CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: September 19, 2003

Re: **Market Analysis Report for July and August 2003**

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

Executive Summary

In July, the ISO Control Area saw near-record loads and in August, had record loads within SP15. Even with those high loads, real-time prices remained moderate. Mark-up of prices in excess of competitive baselines have remained within 10 percent for the past three months. SP15 however, had occasional price spikes due to the combination of high zonal loads and interzonal congestion. Real-time prices for incremental balancing energy averaged $63.66 and $54.27 per megawatt-hour (MWh) in July and August, respectively. Decremental balancing energy prices averaged $26.99 and $20.46/MWh.respectively.

New generation from northern Mexico connected to the ISO Grid in June 2003 has resulted in unprecedented levels of intrazonal congestion within SP15 due to insufficient transmission facilities in the area. There was also significant intrazonal congestion from the Vincent substation continued derate due to a fire on March 21, 2003. Although the Federal Energy Regulatory Commission (FERC) approved Amendment 50 to the ISO Open Access Transmission Tariff on July 1, 2003, instituting some mitigation for out-of-sequence decremental real-time energy dispatches, intrazonal congestion in the region remains a significant problem.

The ISO's Ancillary Service markets were stable with some high prices during high load conditions due to insufficient bidding and high market concentration. Several price spikes occurred in July and August in the spinning and non-spinning reserve markets during high load hours as suppliers with high market concentrations bid high prices into these markets.

The approval by FERC of Amendment 52 to the ISO Tariff on June 25, 2003, repealed the requirement that importers to bid energy into the ISO real-time market only at a price of $0/MWh. Since the repeal, import bids have increased from an average of approximately 600 megawatts (MW) to approximately 1300 MW.

I. Market Trends

Loads and Schedules. Loads were typically high in the peak months of July and August, especially so in SP15. Monthly control area peak loads were 42,581 MW (July 21, HE 16:00) and 42,506 MW (August 25, HE 16:00), just shy of the all-time peak (excluding SMUD) of 42,848 MW, set on July 12, 1999. Loads averaged 30,951 MW in July and 30,600 MW in August, respectively up 4.3 and 5.4 percent from the same months in 2002. The charts below show ISO total hourly actual loads for July and August, compared to the same months in 2002. The table that follows compares monthly peak and average loads for July and August in 2002 and 2003.

Figure 1a. Actual Load in the ISO Control Area for July: 2003 v. 2002[1]

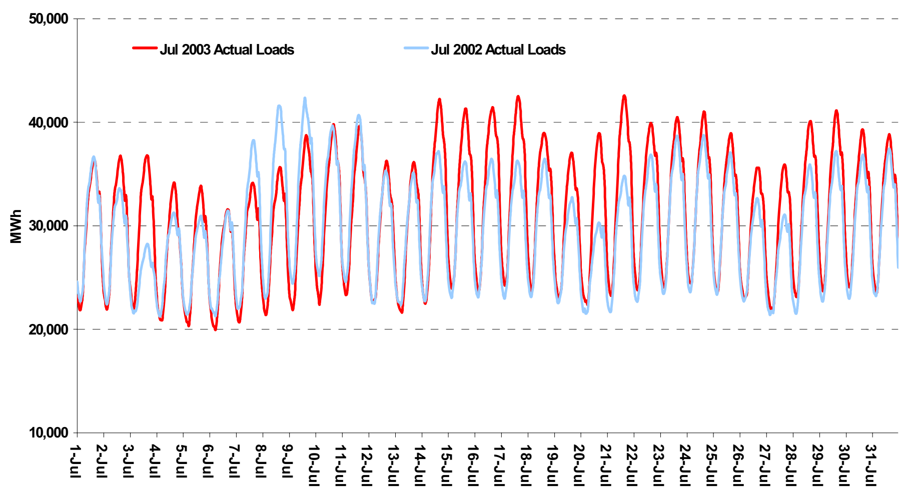
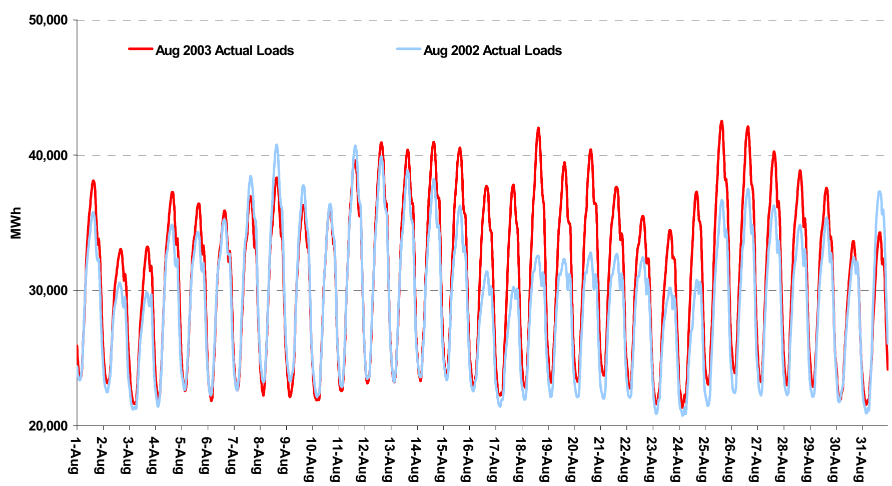


Figure 1b. Actual Load in the ISO Control Area for August: 2003 v. 2002



[1] The ISO changed the method by which it calculates actual load on July 11, 2003. Previously, the ISO recorded instantaneous loads every top-of-hour. The ISO now calculates load using an average of load snapshots every four seconds. This may result in peaks and averages differing slightly from those calculated using the old methodology.

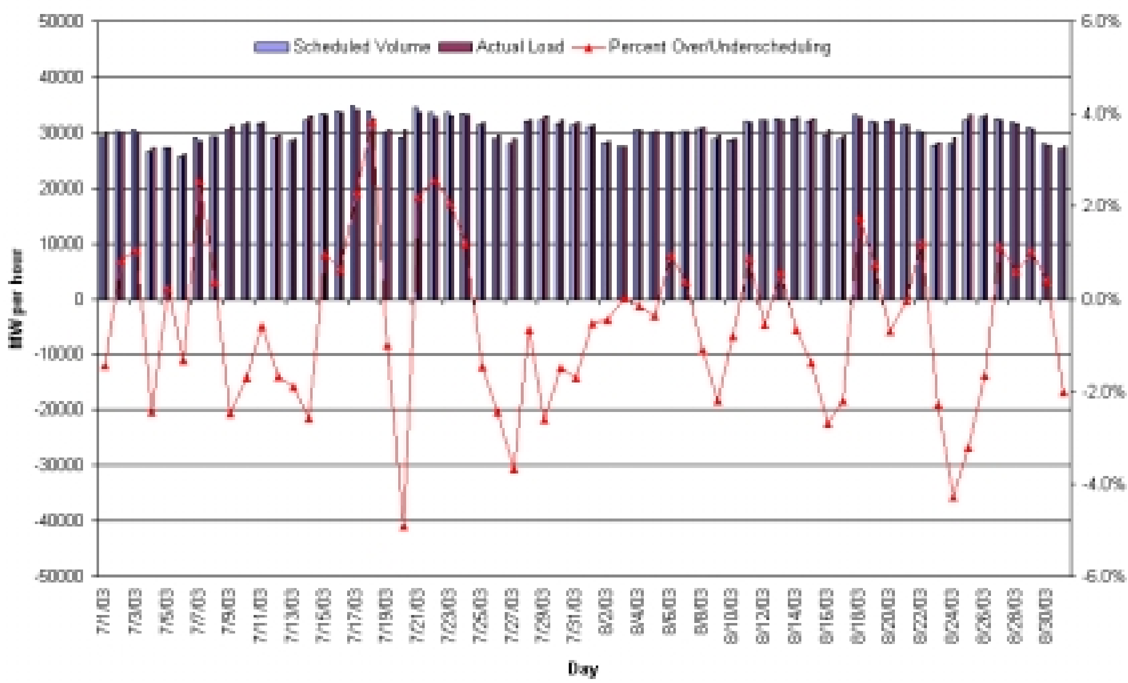
Table 1. Peak Loads and Average Energy for July and August, 2002 v. 2003

	Jul-02	Jul-03	Pct. Chg.	Aug-02	Aug-03	Pct.Chg
Peak Load (MW)	42352	42581	0.5%	40771	42506	4.3%
Avg. Energy (MW)	29676	30951	4.3%	29046	30600	5.4%

Three consecutive record load levels occurred in SP15 beginning on August 12, 2003. A new all-time peak load for SP15 of 24,051 MW was set on August 14, HE 16:00.

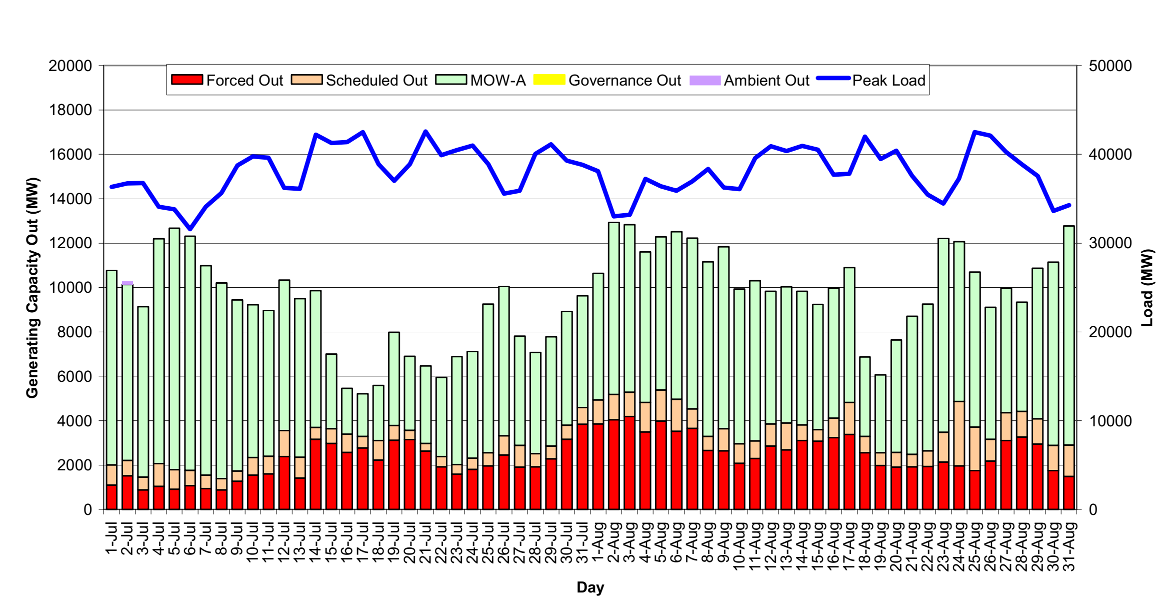
Although loads were high, forward schedules were sufficient particularly during the heat wave in mid-July when the ISO was actually able to decrement generation in real time on several peak days. This was due in part to the significant amount of power procured through long-term contracts by the State of California in early 2002. Because a large portion of that power was contracted for peak-hour blocks (Mondays through Saturdays, 6:00 a.m. to 10:00 p.m.), the ISO was underscheduled on Sunday, July 20, a day in which it experienced its all-time peak load for a Sunday of 38,902 MW. This resulted in high real-time incremental prices and volumes. The following chart shows loads, schedules, and scheduling deviations by day in July and August.

Figure 2. Loads, Schedules, and Scheduling Deviations in July and August



Outages. As is typical, planned outages and approved applications for waivers of the Must-Offer Requirement declined during high load periods, and increased during light load periods. The following chart shows average capacity out of service in July and August.

Figure 3. Daily Average Outages in July and August[2]



II. Real-Time Imbalance Market

Real-time market prices were moderate in July and August, due in part to strong forward scheduling when loads were anticipated to be high. This resulted in low imbalance energy volumes. Incremental (INC) electricity prices, which load-serving entities (LSEs) pay to suppliers to increase output whenever forward schedules are not sufficient to meet load, averaged $63.66 and $54.27/MWh in July and August, respectively, compared to $61.77/MWh in June. The relatively small change between June and July is notable considering the dramatic increase in loads and real-time volume between those two months. Decremental (DEC) electricity prices, which suppliers pay to LSEs for the right to decrease output when forward schedules exceed actual load, averaged $26.99 and $20.46/MWh in July and August, respectively, compared to $13.99/MWh in June. All else equal, lower INC prices and higher DEC prices result in lower overall costs to load. The tables below show monthly average prices and total real-time dispatched energy, and average loads and underscheduling, for July and August. The chart that follows shows monthly average real-time prices and volumes through August.

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[2] "MOW-A" denotes units with approved waivers to the Must-Offer requirement.

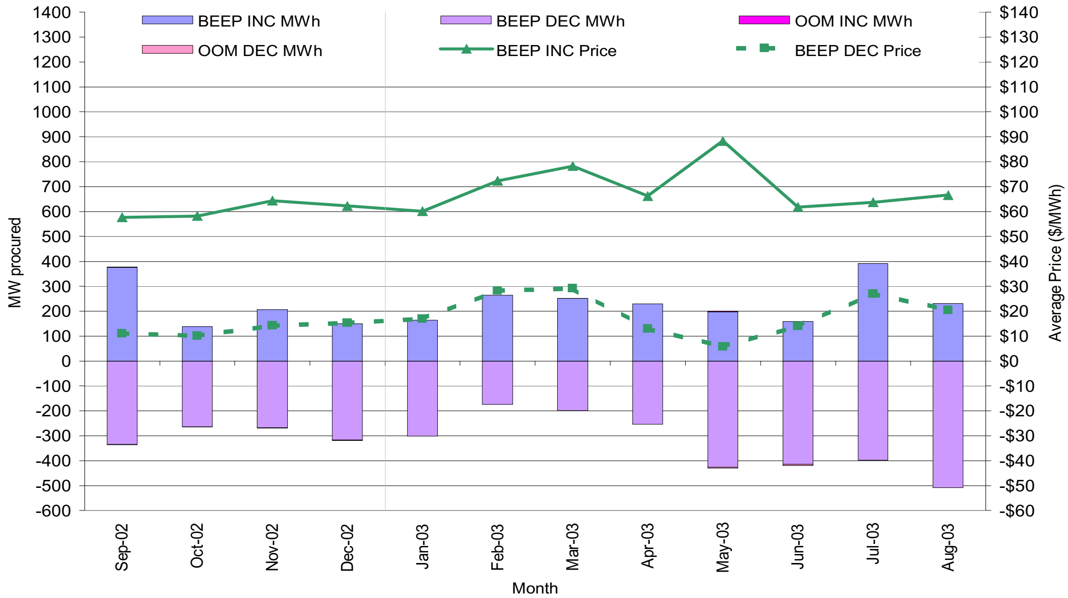
Table 2a. Average Prices, Total Instructed Energy, and Average Loads and Underscheduling for July 2003

	Overall Avg. Real-Time Price and Total Instructed Energy		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$ 66.66	$ 28.12	33,974 MW
	186 GWh	257 GWh	-0.3%
Off-Peak	$ 56.28	$ 19.22	24,903 MW
	76 GWh	37 GWh	2.5%
All Hours	$ 63.66	$ 26.99	30,951 MW
	261 GWh	294 GWh	0.4%

Table 2b. Average Prices, Total Instructed Energy, and Average Loads and Underscheduling for August 2003

	Overall Avg. Real-Time Price and Total Instructed Energy		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$69.67	$21.69	33,643 MW
	137 GWh	285 GWh	0.7%
Off-Peak	$54.27	$16.67	24,515 MW
	34 GWh	92 GWh	0.0%
All Hours	$66.58	$20.46	30,600 MW
	172 GWh	378 GWh	0.5%

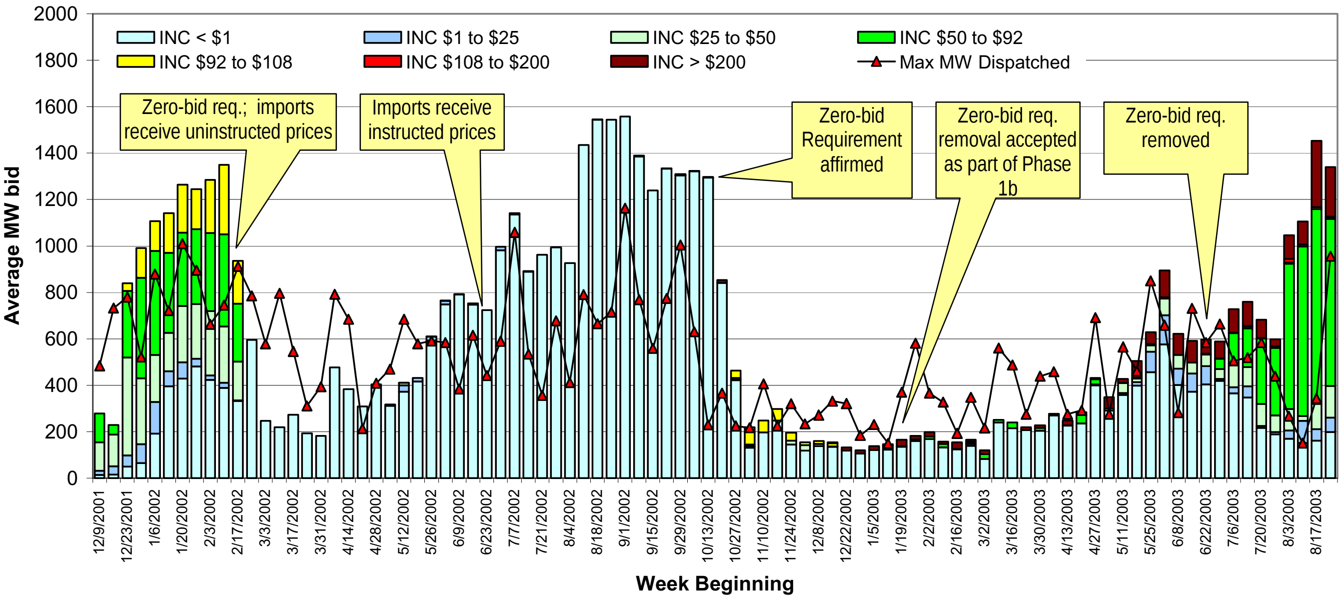
Figure 4. Volume-Weighted Monthly Average Prices and Monthly Average Volumes of Real-Time Instructed Energy through August 2003



Improved Import Bids in the ISO Real Time Market. On December 19, 2001, as part of its market power mitigation measures, the Federal Energy Regulatory Commission directed that bids from imports, or *system resources,* into the real-time market would automatically be set to a price of $0/MWh, effective February 19, 2002. Shortly thereafter, the Commission clarified its Order directing the ISO to pay pre-dispatched bids awarded for a full hour of operation the uninstructed price in those intervals when the ISO had undispatched resources. These, combined with the requirement that system resources receive uninstructed prices in real-time, resulted in a dramatic decrease in average import bid volume from approximately 1300 MW in early February 2002 to approximately 200 MW one month later. On June 11, 2002, the Commission accepted ISO Tariff Amendment 43, which permits system resources to receive the instructed price when pre-dispatched for a full hour of operation. This encouraged importers to increase their bid volumes to the California real-time market and returned real-time import bid volumes by midsummer near to those seen in early 2002. However, as import resources became scarce and opportunity costs increased in the fall of 2002, import bids decreased to approximately 150 MW on average by late 2002. On July 17, 2002, the Commission issued its Order on MD02 Phase 1, leaving the status of the zero-bid requirement in some doubt. The Commission clarified in its Order of October 11, 2002, that the zero-bid requirement remain in effect, and then directed in its Order of January 17, 2003, that the zero-bid requirement be removed upon implementation of Phase 1b of MD02. Since Phase 1b has since been delayed, the Commission accepted ISO Tariff Amendment 52 on June 24, repealing the zero-bid requirement and the ISO implemented its direction on June 25. Since that time, resources bid to the real-time market have increased, generally at prices significantly above $0/MWh.

The following chart shows incremental bids from resources outside of the ISO control area into the real-time market since December 2001.

Figure 5. History of Bid Volume by Imports in Real-time Market Weekly Averages, Dec-01 through Aug-03



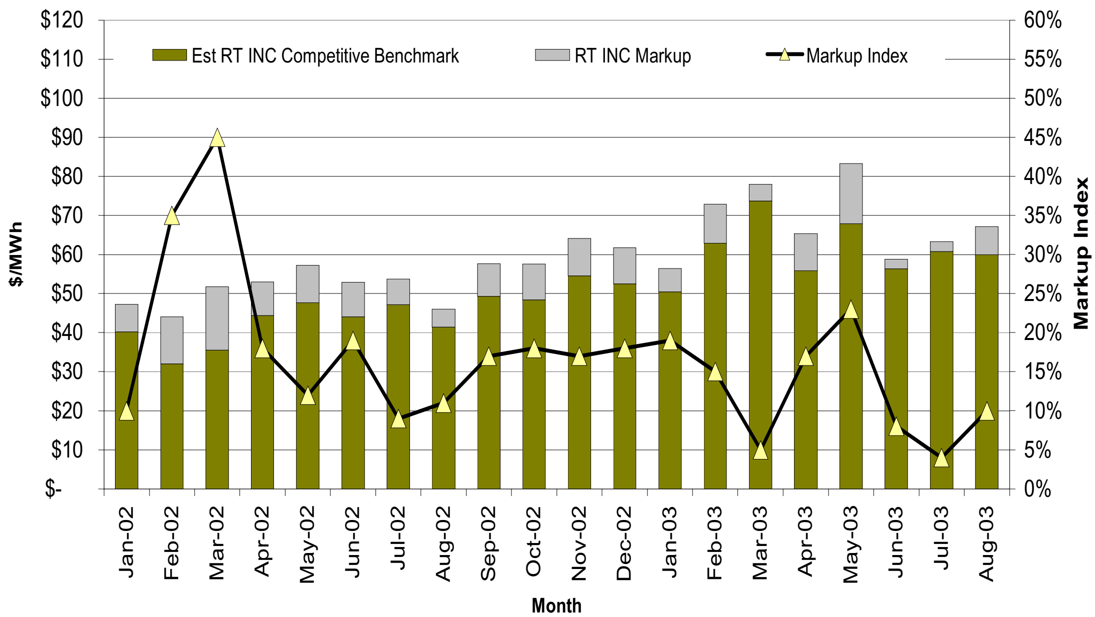
Price-to-Cost Markup as a Measure of Market Power. Market power is the ability of one or more sellers to sustain prices above levels that would emerge in a competitive environment; or the ability of one or more buyers to sustain prices below such levels. One measure of sellers' market power in the California wholesale electricity markets is the price-to-cost markup, the difference between the actual price paid in the market for wholesale electricity and an estimate of the production cost of the most expensive, or marginal, unit of electricity needed to serve load. The ratio of the volume-weighted average markup to marginal cost is a metric that can be used to identify market power trends over time. The ISO previously has published a markup index that incorporates "short-term energy" transactions, or those for day-ahead, hour-ahead, and real-time energy. Since investor-owned utilities (IOUs) resumed procurement of short-term forward energy from the State Department of Water Resources' California Energy Resources Scheduling Division (CERS) in January 2003, day-ahead and hour-ahead purchase information has not been available to the ISO.

Given the lack of short-term forward purchase data from the California IOUs, DMA has developed a temporary index designed to measure market power in the real-time market. This index compares real-time market prices to estimates of real-time system marginal costs. It excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[3] This index is an extremely conservative measure of the magnitude of market inefficiencies: It does not account for the withholding of low-cost units from the market either by the owner bidding excess of the unit's variable cost or by the owner simply refusing to offer the unit to the market at any price.

[3] The original price-cost markup index used system marginal cost based on all resources available for day-ahead scheduling. That competitive bench-mark is more applicable to measure competitiveness of day-ahead and short-term energy market. Only a subset of those resources is used in the calculation of the real-time mark-up.

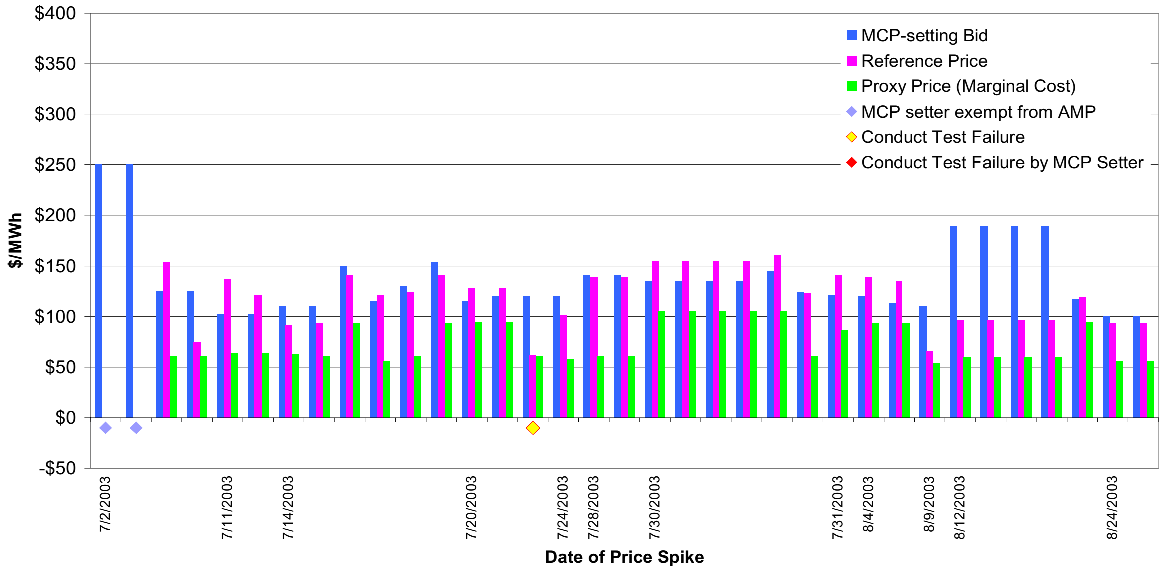
While an index based upon the relatively thin real-time market is not the preferred method of calculating markup, it serves as a temporary substitute in the interest of providing a profile of general market trends. The following chart shows the new real-time markup index between January 2002 and August 2003, and indicates that real-time market prices have included markups below 25 percent over the past year. It also suggests that the market for real-time incremental energy has become increasingly competitive in the last few months, with markup within 10 percent of cost in the summer months of 2003.

Figure 6. Temporary Index of Real-Time Markup: Resources Responsive to Real-Time Dispatch Instructions January 2002 through August 2003



Automatic Mitigation Procedure (AMP) Performance and Price Spikes. Since its implementation on October 30, 2002 through August, no unit has failed the AMP Impact Test. Thus, there has not yet been AMP price mitigation. Units failed the AMP Conduct Test in only two hours between July 1 and August 31. On July 20, HE 16:00, the AMP was applied in an hour with a price spike. A single thermal qualifying facility unit that fails the Conduct Test whenever AMP is applied did so. This price spike is discussed in the next section. On August 9, HE 14:00, several units that often set the price failed the Conduct Test. However, the actual incremental dispatch prices in this hour ranged between $39.72 and $68.53/MWh, so mitigation was not necessary. The following chart shows real-time market clearing prices of at least $100/MWh in July and August, and the reference level and estimated marginal cost of the price-setting units during the same intervals. It also includes indicators of whether the price-setting unit was exempt from AMP (as would, for example, a load group or a hydroelectric unit); and whether the price-setter or another unit failed the Conduct Test in the hour of the spike.

Figure 7. Interval Market-Clearing Prices of $100/MWh or greater in July and August, with Reference Levels and Estimated Marginal Costs of Price Setters, and Conduct Test Failures



Review of Price Spikes for July-August On July 2, a fire near the Tesla-Los Ba os line required a derating of Path 15 to 1,281 MW in the South-to-North direction, as well as deratings of Path 26 to 550 MW in the South-to-North direction and the California-Oregon Intertie (COI) to 1,300 MW in the North-to-South direction. These deratings constrained transmission into NP15, causing the zonal INC price to reach $250/MWh between 6:50 and 7:30 p.m., and then to recede to $125/MWh until 7:50 p.m. The $250/MWh price was set by a supplier not subject to AMP; the $125/MWh price was set by two different peaking units in different intervals that set prices frequently and had reference levels at that hour of $154 and $74/MWh, respectively. Due to the sudden nature of the spike and rapid recovery from it, the predicted price (for the purposes of the AMP price screen) during the spike was below $91.87/MWh, so AMP was not applied in the hours that the spike occurred. The spike had a market impact of approximately $170,000.

On July 14, a large coal unit in another control area and a small hydroelectric unit in California both tripped, causing a frequency disturbance. This caused a moderate real-time price spike between 3:00 and 4:40 p.m. The price ranged between $115 and $130/MWh for 30 minutes. The price then increased to the range of $149 to $154/MWh for the remaining 70 minutes, set by a unit whose reference level was approximately $141/MWh and whose estimated marginal cost was approximately $93/MWh. The units that set prices during the spike were all peaking facilities. Since the predicted price was below $91.87/MWh, AMP was not applied.

On July 20, the price spiked to the range of $116 to $120/MWh from 2:00 to 3:40 p.m., as the ISO experienced its all-time record peak load for a Sunday, of 38,902 MW (HE 17:00).[4] Under-scheduling exceeded eight percent of load, with forward schedules based on early forecast were

[4] This total excludes load for the Sacramento Municipal Utilities District (SMUD), which withdrew from the ISO in 2002.

significantly less than actual loads. The ISO balanced generation with load by procuring in excess of 2000 MW of real-time energy between HE 13:00 and HE 19:00, with a maximum dispatch of 3,408 MW in HE 15:00, interval 6. A single non-price setting thermal unit failed the Conduct Test in HE 16:00. The price setters were two other peaking units, one with a reference level of approximately $127/MWh and marginal cost of approximately $94/MWh, and the other with both a reference level and cost of approximately $61/MWh. This second price-setting unit bid just below its Conduct Test threshold, which was equal to twice its reference level. The market impact of this spike was approximately $224,000.

On August 12, SP15 zonal load reached 23,994 MW in HE 16:00 (an all-time zonal load record at that time, to be reset on August 14 at 24,051 MW). Transmission congestion on Path 26 in the North-to-South direction caused a split in real-time prices. The SP15 price was constant at $189/MWh between 1:30 and 4:50 p.m. This price was set by a gas-fired combustion turbine dispatched for 0.3 MW, whose reference level was $96.46/MWh, and whose estimated marginal cost was $58/MWh. This unit, which was nearly fully forward-scheduled, had begun bidding the small remainder of its capacity into the real-time market at a price of $189/MWh on August 11. It ceased doing so within one hour of the ISO contacting its scheduling coordinator for an explanation following this spike. While the unit itself was dispatched for relatively little volume since it was nearly fully forward-scheduled, its scheduling coordinator had been awarded between 175 and 200 MW of incremental energy within SP15 during the spike. Total incremental dispatch within SP15 peaked in HE 15:00 interval 6 at approximately 2,144 MW. During this spike, approximately 18 MWh were also procured "as bid" at $350/MWh from an emissions-constrained resource scheduled by another entity.[5] The predicted price was below $91.87/MWh for the entire duration of the spike, so AMP was not applied. The total market impact of the spike was approximately $800,000.

Intrazonal (Within zone) congestion. There was a total of 189,732 MWh of incremental energy called out of sequence (OOS) in July and August. The average price paid was $58/MWh, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $5.2 million[6]. This represents a substantial increase over previous months. In June the re-dispatch premium over the MCP was approximately $53,000. There were a number of reasons for this increase in intrazonal congestion:

- Vincent Transformer Banks: Due to the fire in late March 2002, only two of the three Vincent 500/230 kV transformers currently are in service. When the third bank enters service (expected by mid-September), the Vincent transformer bank congestion should be resolved. Lack of loaded generation in the L.A. area, and the higher flows on Path 26 contribute to the congestion on the Vincent transformer banks.
- South of Lugo Flows: A lack of loaded generation in the Los Angeles Basin area results in greater flows into the area, which increases flows South of Lugo, resulting in congestion.
- Five 115kV lines have also been intermittently down for maintenance, as has a 500kV line.

On the decremental side, a total of 122,142 MWh of energy was dispatched out of sequence. On July 1, new mitigation measures, approved by the FERC in Amendment 50 to the ISO Tariff, went into effect. Subsequent to July 1, 2003, decremental dispatches are settled at the lower of the

[5] Since this volume was bid above the soft price cap of $250/MWh it was paid as bid, but was not eligible to set the market-clearing price.
[6] Part of the premium reflects the increased cost of redispatch, other part may be mark-up above cost.

zonal decremental price for energy or the decremental reference price for that unit. The dispatch order is also not related to the unit's bid price but rather to the decremental reference price and the effectiveness of the unit in mitigating the congestion. The main reason for this substantial increase in decremental dispatches has been the recently added Mexican generation in the CFE Control Area. Since late July, 83% of all decremental dispatches have been directly related to the Mexican generation problem.

The following table shows volumes, costs, premiums above the market-clearing price, and average costs and redispatch premiums (the price per MWh above the MCP in the dispatched interval) for incremental and decremental OOS energy.

Table 3. Out-of-Sequence Volumes, Costs, and Redispatch Premiums

		MWh	Gross_Cost	Redispatch	Avg_price	Avg. premium
July	INC	11,941	$ 794,015.	$ 268,759.	$ 66.	$ 22.51
August	INC	177,791	10,189,224.	4,936,341.	57.	27.76
July	DEC	-4,803	-88,072.	104,162.	18.	21.69
August	DEC	-117,339	-1,768,946.	3,503,297.	15.	29.80

Locational Market Power Mitigation. AMP allows for the mitigation of OOS dispatches to mitigate instances of locational market power. AMP for local market power mitigation (AMP LMPM) uses only a conduct screen (no impact screen) and a lower threshold. If the bid price is $50/MWh or 200% greater than the MCP, the bid will be mitigated to the higher of MCP or the unit's Reference Price. Since inception, mitigation of incremental OOS dispatches has occurred every month with the exception of February, as indicated in Figure 8 and Table 3 below.

Figure 8 shows the re-dispatch cost in red and the actual cost in yellow (comprising both true marginal cost as well as any remaining mark-up due to local market power). Actual savings are shown in light blue. Lower thresholds in AMP for local market power would result in an increase in the size of the blue region, all other factors equal. Table 3 shows that, since AMP LMPM was instituted at the end of October 2002, there has been a total of approximately $18.8 million in gross OOS costs. The current mitigation structure has provided about $546,025 in cumulative savings through mitigation.

Figure 8. Components of Out-Of-Sequence Costs and Effect of AMP on Local Market Power Mitigation

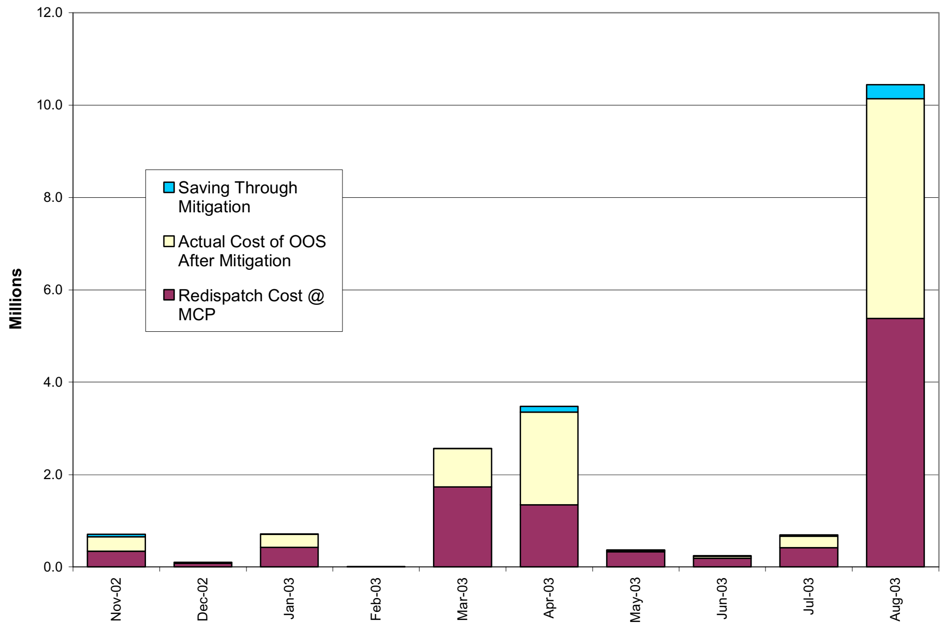


Table 4. Local Market Power Mitigation Impacts Since November 2002

Month	Mwh	Redispatch Cost @ MCP	Actual Cost w/Mitigation	Original Cost w/o Mitigation	Mitigated Dollars (Original Cost - Actual Cost)
Nov-02	9,732	$ 340,442	$ 648,586	$ 707,990	$ 59,404
Dec-02	1,402	78,644	99,017	102,383	3,366
Jan-03	10,234	423,685	708,734	716,168	7,434
Feb-03	163	9,504	12,482	12,482	0
Mar-03	33,872	1,735,419	2,561,223	2,563,396	2,173
Apr-03	54,654	1,344,311	3,353,006	3,475,300	122,294
May-03	5,290	323,426	359,053	368,565	9,512
Jun-03	3,833	184,577	235,459	239,610	4,152
Jul-03	9,950	421,912	668,197	697,024	28,827
Aug-03	176,068	5,377,308	10,132,961	10,441,824	308,863
Totals	305,199	10,239,227	18,778,718	19,324,743	546,025

In the months of July and especially in August, there was a significant amount of local market power mitigation as a number of units were OOS mitigated. Gross OOS costs for July and August were $697,024 and $10,441,824. The mitigation procedure provided about $337,690 of cumulative mitigation for both months, or 6.75% of the difference between the bid price gross cost and the equivalent market clearing price cost.

III. Ancillary Services Markets

Prices for regulation and spinning reserve services have decreased on average during the course of the summer. The price of non-spinning reserves peaked in July and has declined since then. The following table shows average requirements and prices for June, July and August of 2003.

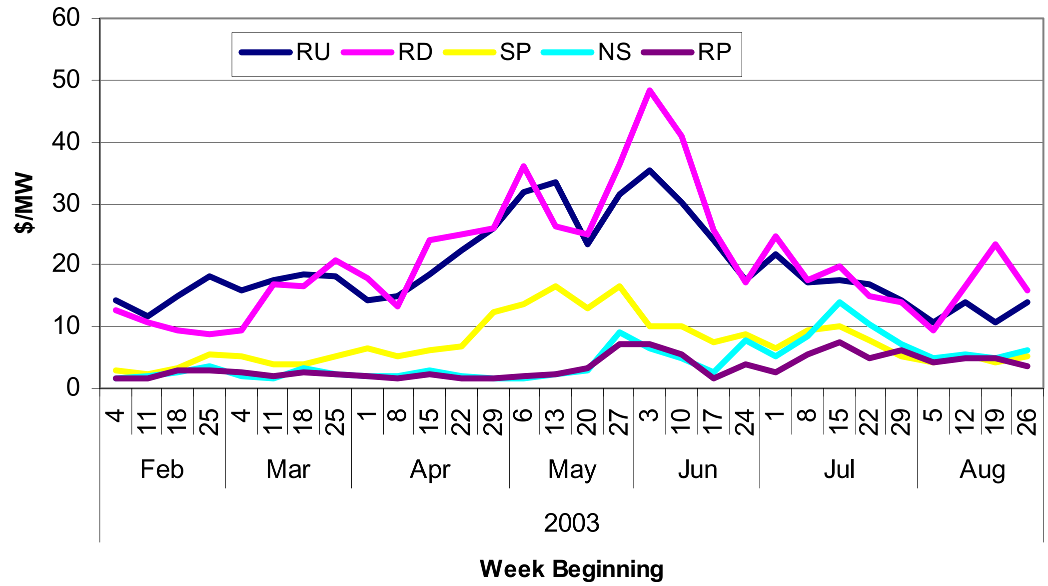
Table 5. Hourly-Average Requirements and Monthly Weighted Average Prices

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Jun 03	377	425	776	699	$ 28.42	$ 34.03	$ 9.91	$ 6.68
Jul 03	427	442	943	874	$ 18.03	$ 18.84	$ 8.29	$ 9.68
Aug 03	400	474	914	818	$ 12.32	$ 16.08	$ 4.76	$ 5.29

The decreases in average price for all products since June were the result of increasing bid sufficiency. Bid sufficiency increased due to the availability of more capacity in the market.

The opening weeks of July and August had similar average prices for non-spinning reserves ($5.35/MW and $4.90/MW, respectively). During the third week of July, the average price was $13.84/MW. During the latter half of July, there were several days of very high load (greater than 41,000 MW during peak hours). During such periods the demand for operating reserves peaked while the capacity available to provide these services was used for energy production. During such periods, market price increases are expected. There were, however, a number of price spikes (greater than $60/MW) in the day-ahead non-spinning reserves market that we cannot explain by a simple increase in demand and decrease in supply. We are currently reviewing these price spikes.

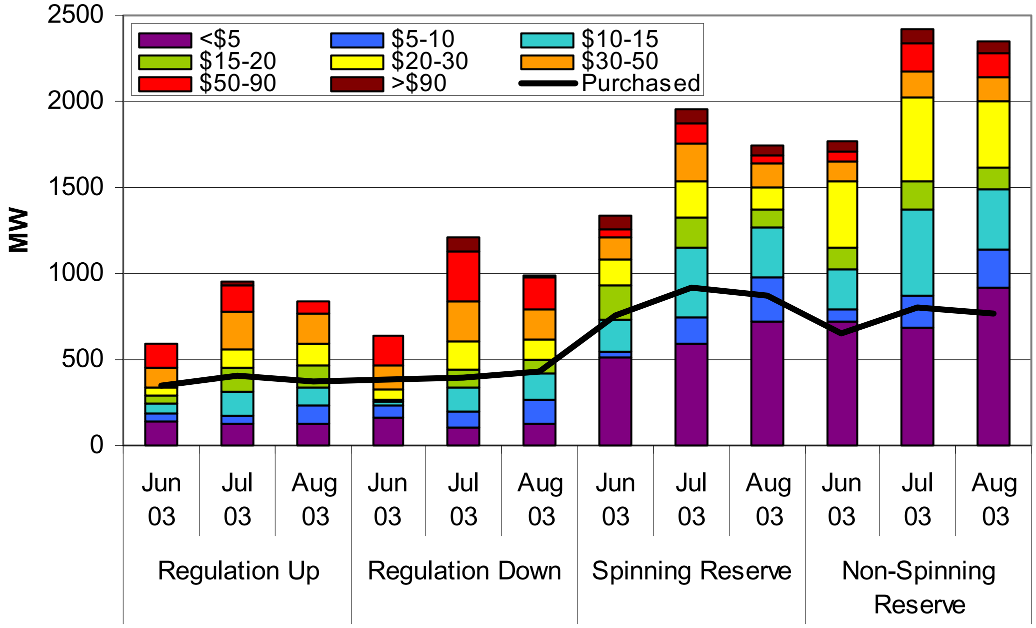
Figure 9. Weekly Average Prices, February - August 2003



Regulation-down weekly-average market prices peaked in the third week of August at $23.37/MW. This peak coincided with a peak in average demand for regulation-down. Typically the regulation - down demand profile peaks during the morning and evening ramps. During the middle weeks of August, demand for regulation-down continued a peak levels throughout the on-peak hours. Increased demand together with reduced bid volumes from July to August led to higher prices.

Bid volumes have increased since June in all markets. Bid volumes decreased slightly from July to August, but were still much higher in August than in June. In regulation up and down, the additional volumes were spread throughout the middle to highest price brackets. Since bid insufficiency was the major contributor to higher prices in May and June, these additional volumes resulted in reduced average prices for these products. In spinning reserves, the lowest and middle price bracket bid volumes grew. This contributed to lower spin prices since bids under $10/MW grew consistently from June to August. In June, the non-spinning reserve markets had adequate bids. Bid volumes increased substantially from June to July, but most of the additional volume was priced above the weighted average price in June. Higher prices were a direct result under increasing demand. From July to August, more bids priced below $5/MW entered the market, which triggered overall decreases in price from July.

Figure 10. Monthly Average Bid Composition



IV. Inter-zonal Congestion

Congestion costs totaled approximately $5 million and $2.4 million in July and August, respectively, a significant increase from the $1 million reported in June.[7] Of the $5 million in inter-zonal congestion costs in July, nearly $2 million were incurred on the Lugo-IPP DC branch group. Path 26 continues to sustain significant congestion in the North to South direction, with congestion costs of $1.6 million and 1.2 million in July and August, respectively. Other congestion costs were incurred on Blythe, COI, NOB, Palo Verde, and Path 15, mostly in the import direction.

All $2 million of congestion costs on the Lugo-IPP DC branch group were incurred on July 1 (from HE7 to HE22) and July 27 (HE7-HE12 and HE21-HE22). While these charges appear unusually high, they are in fact incurred by FTR holders, who themselves receive the payments up to their FTR allocations. In all of these congested hours, the congestion price exceeded $200/MWh. Lugo-IPP DC became an ISO branch group in January 2003, and has an import capacity of 370 MW. When this transmission line was ceded to the ISO, FTRs were distributed to help former owners hedge against possible congestion charges. The congestion price spikes occurred when one municipal utility submitted a schedule that exceeded its FTR entitlement without providing adjustment bids.

As in previous months, Path 26 continued to experience significant congestion in the North-to-South direction in July and August, as load in Southern California purchased hydroelectric energy from the Pacific Northwest and Northern California, congesting transmission toward Southern California. Congestion occurred most frequently in the first half of July, particularly in peak hours,

[7] In Inter-zonal Congestion and Firm Transmission Right Market sections, only data up to August 27 are used in computing all the indexes in tables. This is due to the time schedule for releasing this report.

with day-ahead congestion prices peaking at $20/MWh. In August, Path 26 was congested in 42 percent of all peak hours. In nearly every day in August, Path 26 experienced congestion in some peak hours. In many such hours, day-ahead schedule curtailment exceeded 1,000 MW. In both July and August, Path 26 was available at its current full capacity of 2,500 MW in the North-to-South direction.

The California-Oregon Intertie (COI) and the Pacific DC Intertie (also referred to as the North-of-Oregon-Border Intertie, or NOB) also experienced congestion in July and August. Both COI and NOB were derated moderately for most of July and the first half of August due to scheduled annual maintenance. Another major derating of COI occurred at the end of August. COI was derated on August 26, 27, and 28 to about 2,650 MW, due to the outage of Olinda-Tracy 500kv line to replace damaged spacers. NOB was completely derated on August 2 and 3 for maintenance. Congestion prices were moderate, peaking at $5/MWh on COI and $3.50/MWh on NOB.

Palo Verde was congested day-ahead in the import direction on July 10, 20, and 27, and on August 16, 17, and 26-28. On July 10, HE 3:00 to HE 5:00, the import capacity of Palo Verde was derated to 1,063 MW due to a 500 kV line de-energized for maintenance work. The congestion price at this time spiked to $52.75/MWh. Congestion prices on July 20 and 27 all were $7/MWh. The congestion price was less than $15/MWh in most hours in August, with import capacity fixed at 2,823 MW. The following tables show Inter-zonal congestion frequencies and prices for July and August and total costs for July and August.

Table 6a. Interzonal Congestion Frequencies and Prices, July 2003

			DA			HA		
Branch Group	Direction of Cng.	Peak/Off-Peak Hours	No. of Cngs. Hours	Pct of Hours Being Cng.	Avg Cng. Price ($/MWh)	No. of Cngs. Hours	Pct of Hours Being Cng.	Avg Cng. Price ($/MWh)
BLYTHE _BG	Import	ON-PEAK	9	1%	153.90	4	1%	160.89
COI _BG	Import	ON-PEAK	86	12%	1.62	65	9%	15.39
ELDORADO _BG	Import	OFF-PEAK				1	0%	39.89
LUGOIPPDC_BG	Import	ON-PEAK	24	3%	214.63			
MEAD _BG	Import	OFF-PEAK				1	0%	67.77
MEAD _BG	Import	ON-PEAK				6	1%	35.75
NOB _BG	Import	ON-PEAK	72	10%	1.20	38	5%	15.95
PALOVRDE _BG	Import	OFF-PEAK	4	1%	39.57	4	1%	21.47
PALOVRDE _BG	Import	ON-PEAK	12	2%	7.00	2	0%	5.03
PATH15 _BG	S-N	OFF-PEAK	2	0%	0.00	8	1%	20.26
PATH15 _BG	S-N	ON-PEAK	1	0%	0.00	2	0%	95.36
PATH26 _BG	N->S	ON-PEAK	145	19%	0.01	45	6%	0.00
PATH26 _BG	N->S	OFF-PEAK	1	0%	3.01			
RNCHLAKE _BG	Export	ON-PEAK				1	0%	30.00

Table 6b. Interzonal Congestion Frequencies and Prices, August 2003

			DA			HA		
Branch Group	Direction of Cng.	Peak/Off-Peak Hours	No. of Cngs. Hours	Pct of Hours Being Cng.	Avg Cng. Price ($/MWh)	No. of Cngs. Hours	Pct of Hours Being Cng.	Avg Cng. Price ($/MWh)
BLYTHE	IMPORT	ON-PEAK	3	1%	209.75			
CASCADE	IMPORT	ON-PEAK	12	3%	0.00	1	0%	5.00
COI	IMPORT	ON-PEAK	166	38%	2.11	112	28%	3.64
LUGOIPPDC	IMPORT	ON-PEAK				2	0%	30.00
LUGOTMONA	IMPORT	OFF-PEAK	16	7%	1.00			
MEAD	IMPORT	OFF-PEAK	1	0%	15.01			
MEAD	IMPORT	ON-PEAK				2	0%	55.28
NOB	IMPORT	ON-PEAK	66	15%	0.97	58	11%	16.83
PALOVRDE	IMPORT	OFF-PEAK	2	1%	15.75	1	0%	32.89
PALOVRDE	IMPORT	ON-PEAK	40	9%	4.08	20	5%	17.26
PATH15	S-N	OFF-PEAK	8	4%	0.00	4	2%	36.41
PATH15	S-N	ON-PEAK	6	1%	0.00	7	2%	34.05
CASCADE	EXPORT	ON-PEAK	7	2%	0.00	24	6%	0.00
ELVTHRLY	EXPORT	OFF-PEAK	4	0%	139.50	1	0%	30.00
ELVTHRLY	EXPORT	ON-PEAK	13	0%	249.54	8	0%	77.00
PATH26	N-S	OFF-PEAK	1	0%	7.00	1	0%	3.00
PATH26	N-S	ON-PEAK	182	42%	3.01	88	22%	8.80

Table 7. Inter-zonal Congestion Costs, July 2003

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost
	Import	Export	Import	Export	Export	Import	Day-ahead	Hour-ahead	
BLYTHE _BG	$285,366	$0	$7,771	$0	$293,137	$0	$285,366	$7,771	$293,137
COI _BG	$209,805	$0	-$2,822	$0	$206,984	$0	$209,805	-$2,822	$206,984
ELVTHRLY _BG	$0	$0	$0	$4	$0	$4	$0	$4	$4
LAUGHLIN _BG	$0	$57	$1	$0	$1	$57	$57	$1	$57
LUGOIPPDC_BG	$1,906,062	$0	$0	$0	$1,906,062	$0	$1,906,062	$0	$1,906,062
LUGOWSTWG_BG	$11	$0	$0	$0	$11	$0	$11	$0	$11
MEAD _BG	$0	$0	$99,905	$0	$99,905	$0	$0	$99,905	$99,905
NOB _BG	$147,554	$0	$16,099	$0	$163,653	$0	$147,554	$16,099	$163,653
PALOVRDE _BG	$284,005	$0	$18,264	$0	$302,269	$0	$284,005	$18,264	$302,269
PATH15 _BG	$0	$0	$355,792	$0	$355,792	$0	$0	$355,792	$355,792
PATH26 _BG	$0	$1,587,100	$0	$12,056	$0	$1,599,157	$1,587,100	$12,056	$1,599,157
RNCHLAKE _BG	$0	$0	$0	$6,601	$0	$6,601	$0	$6,601	$6,601
Grand Total	$2,832,803	$1,587,157	$495,009	$18,661	$3,327,813	$1,605,818	$4,419,960	$513,670	$4,933,630

Table 8. Inter-zonal Congestion Costs, August 2003

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost
	Import	Export	Import	Export	Export	Import	Day-ahead	Hour-ahead	
BLYTHE _BG	$62,733	$0	$0	$0	$62,733	$0	$62,733	$0	$62,733
CASCADE _BG	$0	$0	$400	$0	$400	$0	$0	$400	$400
COI _BG	$492,422	$0	$2,033	$0	$494,454	$0	$492,422	$2,033	$494,454
ELVTHRLY _BG	$0	$114	$0	$19	$0	$133	$114	$19	$133
LUGOIPPDC_BG	$0	$0	$2,822	$0	$2,822	$0	$0	$2,822	$2,822
LUGOTMONA_BG	$2,560	$0	$0	$0	$2,560	$0	$2,560	$0	$2,560
MEAD _BG	$10,057	$0	$46,529	$0	$56,586	$0	$10,057	$46,529	$56,586
NOB _BG	$121,852	$0	$96,773	$0	$218,625	$0	$121,852	$96,773	$218,625
PALOVRDE _BG	$412,569	$0	-$4,794	$0	$407,775	$0	$412,569	-$4,794	$407,775
PATH15 _BG	$0	$0	$12,615	$0	$12,615	$0	$0	$12,615	$12,615
PATH26 _BG	$0	$1,164,299	$0	$5,156	$0	$1,169,456	$1,164,299	$5,156	$1,169,456
Grand Total	$1,102,194	$1,164,414	$156,378	$5,175	$1,258,572	$1,169,589	$2,266,607	$161,554	$2,428,161

V. Firm Transmission Rights Market

FTR scheduling. On some paths, FTRs were used to establish scheduling priority in the day-ahead markets. As shown in the following tables, a high percentage of FTRs was scheduled on some paths (in July: 100% on Eldorado, 93% on Lugo-IPP DC, 94% on Palo Verde, 100% on Silver Peak in the import direction, and 57% on Path 26; in August: 100% on Eldorado, 93% on Lugo-IPP DC, 88% on Palo Verde, 100% on Silver Peak in the import direction, and 56% on Path 26). FTRs on those paths are mainly owned by Southern California Edison (SCE1) and municipal utilities. Also, the FTR scheduling on Path 26 was higher during the past several months, compared to earlier months in the year. Apparently, FTR owners used their FTRs to hedge against the possible high congestion prices on this path.

Table 9. FTR Scheduling Statistics for July, 2003*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE _BG	167	59	167	167	35%
IMP	COI _BG	745	318	553	500	43%
IMP	ELDORADO _BG	510	510	510	510	100%
IMP	IID-SCE _BG	600	435	466	446	72%
IMP	LUGOIPPDC_BG**	370	342	364	231	93%
IMP	LUGOMKTPC_BG**	247	1	25	25	1%
IMP	LUGOTMONA_BG**	167	84	100	60	50%
IMP	LUGOWSTWG_BG**	93	24	43	28	26%
IMP	MEAD _BG	516	12	74	38	2%
IMP	NOB _BG	686	135	299	100	20%
IMP	PALOVRDE _BG	627	589	625	600	94%
IMP	SILVERPK _BG	10	10	10	10	100%
EXP	LUGOTMONA_BG**	543	25	126	126	5%
EXP	MEAD _BG	464	57	266	141	12%
EXP	NOB _BG	664	18	83	83	3%
EXP	PALOVRDE _BG	870	10	100	100	1%
EXP	PATH26 _BG	1,425	807	1,365	575	57%

Table 10. FTR Scheduling Statistics for August, 2003*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE _BG	167	78	167	167	47%
IMP	COI _BG	745	337	503	500	45%
IMP	ELDORADO _BG	510	510	510	510	100%
IMP	IID-SCE _BG	600	419	430	410	70%
IMP	LUGOIPPDC_BG**	370	343	361	229	93%
IMP	LUGOMKTPC_BG**	247	1	10	10	0%
IMP	LUGOTMONA_BG**	167	94	100	60	56%
IMP	LUGOWSTWG_BG**	93	25	43	28	27%
IMP	MEAD _BG	516	10	63	50	2%
IMP	NOB _BG	686	78	258	100	11%
IMP	PALOVRDE _BG	627	549	625	600	88%
IMP	SILVERPK _BG	10	10	10	10	100%
EXP	LUGOTMONA_BG**	543	27	60	60	5%
EXP	MEAD _BG	464	20	166	141	4%
EXP	NOB _BG	664	18	83	83	3%
EXP	PALOVRDE _BG	870	1	25	25	0%
N-S	PATH26 _BG	1,425	797	1,365	575	56%

*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 to the ISO operation. They were not released in the primary auction.

FTR Revenue per Megawatt. The following table summarizes the FTR revenue collected in July and August. Because congestion prices and costs were significantly higher in these two summer months than in previous months, FTR revenues for several paths were higher as well. For instance, the FTR revenue on Lugo-IPP DC was $5,151/MW due to congestion spikes in two days in July. Also, FTR revenues on Palo Verde respectively were $251/MW and $192/MW in July and August, higher than that reported in May and June. FTR revenues on Path 26 in the north to south direction continue to be unseasonably high: monthly revenues were $780/MW in July and $558/MW in August.

Table 11. FTR Revenue Per MW ($/MW), July-August 2003

Branch Group	Direction	Net $/MW FTR Rev Apr - Imp	Net $/MW FTR Rev May - Imp	Net $/MW FTR Rev Jun - Imp	Net $/MW FTR Rev Jul - Imp	Net $/MW FTR Rev Aug - Imp	Cumm Net $/MW FTRREV – Imp	Pro Rated NET $/MW FTRREV - Imp	FTR Auction Price
BLYTHE	IMPORT	69	0	231	1,422	376	2,097	6,292	$5,460
COI	IMPORT	723	536	299	138	352	2,047	6,142	$19,828
ELDORADO	IMPORT	0	0	1	0	0	1	2	$16,944
LUGOIPPDC**	IMPORT	272	0	0	5,151	8	5,430	16,291	N/A
LUGOTMONA**	IMPORT	0	715	7	0	15	737	2,211	N/A
LUGOWSTWG**	IMPORT	3	0	0	0	0	3	10	N/A
MEAD	IMPORT	166	0	14	150	85	414	1,241	$7,820
NOB	IMPORT	249	203	68	96	113	720	2,186	$12,245
PALOVRDE	IMPORT	233	15	5	251	192	697	2,091	$88,167
PATH26	IMPORT	0	0	5	0	0	5	14	$254
SUMMIT	IMPORT	108	0	0	0	0	108	325	$650
IID-SDGE	EXPORT	0	480	0	0	0	480	1,440	$182
PATH15**	EXPORT	0	5	0	0	0	5	15	N/A
PATH26	EXPORT	1,147	1,500	224	780	558	4,209	12,628	$8,602
SILVERPK	EXPORT	0	0	720	0	0	720	2,160	$100

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

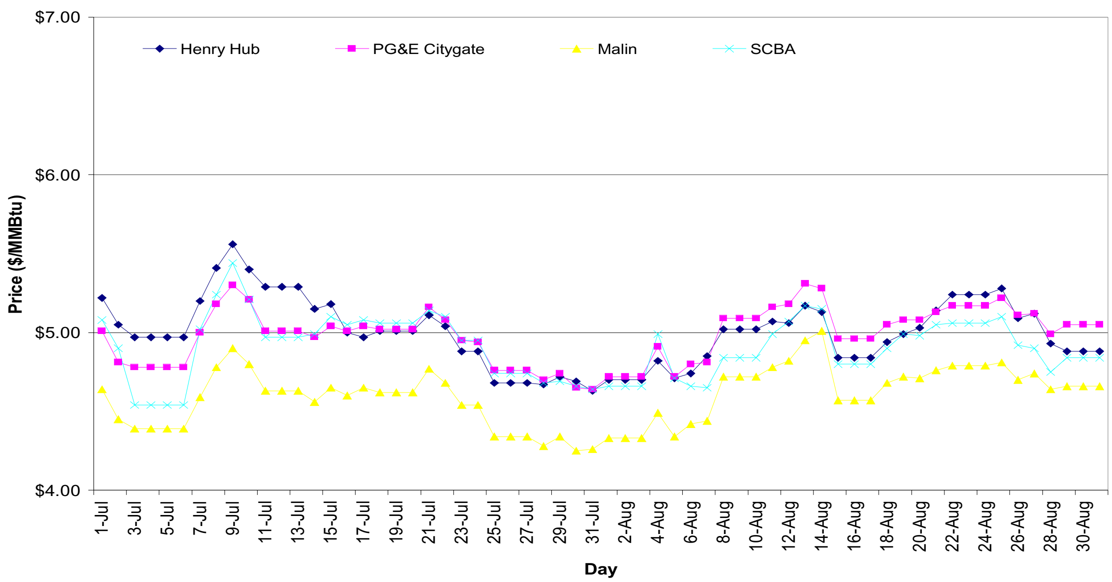
FTR Concentration There were no trades in the secondary FTR market in the July and August. Thus, the FTR owner concentration table reported in April remains in effect.

VI. Natural Gas Markets

Daily natural gas prices averaged approximately $5/MMBtu in July and August. Prices at Henry Hub were $4.54/MMBtu at Malin, $4.93/MMBtu at PG&E Citygate, and $4.92/MMBtu at Southern California Border Average during July 2003. Prices peaked on July 9 to $5.30 at PG&E Citygate and $5.44 at Southern California due to high cooling demand associated with a heat wave in the west. During the remainder of the month, prices steadily decreased. Average bid week prices for August were $4.90, $4.65, and $5.03 for SoCal Gas, Malin, and PG&E Citygate.

During August, daily prices averaged $4.97/MMBtu at Henry Hub, $4.65/MMBtu at Malin, $5.03/MMBtu at PG&E Citygate, and $4.89/MMBtu at Southern California Border Average. Higher NYMEX futures prices and increased cooling demand generated an increase of $0.33 from August 3 to August 4 at Southern California Border Average. After a few days of price decreases, gas prices steadily increased through August 12due to high cooling demand. Prices then receded by $0.15, but remained high through the end of the month. Average bid week prices for September were $4.84, $4.66, and $5.05 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 1%, unchanged, and unchanged, from August bid week prices. The following chart shows daily gas prices at regional delivery points for July and August.

Figure 11. Daily Gas Prices in July and August



Regional Bilateral-Traded Electricity Prices Regional day-ahead traded electricity prices averaged $51.44/MWh at the California-Oregon Border, $48.83/MWh at Mid-Columbia, $61.97/MWh at Palo Verde, $55.66/MWh in Northern California, and $59.52/MWh in Southern California on the weekdays in July. Prices spiked to monthly highs on July 17 owing to high cooling demand in Arizona, with forecasts of 115ºF in Phoenix. Prices throughout the remainder of July receded from the monthly high on July 17, ending at roughly $60/MWh in the Southwest and $55/MWh in the Northwest. In August, regional day-ahead electricity prices averaged $45.65/MWh at the California-Oregon Border, $42.78/MWh at Mid-Columbia, $52.81/MWh at Palo Verde, $50.40/MWh in Northern California, and $52.74/MWh in Southern California on the weekdays. Prices reached a monthly high in the Southwest on August 11 due to high temperatures in Southern California and Arizona. The following chart shows day-ahead bilateral electricity contract prices at regional trading hubs for July and August.

Figure 12. Day-Ahead Bilateral Electric Prices in July and August