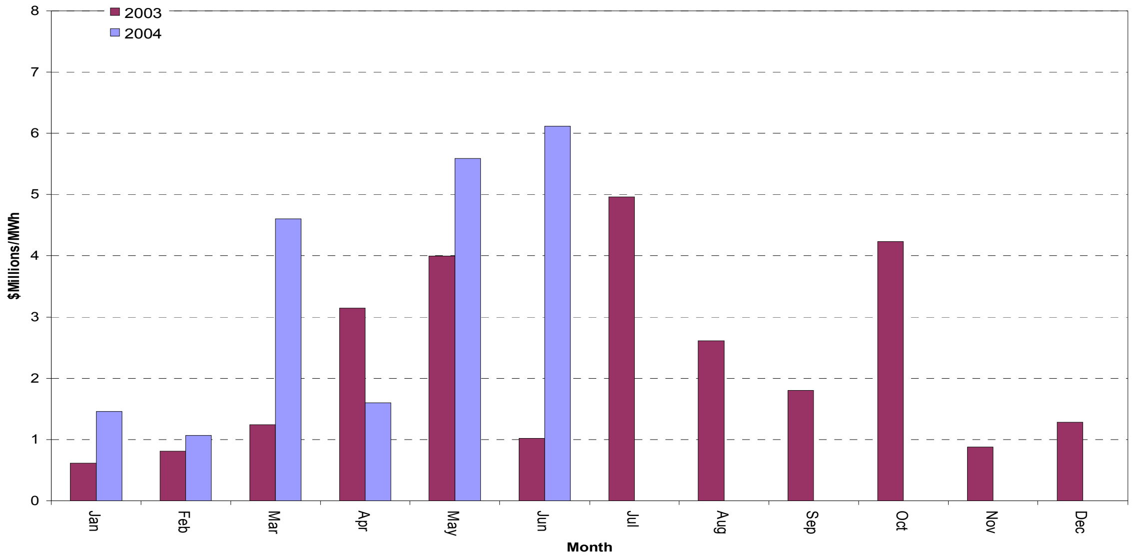
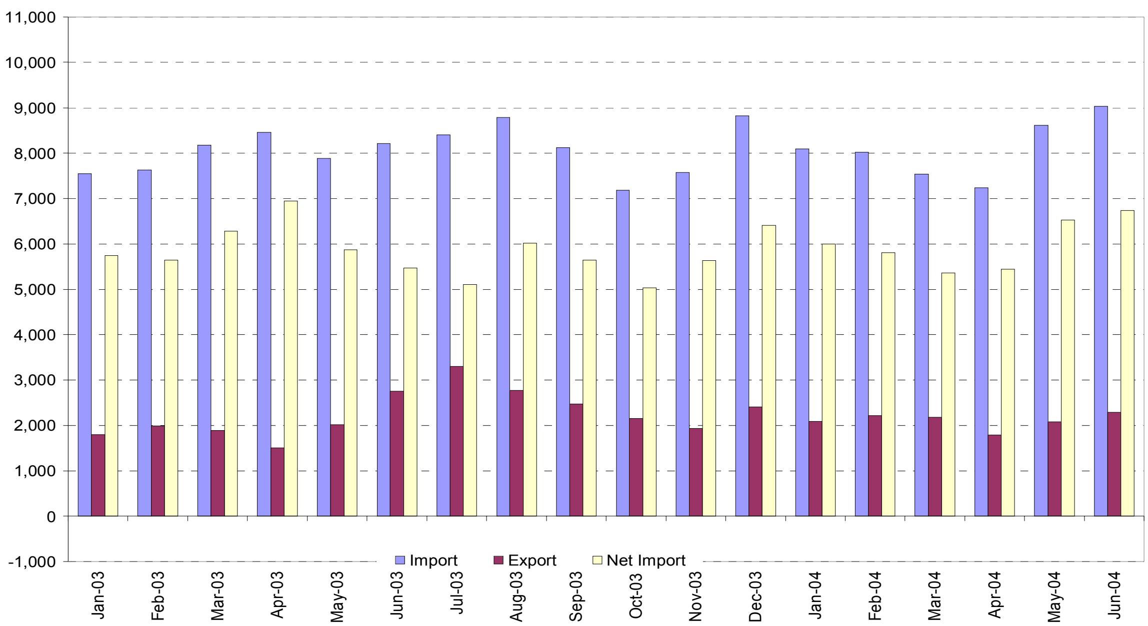
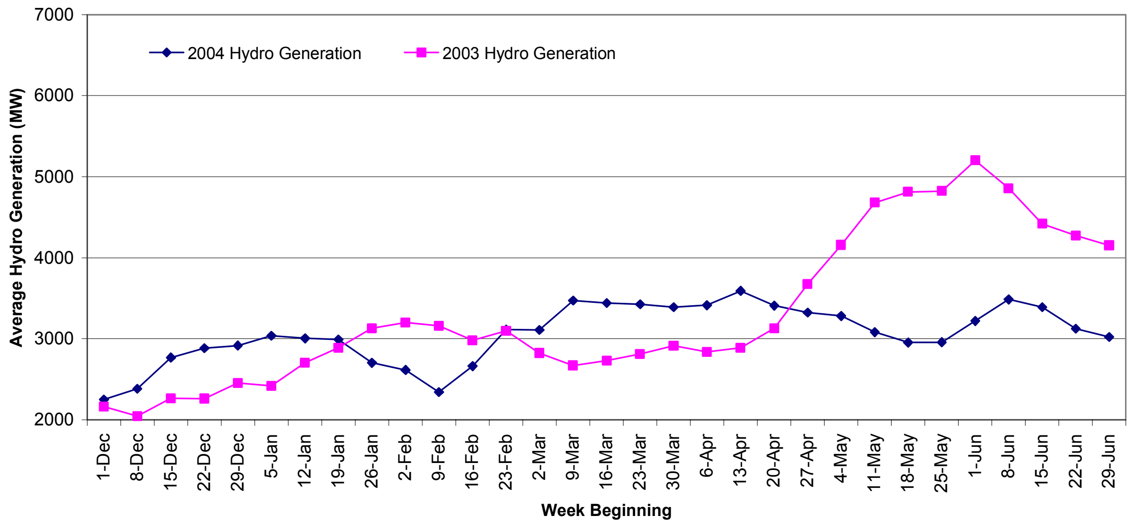


Figure 4. Imports, Exports, and Net Imports, Since Jan-03



Hydroelectric Production. The most productive part of the hydro season was brief in 2004, and had begun to subside by June. Figure 4 shows that hydroelectric production during the 2004 season has been at least 1000 MW less than the 2003 season on average, due to early season snowfall and a very warm spring.

Figure 5. Approximate Weekly Average Hydroelectric Production in California: 2002-03 and 2003-04 Seasons



II. Real-Time Market Performance

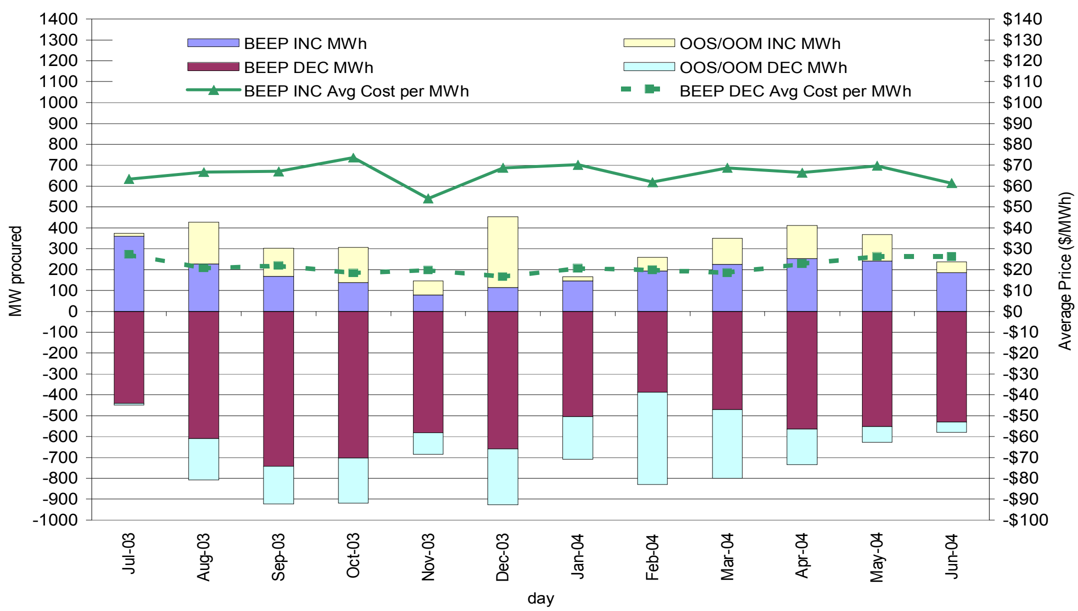
- ***Minimal activity in real-time balancing energy market***
- ***Intra-zonal congestion costs at Miguel Substation down due to maintenance work***
- ***Intra-zonal congestion costs at Lugo Substation and due to SCIT down due to transmission upgrade***

Prices for real-time balancing energy were moderate in June, a quiet month for the market overall. The average price for incremental ("INC") balancing energy, the price the CAISO pays to generators to provide energy in excess of their forward schedules when load exceeds the total of those schedules, was $61.40/MWh in June, compared to $69.83/MWh in May. Meanwhile, the average price for decremental ("DEC") balancing energy, the price generators pay to the CAISO to reduce generation output, was $26.22/MWh in June, compared to $26.17/MWh in May. INC and DEC total energy dispatch volumes were 134 and 385 gigawatt-hours (GWh), respectively, a substantial decrease from the May levels of 179 and 410 GWh. As has been the case since the summer of 2003, decremental volume has persistently exceeded incremental volume. The CAISO must offset unscheduled energy from units such as those held online at minimum load pursuant to the Must-Offer Obligation, many for the purpose of managing intra-zonal congestion within Southern California. Redispatch premium uplift costs to manage intra-zonal congestion totaled $1.7 million in June, compared to $3.7 million in May. Table 2 shows volume-weighted average real-time prices, total dispatched energy, and average system loads and underscheduling in June. Figure 5 shows average hourly prices and volumes of balancing energy for the 12 months ending in June.

Table 2. Average Real-Time Prices, Total Energy, and Average Loads and Underscheduling in June 2004

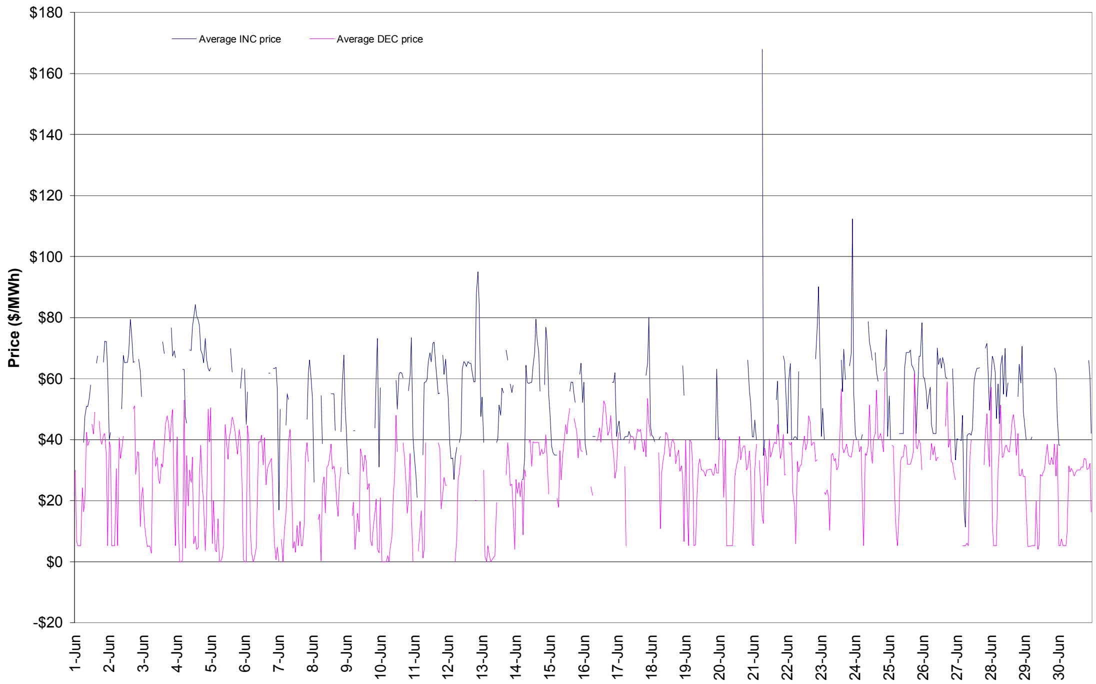
	Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$ 65.67	$ 28.04	31,267 MW
	79,018 MWh	328,544 MWh	2.3%
Off-Peak	$ 55.20	$ 15.57	23,493 MW
	54,676 MWh	56,057 MWh	3.7%
All Hours	$ 61.39	$ 26.22	28,676 MW
	133,694 MWh	384,600 MWh	2.7%

Figure 6. Monthly Average Real-Time Market Prices and Volumes, and OOS/OOM Volumes, through June 2004



Price Spikes. The real-time balancing energy market was calm in June on a system-wide market basis. In particular, despite a severe outage in Arizona of the West Wing-Liberty transmission line (and several associated generation trips in excess of 4,000 MW in that region) on June 14, there were no noticeable effects on real-time energy prices within the CAISO Control Area. Hourly zonal INC prices exceeded $100/MWh only twice in the entire month. DEC prices repeatedly were near zero in the first half of the month. Figure 7 shows system-wide hourly average INC and DEC prices in June.

Figure 7. System-wide Hourly Average Real-Time Prices in June



Between June 4 and 13, a large hydroelectric system faced with having to spill water bid a DEC price near $0/MWh to signal its zero value. This situation has occurred from time to time in recent months, but probably will not occur again this year, given the higher loads that are we are likely to see later this summer.

The CAISO system-wide INC price ranged between $110.86 and $116.22/MWh on June 12, 2004, between 8:50 and 9:20 p.m. (in hours ending 21:00 and 22:00) during unscheduled flow on interties into Southern California. During this spike, a total of 767 MWh was dispatched over three intervals, or an average of 1,535 MW.

On June 21 at 6:21 a.m. a northern California thermal unit tripped. Another unit within NP15 tripped at 6:33 a.m., creating a frequency deviation of 59.901 Hz. The CAISO dispatched all available resources in northern California to recover, as Path 15 was congested in the hour-ahead forward market in the South-to-North direction. Consequently, the real-time incremental price spiked to $210/MWh between 6:30 and 7:00 p.m.[3] This price was set by a hydro resource that had a reference level of approximately $17.50/MWh. However, the price screen threshold[4] precluded AMP from being implemented since the spike could not have been predicted prior to the beginning of the hour

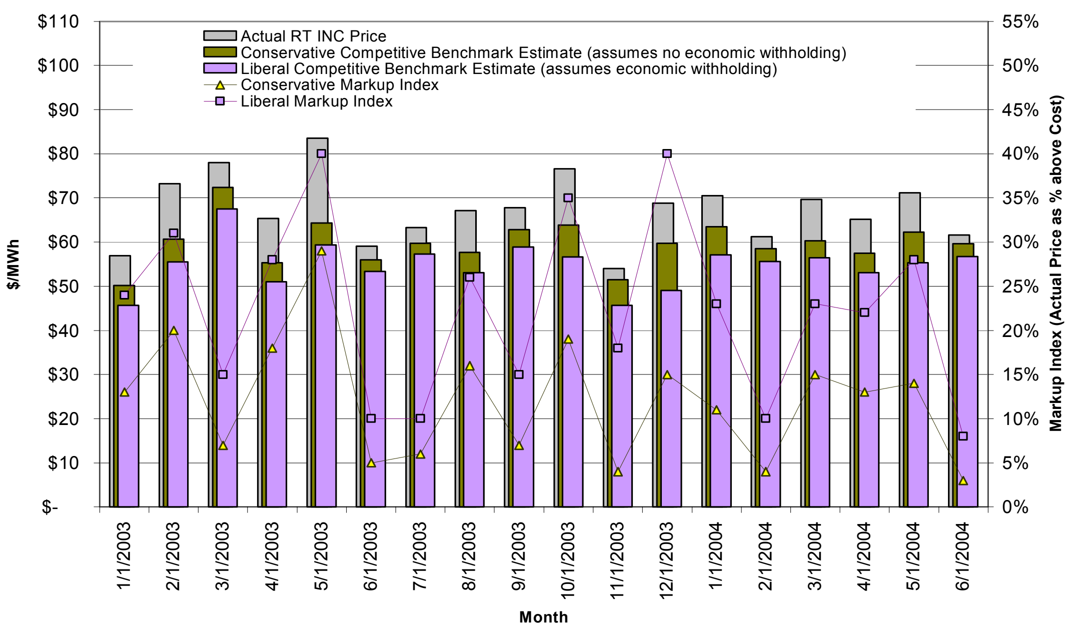
Real-time Market Competitiveness. The real-time price-to-cost markup is an indicator of the competitiveness of the real-time market. The Department of Market Analysis calculates this index

[3] The spike shown in Figure 7 is the systemwide average price, below the zonal price of $210/MWh.
[4] Under the current market power mitigation measures ordered by FERC, AMP is not to be implemented unless the price is predicted to be greater than $91.87/MWh.

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; it assumes that high-priced bids in excess of the market clearing price reflect high costs. This produces a higher estimate of the competitive price and results in a lower estimate of potential markup. The other index accounts for economic withholding by substituting estimated marginal cost-based bids for bids in excess of the market clearing price. This produces a lower estimate of the competitive price and a higher estimate of potential markup.

The price-to-cost markup in incremental balancing energy was considerably less in June, in the range of 3 to 8 percent for the two indices, compared to the range of 13 to 27 percent in May. The eight highest markup hours accounted for over 25 percent of the monthly total markup. The monthly markup was approximately $0.7 million. Figure 8 compares monthly average prices to the two competitive benchmarks, and shows the two markup indices, through June.

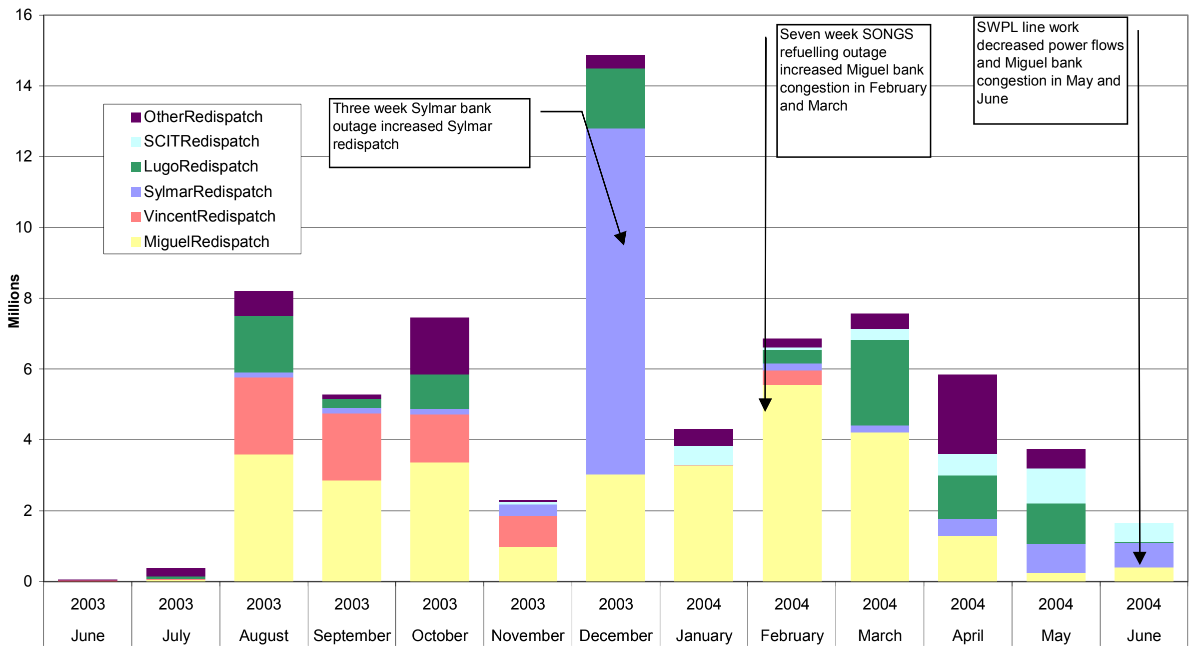
Figure 8. Price-to-Cost Markup in Real-Time Incremental Balancing Energy



Real-Time Intra-zonal Congestion Management. Intra-zonal (within zone) congestion decreased from May with June having significantly smaller volumes of incremental out-of-sequence dispatch energy and slightly less decremental out-of-sequence (OOS) energy. The primary reason for incremental OOS dispatches was constraints at the Sylmar substation due to ongoing maintenance work (74 percent of incremental costs). Transmission was also constrained pursuant to the Southern California Import Transmission nomogram (SCIT, 19 percent of incremental costs), which limits the amount of power that can be simultaneously imported into Southern California. Together, these constraints comprised approximately 93 percent of all incremental out-of-sequence (OOS) re-dispatch costs.

Miguel re-dispatch costs, though much reduced from earlier in the year, comprised the single largest cost category in the month of June for decremental dispatches (48 percent of decremental costs). Ongoing maintenance work on the Southwest Power Link (SWPL), which feeds Southwestern power into the Miguel substation, continued to reduce congestion at Miguel. There were also significant decremental dispatches due to SCIT (42 percent of decremental costs). The following chart shows the intra-zonal congestion re-dispatch costs by month and location.

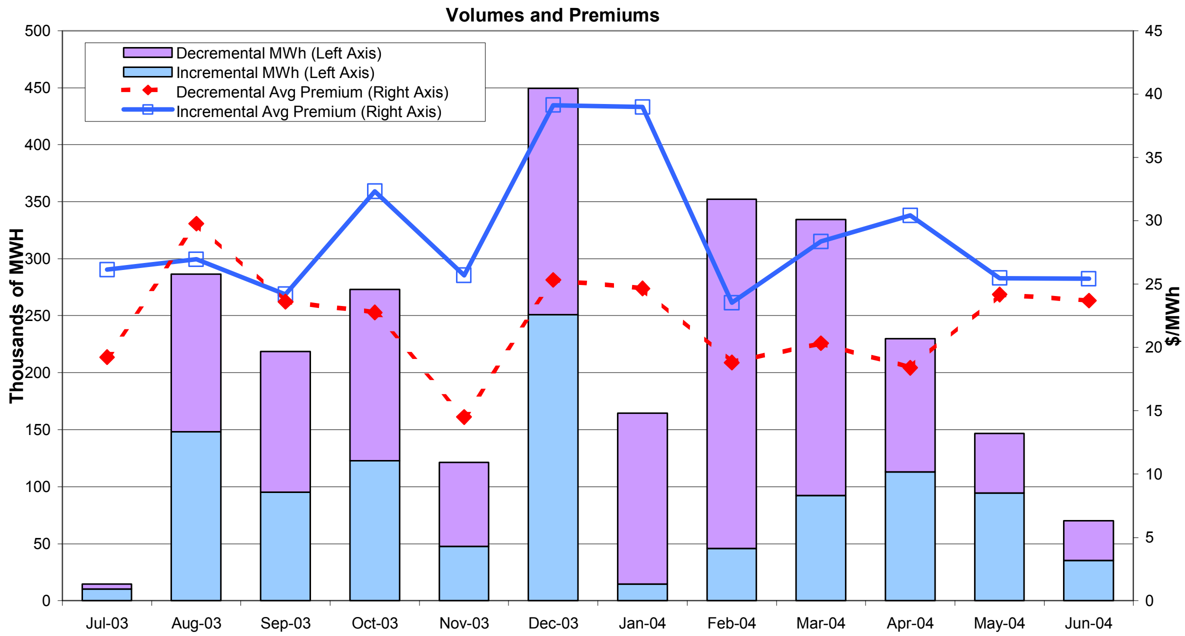
Figure 9. Monthly Total Congestion Costs by Location and/or Cause
Less Congestion at Miguel in May and June due to SWPL Line Maintenance



Overall, June intra-zonal congestion OOS dispatches resulted in a net cost (re-dispatch premium) of approximately $1.7 million compared to $3.7 million in May. Total congestion OOS dispatch volume was 70 GWh (INC plus DEC), and the average re-dispatch premium was $24.57/MWh. Sylmar was the most costly constraint (approximately 41 percent of total re-dispatch costs), followed by SCIT (30 percent), and Miguel (23 percent). Figure 10 illustrates these amounts for recent months.[5]

[5] Congestion net cost or re-dispatch 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.

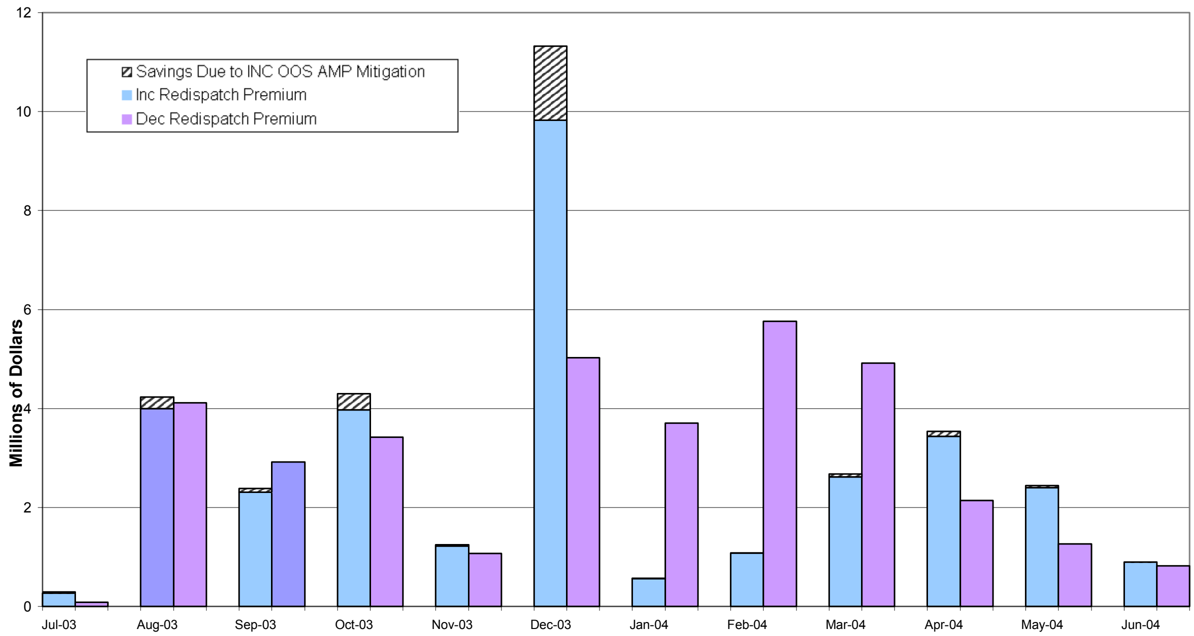
Figure 10. Intrazonal Congestion Volume and Average Re-dispatch Premium



Incremental Intra-zonal Congestion Dispatches. CAISO operators dispatched 35 GWh of incremental energy in June to mitigate intra-zonal congestion. The average price paid was \$64.35/MWh, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately \$0.9 million or \$25.42/MWh. The key points of constraint were the Sylmar Substations and SCIT.

All incremental OOS dispatches are subject to mitigation. Figure 11 shows the re-dispatch premiums for both decremental and incremental congestion as well as the savings due to mitigation of incremental OOS dispatches. Figure 11 shows that very little bid mitigation has taken place due to the large thresholds in AMP for local market power. Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of \$1,596, or 0.2 percent of the total re-dispatch premiums in June.

Figure 11. Intrazonal Re-dispatch Premiums and INC OOS Mitigation Savings

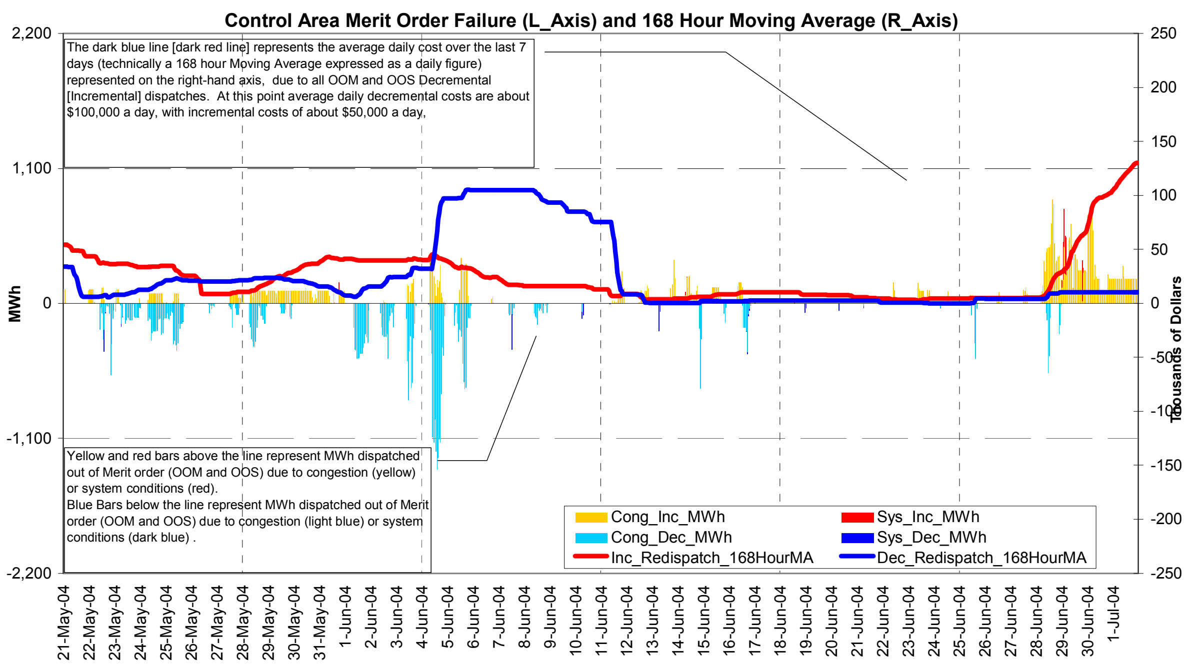


Decremental Intrazonal Congestion Dispatches. A total of 35 GWh of decremental energy was dispatched out of sequence in June. This energy was settled in accordance with the provisions of the FERC-approved Amendment 50 mitigation measures. The approximate re-dispatch premium in excess of the market clearing price was $825,000, or $23.70\MWh. Congestion was a result of the Miguel Bank constraint (accounting for 48 percent of decremental congestion costs) and the SCIT Nomogram (42 percent).

Figure 12 shows the energy dispatched (bar graph on the left axis) and the seven-day daily moving average for the intra-zonal congestion re-dispatch costs. During June, neither incremental nor decremental re-dispatch costs exceeded $150,000 per day, and activity was particularly subdued in the middle two weeks.

The vast majority of the dispatches were due to congestion (labeled Cong_Inc_MWh and Cong_Dec_MWh), with incidental dispatches due to grid conditions, typically over-generation, voltage support or something similar (labeled Sys_Inc_MWh, and Sys_Dec_MWh).

Figure 12. Control Area Out-of-Sequence Dispatch Volumes and Costs, May - June 2004



III. Ancillary Services Market Performance

- ***Overall decrease in supply (2.4 percent) in the A/S markets.***
- ***Overall increase in demand (7.7 percent) and market prices (10.1 percent).***
- ***Overall increase in bid insufficiency (118 percent). Bid insufficiency was concentrated in the regulation down markets.***

Market Prices. Market prices increased in the ancillary services markets from May to June 2004. Overall demand decreased 7.7 percent in June, while overall supply decreased by 2.4 percent. Prices in the regulation up (RU), regulation down (RD) and non-spinning reserve (NS) markets increased, while spinning reserve (SP) prices declined. Table 3 shows ancillary service requirements and prices.

Table 3. Average Ancillary Service Requirements and Prices

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
May 04	373	402	773	744	$ 19.72	$ 13.09	$ 8.16	$ 2.64
Jun 04	390	415	845	819	$ 21.90	$ 16.60	$ 7.48	$ 3.71

The first week of June was the highest priced week for operating reserves (SP, NS). Operating reserve prices declined throughout the month. A few hours of moderately high prices kept the monthly average price of operating reserves from declining. Pricing events like those described for operating reserves in the Market Analysis Report for May 2004 did not recur during June.

Increasing off-peak bid insufficiency in the regulation markets during May spurred a repeating pricing event in each of those markets. Off-peak prices for these products are significantly greater than on-peak prices. During the first two weeks of June, these events were occasional; later they became regular, daily events. During these events regulation up and down prices reached $45-60/MW in the day-ahead market beginning in hour 24 and lasted six to nine hours. On-peak prices were very similar to those observed in May 2004. This pattern began to emerge on June 15 and 16. Since June 17, it has been a daily occurrence.

The impact of these pricing events is evident when looking at weekly average prices in the ancillary services markets shown in Figure 13 below. Regulation prices increased throughout June.

Figure 13. Weekly Weighted Average A/S Prices through June 2004

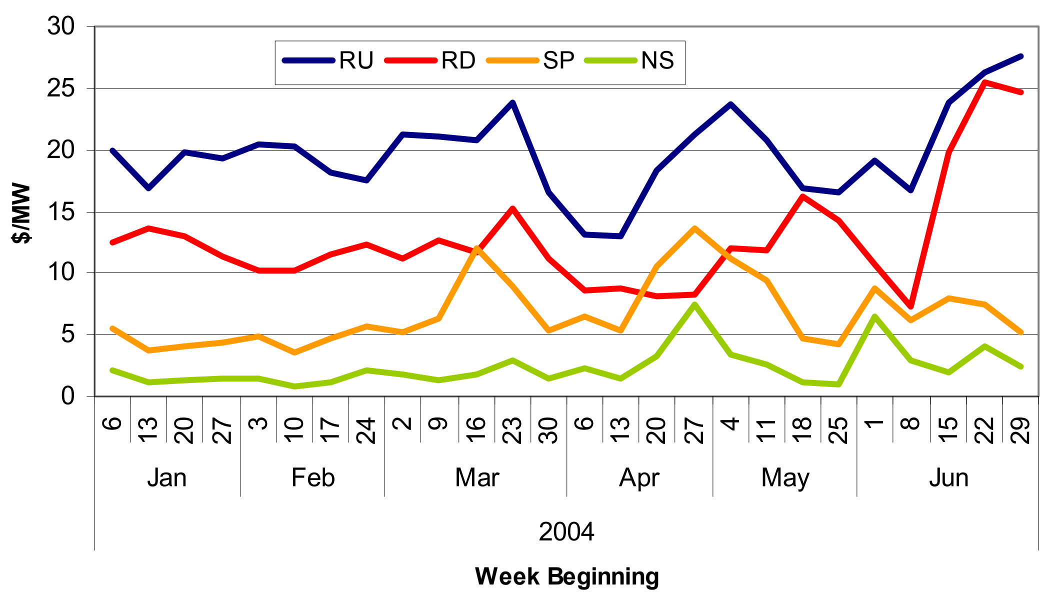


Table 4 shows the change in off-peak pricing of regulation. Off-peak RU and RD prices increased by about $9/MW. On-peak prices changed very little. It is clear that demand for off-peak regulation has not grown substantially. Thus the high off-peak prices are attributable to the decline of off-peak supply and the pricing of off-peak regulation bids.

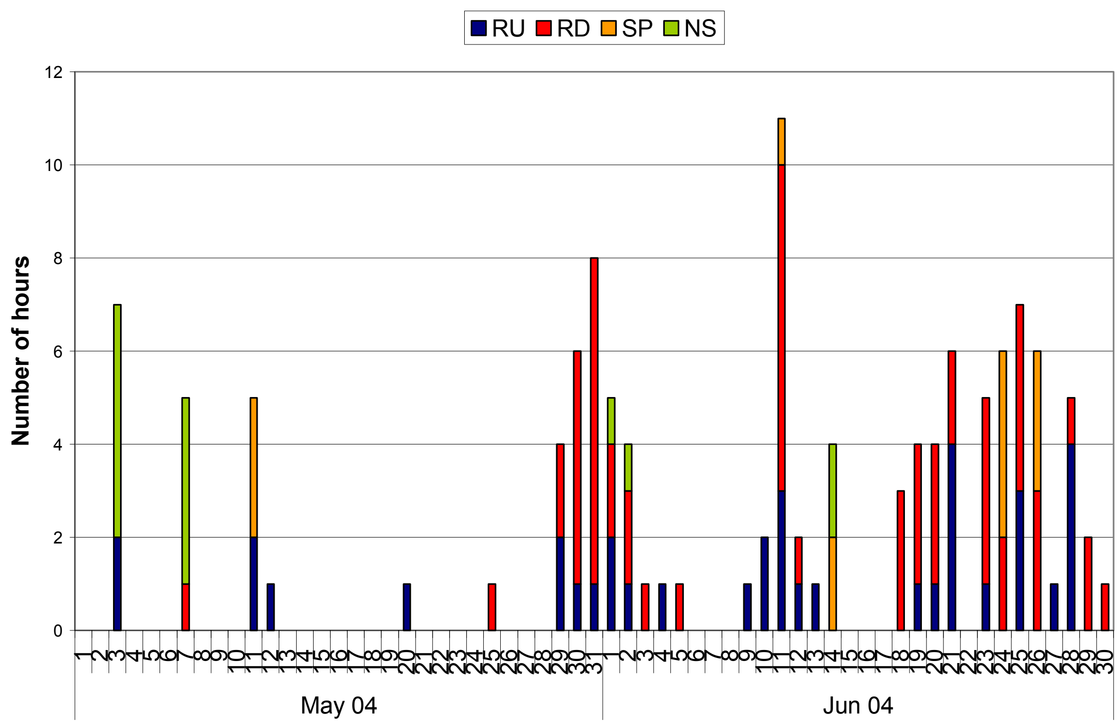
Table 4. Time of Day A/S Demand and Pricing, May - June 2004

		Average AS Procured (MW)			Weighted Average Price ($/MW)		
		On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak	All Hours
May 04	RU	370	380	373	$ 21.42	$ 16.41	$ 19.72
	RD	405	397	402	$ 10.45	$ 18.48	$ 13.09
	SP	797	724	773	$ 10.75	$ 2.47	$ 8.16
	NS	767	699	744	$ 3.37	$ 1.04	$ 2.64
	Total	2339	2199	2292	$ 9.89	$ 7.27	$ 9.05
Jun 04	RU	400	369	390	$ 20.19	$ 25.60	$ 21.90
	RD	420	403	415	$ 11.39	$ 27.47	$ 16.60
	SP	910	715	845	$ 9.61	$ 2.04	$ 7.48
	NS	882	693	819	$ 4.80	$ 0.94	$ 3.71
	Total	2612	2180	2468	$ 9.81	$ 10.28	$ 9.95
Difference	RU	30	-11	17	$ (1.23)	$ 9.19	$ 2.18
	RD	15	6	12	$ 0.94	$ 8.98	$ 3.51
	SP	113	-9	72	$ (1.14)	$ (0.43)	$ (0.69)
	NS	115	-5	75	$ 1.43	$ (0.10)	$ 1.07
	Total	273	-19	176	$ (0.08)	$ 3.01	$ 0.89

Ancillary Service Market Supply. Market supply was characterized by a substantial increase in the frequency of bid insufficiency. Bid insufficiency in RD nearly tripled to 42 hours (5.8 percent of hours). Many of these instances of bid insufficiency were during off-peak periods.

Bid insufficiency increased by 118 percent from May to June. This increase was driven in part by increasing demand for all products. However, declining off-peak supply in RU and RD contributed to the increase as well. Overall, bid insufficiency in the regulation markets accounted for 83 percent of the bid insufficiency in June. Hydro resources provide a large portion of the regulation capacity procured by the CAISO. When hydro resources shut down overnight, they are not able to provide regulation. This situation was a primary cause of the difference between on-peak and off-peak bid sufficiency. Figure 15 plots the frequency of bid insufficiency.

Figure 14. Frequency of Bid Insufficiency, May – June 2004



IV. Inter-zonal Congestion

- ***Congestion Costs on COI and NOB Surged in June***
- ***Hour-ahead Congestion Price Spikes on June 14 on Several Major Paths***

Inter-zonal congestion costs reached their highest level since 2002, totaling $6.1 million in June 2004. Among all congested paths, the California-Oregon Intertie (COI) and the Pacific DC Intertie (also referred to as the North-of-Oregon Border Intertie, or NOB) accounted for most of the congestion costs, $2.9 million and $2.0 million, respectively. Other paths with significant positive congestion costs included Palo Verde, in the import direction, and Path 26.

COI was congested in 44 percent of hours in June, with an average day-ahead congestion price of $8/MWh. Most of the congestion was attributed to deratings associated with scheduled maintenance (e.g., the outages of Round Mountain and Table Mountain #2-500 kV lines, Malin-Round Mountain #2-500 kV line) and problems with a series capacitor bank on the Mountain-Tesla 500 kV line. Consequently, in June, the importing capacity of COI fluctuated from between 3,000 MW and 4,330 MW. Demand in California for energy from the Pacific Northwest also contributed to the high frequency of congestion on COI.

With the exception of a twelve-hour scheduled outage from 4:00 a.m. to 4:00 p.m. on June 27 (due to clearance of Celilo-Sylmar Poles 3 and 4), the import capacity of NOB was approximately 1,148

MW in June. Similar to COI, NOB incurred significant congestion during the peak hours throughout the month. The average congestion price was $6/MWh while the maximum was nearly $30/MWh.

Congestion also occurred on Palo Verde in the import direction, which was derated by about 1,000 MW during peak hours between June 15 and June 19, due to the clearance of the Imperial Valley-Miguel Line. Overall, congestion prices were much lower in June than in May. The average June congestion price was about $4/MWh, with the maximum congestion price below $25/MWh in the day-ahead market.

Path 26 displayed some unusual congestion patterns in June, incurring congestion in both the north-south and south-north directions. For instance, on June 1 between 6:00 and 7:00 a.m., the path was congested in the south-north direction with a congestion price of $81.64/MWh, while on June 26, between 7:00 and 9:00 p.m., the congestion prices ranged from $37/MWh to $98/MWh in the north-south direction due to line deratings. For most of the month, south-north capacity was limited to 2,550 MW, while north-south capacity was increased from 2,500 MW in the first half of the month to 3,400 MW in the second half of the month. Also, at 4 p.m. on June 14, the hour-ahead congestion price spiked to $245/MWh as a result of a system disturbance in Arizona.

On June 14, between 2:00 and 3:00 p.m., significant price spikes occurred on several major branch groups in the hour-ahead market: NOB ($293/MWh), Mead ($145/MWh), Palo Verde ($391/MWh), and Path26 ($246/MWh). These price spikes were related to the aforementioned concurrent outages in Arizona (i.e., tripping of transmission lines, three Palo Verde nuclear units and two gas-fired Redhawk units) and the uncertainty of the exact time that transmission lines would be fully recovered. At HE1500, the hour-ahead operating transfer capability (OTC) of Palo Verde in the import direction was derated from 2,823 MW to 1,063 MW, causing price spikes in the hour-ahead market.[6]

Table 5 shows the congestion frequency and prices on the major branch groups. Table 6 shows the congestion costs by path.

[6] Grid users that schedule in the day-ahead markets result in congestion when the line is derated between the day ahead and the hour ahead, and submit adjustment bids to indicate their willingness to pay for throughput during periods of congestion. Other grid users that schedule in the opposite direction in the hour-ahead markets relieve the congestion during periods of congestion, and collect those payments based upon day-ahead schedulers' adjustment bids. The Department of Market Analysis calculates total hour-ahead congestion costs as the excess charges beyond such transfer payments. These congestion costs are paid to FTR holders and/or transmission owners.

Table 5. Inter-zonal Congestion Frequencies and Prices in June

	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	0	0	$108		0	0		
CASCADE	29	0	$0		21	0	$0	
COI	44	0	$8		31	0	$14	
ELDORADO	0	0			0	0	$32	
LUGOTMONA	2	0	$6		0	0		
MEAD	3	0	$2		2	0	$19	
NOB	37	0	$6		25	0	$11	
PALOVRDE	14	0	$4		5	0	$25	
PATH15	11	0	$0		4	0	$16	
PATH26	1	1	$12	$15	1	1	$39	$70
SUMMIT	18	1	$2	$38	9	1	$4	$2

Table 6. Inter-zonal Congestion Costs in June

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	$39,716	$0	$0	$0	$39,716	$0	$39,716	$0	$39,716
COI	$2,821,704	$0	$28,847	$0	$2,850,550	$0	$2,821,704	$28,847	$2,850,550
ELDORADO	$0	$0	$15,137	$0	$15,137	$0	$0	$15,137	$15,137
ELVTHRLY	$0	$0	$0	$18	$0	$18	$0	$18	$18
LUGOTMONA	$15,363	$0	$0	$0	$15,363	$0	$15,363	$0	$15,363
MEAD	$41,070	$0	$42,459	$0	$83,529	$0	$41,070	$42,459	$83,529
NOB	$1,983,407	$0	$6,683	$0	$1,990,090	$0	$1,983,407	$6,683	$1,990,090
PALOVRDE	$673,197	$0	-$14,986	$0	$658,211	$0	$673,197	-$14,986	$658,211
PATH15	$0	$0	$49,429	$0	$49,429	$0	$0	$49,429	$49,429
PATH26	$85,699	$181,971	$6,670	$108,142	$92,370	$290,113	$267,670	$114,812	$382,482
SUMMIT	$21,847	$11,257	-$186	$0	$21,661	$11,257	$33,104	-$186	$32,918
Total	$5,682,004	$193,228	$134,053	$108,160	$5,816,056	$301,388	$5,875,232	$242,212	$6,117,444

V. Firm Transmission Rights Market

FTR scheduling. FTRs can be used to hedge against high congestion prices and establish scheduling priority in the day-ahead market. As shown in Tables 7 and 8, a high percentage of FTRs was scheduled on some paths (100 percent on El Dorado, 77 percent on IID-SCE, 96 percent on LUGO-IPP (DC), 66 percent on LUGO-MONA, 40 percent on Palo Verde, 100 percent on Silver Peak in the import direction, and 38 percent on Path 26). FTRs on those paths are mainly owned by Southern California Edison Company (SCE1) and certain municipal utilities.

Table 7. FTR Scheduling Statistics for June, 2004*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE	168	56	167	167	34%
IMP	ELDORADO	536	534	536	536	100%
IMP	IID-SCE	600	460	468	448	77%
IMP	LUGOIPPDC **	370	357	370	235	96%
IMP	LUGOMKTPC **	247	0	8	8	0%
IMP	LUGOTMONA **	160	105	117	65	66%
IMP	LUGOWSTWG **	93	29	44	28	31%
IMP	MEAD	624	14	54	27	2%
IMP	NOB	725	135	198	100	19%
IMP	PALOVRDE	1021	407	688	613	40%
IMP	SILVERPK	10	10	10	10	100%
EXP	LUGOMKTPC	247	3	3	3	1%
EXP	LUGOTMONA	543	3	50	50	1%
EXP	NOB	722	6	23	23	1%
N->S	PATH26	1141	435	945	575	38%

*only those paths on which 1 percent or more of FTRs were attached are listed.
** The FTRs on these paths were awarded to municipal utilities that converted their lines to CAISO operation and were not released in the primary auction.

FTR Revenue per Megawatt. Table 8 summarizes the FTR revenue for the first two months of this FTR cycle. Due to high congestion frequency and high congestion price on COI, NOB and Palo Verde, the FTR revenues on these Paths were significant: $4,853/MWh, $19,123/MWh, and $2,457/MWh, respectively. The FTR revenues on other paths were modest.

Table 8. FTR Revenue Per MW ($/MW), June 2004

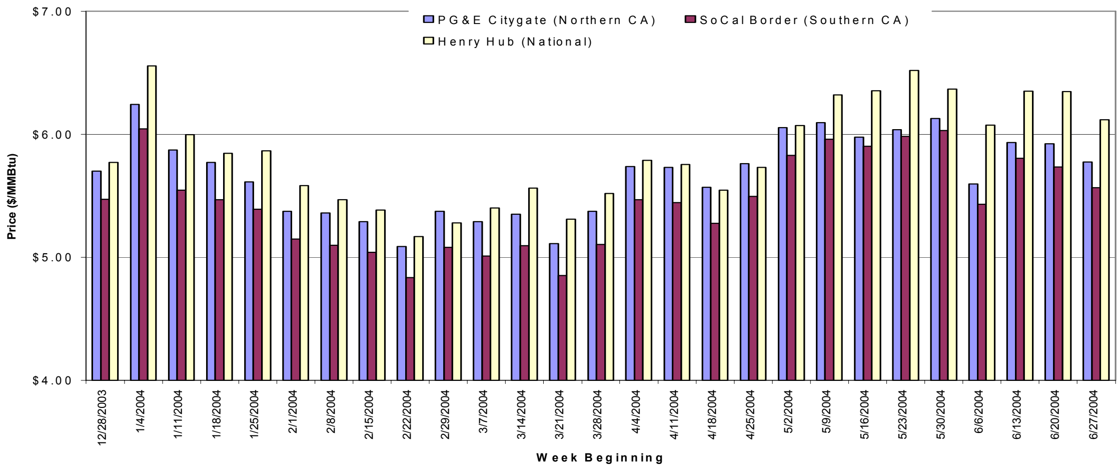
Direction	Branch Group	Net $/MW FTR Rev			Cum Net $/MW FTRREV	Pro Rated NET $/MW FTRREV	FTR Auction Price
		Apr	May	Jun			
IMPORT	BLYTHE	2,791	5,540	433	8,763	35,051	8,759
IMPORT	COI	199	1,481	4,853	6,533	26,133	26,964
IMPORT	ELDORADO	0	408	10	417	1,669	11,646
IMPORT	LUGOIPPDC*	3	0	0	3	12	N/A
IMPORT	LUGOTMONA*	0	0	192	192	768	N/A
IMPORT	LUGOWSTWG*	0	1	0	1	2	N/A
IMPORT	MEAD	1,223	1,168	634	3,026	6,052	14,775
IMPORT	NOB	336	1,816	19,123	21,275	42,549	19,050
IMPORT	PALOVRDE	2,074	15,146	2,457	19,677	39,354	24,346
IMPORT	PARKER	115	15	0	130	520	240
S-N	PATH15	0	20	20	40	158	7,035
N-S	PATH26	0	427	27 0	811	3,244	19,113
EXPORT	SUMMIT	0	0	0 0	608	2,432	625

* FTRs on these paths were awarded to municipal utilities that converted their lines to the CAISO, and were not released in the primary auction.

VI. Natural Gas Market

Mild June temperatures helped to reduce natural gas prices from May levels, particularly during the second week of June, when Southern California prices averaged $5.43/MMBtu. Lower prices were only temporary, however, as higher temperatures in conjunction with the sudden loss of the Palo Verde Nuclear Station on June 14 caused prices to increase sharply from $5.83/MMBtu to $6.15/MMBtu on June 17. The return of the Palo Verde nuclear plants and accompanying reduction in gas-fired electricity generation caused prices to return to $5.65/MMBtu on June 18. Cooling demand associated with high temperatures caused a small price increase to $5.95/MMBtu in Southern California, but prices quickly returned to $5.75/MMBtu levels. Average daily gas prices for June were $6.25/MMBtu at Henry Hub, $5.44/MMBtu at Malin, $5.86/MMBtu at PG&E Citygate, and $5.70/MMBtu at Southern California Border. Average bid week prices for July were $5.84, $5.55, and $5.93/MMBtu for Southern California Border, Malin, and PG&E Citygate, respectively, down 8, 6, and 6 percent from June bid week prices. The following chart shows weekly average gas prices at regional delivery points through June.

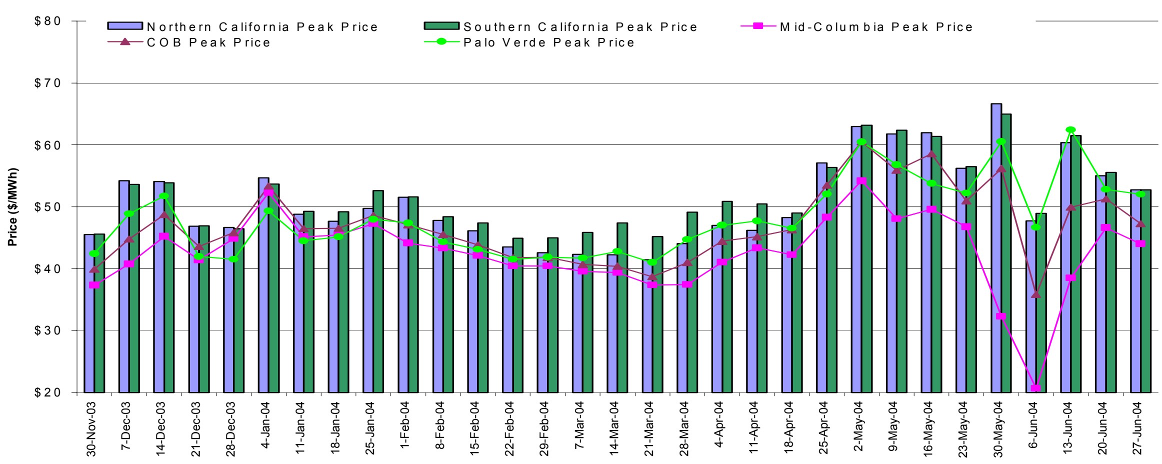
Figure 15. Weekly Average Natural Gas Prices through June



VII. Regional Day-ahead Bilateral Electricity Market

Reduced cooling demand and the accompanying reduction in natural gas prices resulted in lower average electricity prices during June than in May. The loss of Palo Verde units 1, 2, and 3 on June 14 had a dramatic effect on electricity prices at Palo Verde and Southern California. Prices increased from $54.00/MWh to $75.50/MWh at Palo Verde and from $53.25/MWh to $70.50/MWh in Southern California. After the Palo Verde Generating Station returned to service on June 17, higher temperatures helped to keep Southern California prices in the $53 to $55/MWh range. Average June peak weekday regional day-ahead electricity prices were $47.95/MWh at the California-Oregon Border, $35.73/MWh at Mid-Columbia, $55.04/MWh at Palo Verde, $56.60/MWh in Northern California, and $56.93/MWh in Southern California. Figure 16 shows weekly average day-ahead prices for bilaterally-contracted energy at regional trading hubs through June.

Figure 16. Weekly Average Day-Ahead Bilateral Electricity Prices through June



VIII. Issues Under Review

SSG-WI West-wide Market Monitoring Initiative. The Seams Steering Group for the Western Interconnection (SSG-WI) was established as a cooperative effort between the CAISO and those parties forming RTO West and WestConnect to address seams issues between the regions. One of the main efforts of SSG-WI has been to establish a West-wide market monitoring entity (MME) that would monitor the bilateral energy and transmission markets throughout the Western Interconnection. A proposal and workplan for the MME was developed by the Market Monitoring Workgroup (MMWG), a subgroup of SSG-WI, and presented to the SSG-WI Steering Committee for consideration on July 9th. The Steering Committee directed the MMWG to hold regional workshops to educate market participants on the MME proposal. The proposal calls for a voluntary organization where transmission customers would agree to take service through a contract or tariff, and contractually agree to provide necessary and relevant data to the MME. Due to the voluntary nature of the proposal, it is critical that potential participants are clearly informed of the proposed monitoring activities and data requirements of the MME so that they can state whether they intend to participate in the MME. In order for the MME to be effective, a significant number of Western market participants must be willing to fund and provide the necessary bilateral and other data to the MME, otherwise it will be difficult for the MME to effectively monitor the informal power markets currently in place outside of California prior to the establishment of more formalized markets.