Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: July 26, 2002

Re: Market Analysis Report for June 2002

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

Executive Summary

Total cost to load of energy and ancillary services (AS) averaged $40 per megawatt-hour (MWh) in June 2002, indicating relative stability in California's energy markets. Average real-time prices in June were slightly lower than in May, while average hourly load increased to 28,100 megawatts (MW), 2.3 percent above the level of June 2001. The average prices for real-time incremental (INC) and decremental (DEC) energy procured in June through the ISO's Balancing Energy Ex-Post Price auction market (the BEEP Stack) were $51.85 and $3.41/MWh, respectively.

Congestion costs exceeded $10 million in June, for the first time since November 2001, as wildfires and stability issues due to a planned unit outage at the Boardman plant in Southern Oregon forced derates of key transmission lines into northern California. Congestion has contributed significantly to disparities between day-ahead regional prices at Oregon and California trading points.

Despite the departure of the Sacramento Municipal Utility District (SMUD)[1] from the ISO Control Area on June 19, loads exceeded previous-year levels on certain days in late June, as hot weather spurred demand.

Ancillary service costs have consistently remained below three percent of energy costs since September 2001. Normal hydroelectric supply, stable prices for natural gas, healthy imports, moderate demand, long-term contracting, and West-wide mitigation, ordered by the Federal Energy Regulatory Commission (FERC) on June 19, 2001, have all been integral in keeping energy costs under control in the ISO Control Area.

[1] SMUD has a peak load of around 2600 MW.

While market indicators show signs of health, significant risk factors persist. System capacity reserve margin remains low, while load is increasing during the peak summer months; investment in new generation has all but ceased as generators face credit concerns; import generation has not always been dependably available when needed; and the development of price-responsive demand has been slow. Markup in the price of real-time energy is indicative of the potential for the exercise of market power.

To mitigate these remaining risks, changes in fundamental structures must be carried forward. These changes include the ability of load to enter into long term contracts, aggressive development of price responsive demand, and supply-side reform. The ISO's 2002 Market Redesign (MD02) project, to be implemented beginning October 2002, features strengthened market power mitigation measures, including a continuation of the obligation on sellers to offer all available generating capacity and a West-wide price cap. Further reforms in market structure are needed including the assurance of long-term investment in generation and transmission.

I. Energy Market Statistics

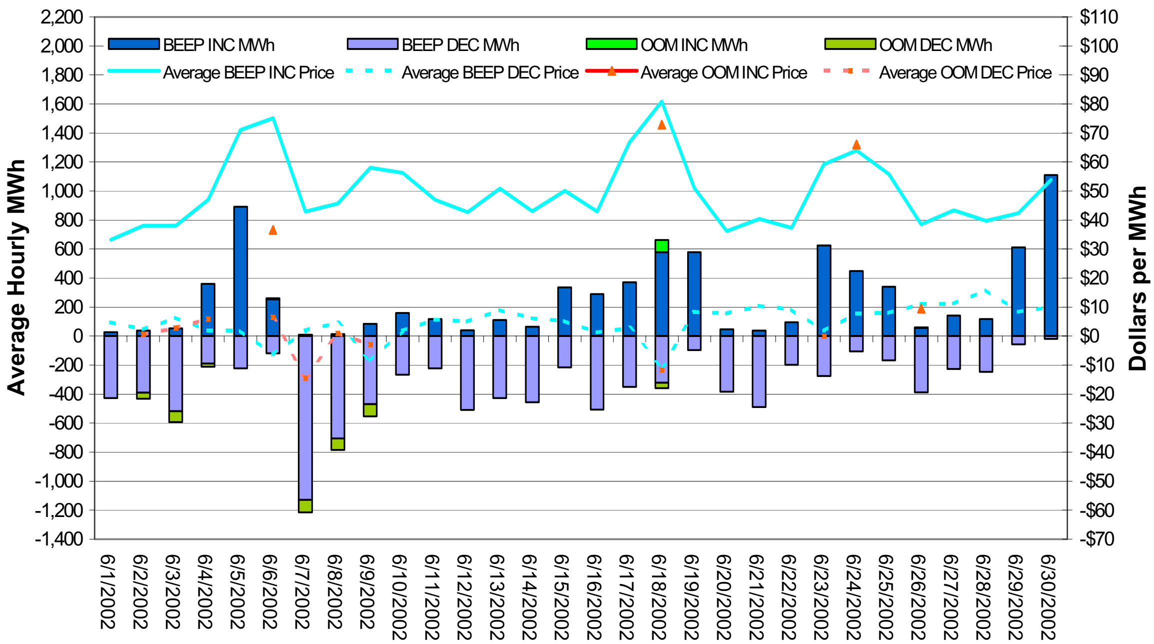
Loads. ISO load totaled 20,232 GWh in June, or an average of 28,100 MW during the month.[2] In comparison, load averaged 27,468 MW in June 2001 and 26,465 MW in May 2002.

Conservation. The California Energy Commission (CEC) estimates conservation as the change in monthly peak load, adjusted for growth and weather conditions. The CEC reports that adjusted monthly peak load in June was 3.3 percent above the June 2001 peak, but was 11.2 percent lower than the June 2000 peak.

Real-Time BEEP Prices and Volumes. June prices were slightly more moderate than those in May, despite the increases in out-of-market (OOM) procurement and BEEP as-bid procurement above the soft price cap. The overall average real-time prices for incremental (INC) and decremental (DEC) balancing energy procured by the ISO on behalf of load were $51.90 and $3.41/MWh, compared with $54.13 and $3.96/MWh in May, respectively. INC and DEC volumes were 195 and 252 GWh for the month, respectively. Real-time volumes increased 18 and 22 percent in June for INC and DEC procurement from May levels, respectively. Specifically, volumes averaged 520 and 452 MW in hours in which the ISO made INC and DEC procurements in June, respectively, compared with 440 MW and 372 MW in May.[3] The following chart shows BEEP and OOM procurement in June.

[2] This average includes the SMUD load until it exited the ISO Control Area on June 19.
[3] The average INC and DEC purchases of 260 MW and 220 MW for May in last month's report were erroneously reported as averages in which INC or DEC energy respectively was procured. These numbers in fact represent averages over all 744 hours in May.

Figure 1. ISO Real-Time Prices and Volumes June 2002



As-Bid Procurement. The ISO procured as-bid energy in one peak afternoon hour on June 6 and in two afternoon hours on June 18. In all of these cases, the ISO had lost use of the Midway-Vincent lines of Path 26 due to fires. To manage the transmission loss, ISO operators simultaneously incremented generation in SP15 and decremented generati

Real-Time OOM Procurement. Because the volume of bids into the BEEP Stack was not always sufficient to balance generation with load, ISO operators resorted to OOM calls in 29 of 720 hours in June. These hours fell into two categories. Most were late-night or morning-ramp hours in which scheduling coordinators (SCs) had scheduled generation in excess of actual load, which forced the ISO to make decremental OOM calls after exhausting DEC bids into the BEEP Stack, to compensate for the overscheduling. Others were during hot afternoon hours when SCs had underscheduled generation, forcing the ISO to dispatch more incremental energy than was offered into the BEEP Stack to balance generation with load.

The ISO monitors key price and volume statistics for real-time energy transactions. The following table shows (1) average prices and total volumes for real-time energy procured through the BEEP Stack. Also shown are (2) average OOM prices and volumes. The combination of (1) and (2) comprise (3) average real-time prices and total volumes of all real-time balancing energy. The final column (4) shows average system loads and percent underscheduling.

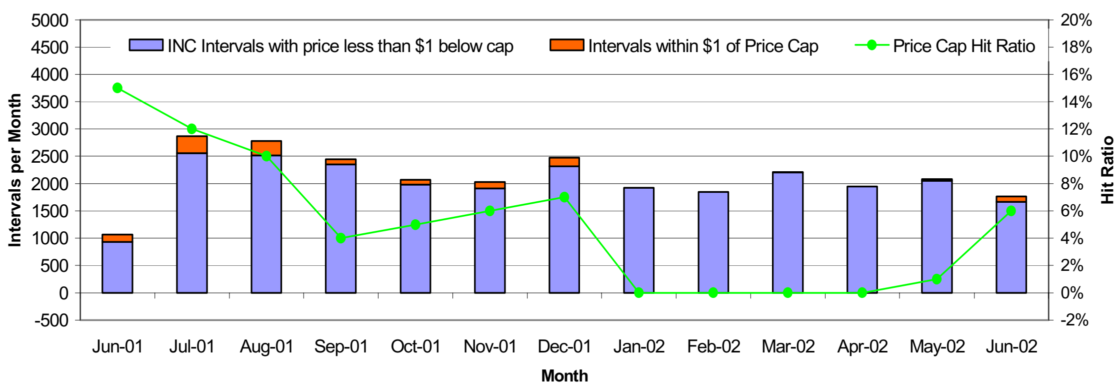
Table 1. Real-Time Energy Statistics for June 2002

	Avg. BEEP Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads (MW) and Pct. Underscheduling (4)
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$ 52.90	$ 5.79	$ 72.87	$ (12.87)	$ 53.16	$ 5.43	30,427 MW
	173 GWh	154 GWh	2 GWh	3 GWh	175 GWh	157 GWh	3%
Off-Peak	$ 41.01	$ 0.44	No Procurement	$ (3.93)	$ 41.01	$ 0.11	23,444 MW
	20 GWh	88 GWh		7 GWh	20 GWh	96 GWh	1%
All Hours	$ 51.65	$ 3.83	$ 72.87	$ (6.52)	$ 51.90	$ 3.41	28,100 MW
	193 GWh	242 GWh	2 GWh	10 GWh	195 GWh	252 GWh	2%

Price Cap Hits. The ISO monitors the frequency with which the BEEP MCP comes within $1 of the current soft price cap. Pursuant to the FERC Orders of June 19 and December 19, 2001, the cap stood at $91.87 throughout June, although it dropped below that level for two days in July.

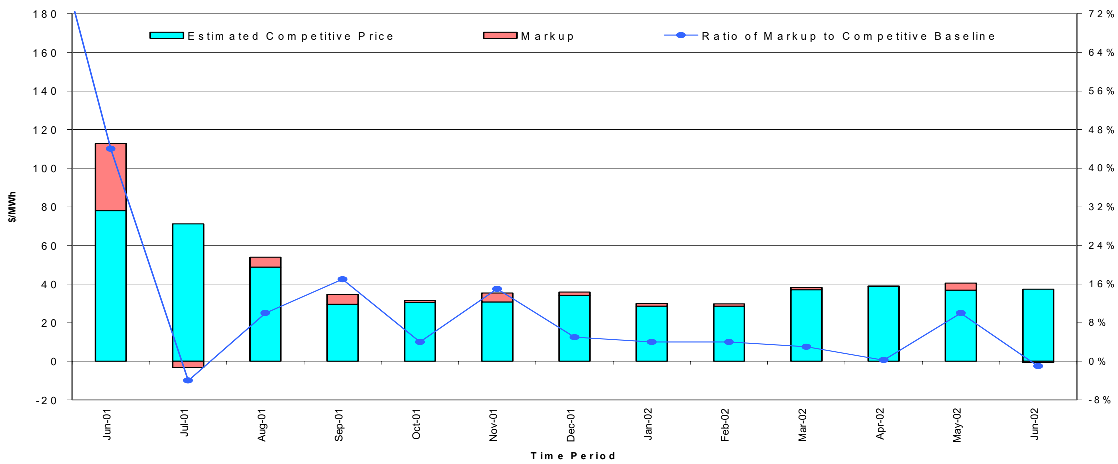
As rising temperatures have stimulated electricity demand for cooling, price cap hits in the late afternoon hours have occurred more often, and lately have reached frequencies not seen since late 2001. The MCP came within $1 of the price cap or exceeded it in 32 of 1,498 intervals (2 percent) in which the ISO procured incremental energy in NP15, and in 98 of 1,668 such intervals (6 percent) in SP15, chiefly during the peak afternoon hours. The following chart shows monthly price cap hits in SP15 since June 20, 2001.

Figure 2. Price Cap Hits in SP15 by Month



Market Power. Market power is often measured by comparing the price paid for energy to an estimate of the price that would exist under competitive conditions. The Department of Market Analysis (DMA) tracks one such index, the price-to-cost markup for short-term energy, by calculating the ratio of the markup of prices in California's short-term energy markets to the estimated competitive price. A perfectly competitive market would be indicated by the index equal to zero (no percentage markup). The following table shows the price-to-cost markup in short-term energy (includes day ahead bilateral and real-time) since June 2001. Price-to-cost markup has been manageable in recent months as adequate reserve margins have been available.

Figure 3. Price-to-Cost Markup in Short Term Energy



II. Ancillary Services

The ISO monitors AS prices and volumes by type and market. Costs for AS rose to $20 million in June, up from $15 million in May, as the increase in load necessitated the purchase of additional capacity reserves. Prices of all service types rose significantly between May and June. Average day-ahead prices for Upward and Downward Regulation respectively were $16.22 and $18.27/MWh in June, compared with $14.08 and $16.68/MWh in May. Average day-ahead prices for Spinning and Non-Spinning Reserves respectively were $6.61 and $3.88/MWh in June, compared with $4.43 and $1.30/MWh in May. The average day-ahead price for Replacement services was well above normal at $2.93/MWh in June, up from $0.08/MWh in May. The Rational Buyer optimization algorithm procured only 57 MWh of Replacement services in June, instead selecting other products when their prices were lower. The following table shows AS prices and volumes by market.

Table 2. AS Prices and Volumes by Market

	Day-Ahead Market	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$ 16.22	$ 16.63	$ 16.25	501	39	92%
Regulation Down	$ 18.27	$ 10.14	$ 17.43	446	52	89%
Spin	$ 6.61	$ 4.22	$ 6.55	828	24	97%
Non-Spin	$ 3.88	$ 1.67	$ 3.80	755	29	96%
Replacement	$ 2.93	$ 1.50	$ 2.94	57	*	100%

* Indicates procurement below 1 MW.

III. Interzonal Congestion

As noted earlier in this Report, congestion costs rose to the highest levels seen since 2001, as line deratings due to fires and other constraints forced curtailments. Congestion costs totaled approximately $10.3 million in June, of which $8.9 million was incurred in the day-ahead adjustment market. As is customary for summer months, most congestion costs were incurred in the southbound direction. That is, interties from Oregon into the ISO Control Area primarily incurred costs in the import direction; and interties from the ISO Control Area to Los Angeles and the Southwest incurred costs primarily in the export direction.

The two lines that sustained the bulk of the charges were COI, in the import direction, and the McCullough Intertie, which connects the ISO SP15 area with the Los Angeles Department of Water and Power Control Area, in the export (to Los Angeles) direction. COI incurred $4.6 million of day-ahead congestion costs in the import direction, as hot weather prompted high load levels in California, and fires near key transmission lines limited flows into the ISO Control Area. A scheduled plant outage at the Boardman plant in Oregon also necessitated derates, in order to ensure stability of the grid. Charges on McCullough, which totaled $3.8 million, are currently under review and investigation by DMA. Path 26, which was derated to 500 MW on June 18 due to fire, was also congested in the day ahead in both import and export directions in different hours.

The average peak-hour congestion price on COI of $24.96 reflects the difference in prices seen throughout much of June between day-ahead energy at the Mid-Columbia and California delivery points.

The following table shows day-ahead congestion statistics for June. The congestion percentage refers to the percentage of peak, off-peak, or overall hours during the month in which a given path is congested in a given direction.

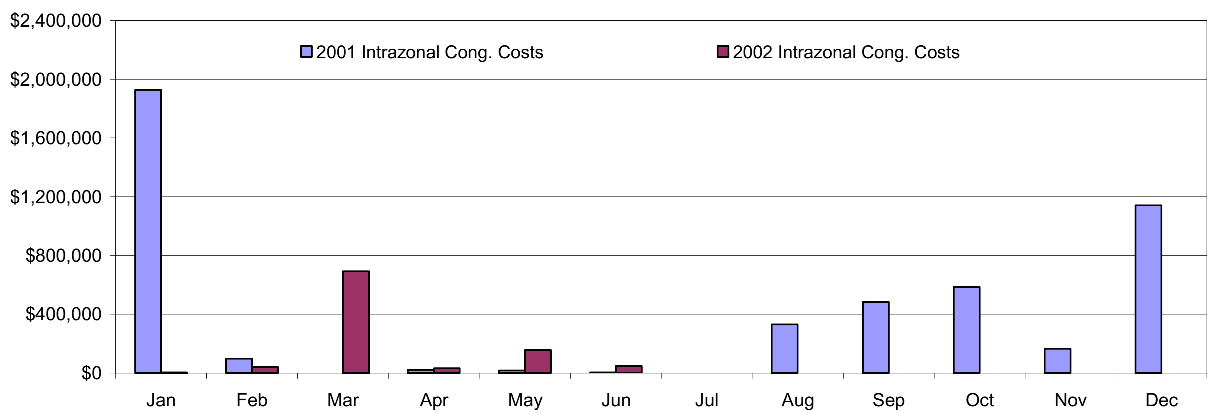
Table 3. Day-Ahead Interzonal Congestion Frequencies and Prices And Total Congestion Costs for June 2002

Branch Group and Direction	Peak Congestion Pctg.	Off-Peak Congestion Pctg.	All-Hour Congestion Pctg.	Avg. Peak Congestion Price	Avg. Off-Peak Congestion Price	Avg. All-Hours Congestion Price	Total Congestion Cost (DA + HA)
Cascade (Import)							$3,234
COI (Import)	22.9%	20.4%	22.1%	$24.96	$22.56	$24.22	$5.1 million
Eldorado (Import)							$1,378
McCullough (Export)	19.4%		12.9%	$164.57		$164.57	$3.8 million
NOB (Import)	60.2%	5.0%	41.8%	$0.17	$0.01	$0.16	$0.1 million
Path 15 (South-to-North)	6.9%	37.9%	17.2%	$0	$0	$0	$0.3 million
Path 15 (North-to-South)	0.2%	0.0%	0.1%	$44.82		$44.82	$6,007
Path 26 (South-to-North)	0.0%	7.5%	2.5%		$32.10	$32.10	$0.2 million
Path 26 (North-to-South)	4.8%	0.0%	3.2%	$3.61		$3.61	$0.3 million
Summit (Import)							$810
Sylmar-AC (Import)							$9,436
Victorville (Export)							$0.5 million
Total Costs							**$10.3 million**

IV. Intrazonal Congestion

Intrazonal congestion, exclusive of reliability must-run (RMR) costs, has been moderate since April 2002. In June, intrazonal costs totaled approximately $47,000.

Figure 4. Intrazonal Congestion Costs (Excluding RMR Costs) in 2001 and 2002



V. Summary of Market Costs

DMA estimates that wholesale cost to load for energy and ancillary services totaled $816 million in June, or an average of approximately $40/MWh, compared with $41/MWh in May. Stability in market costs has been brought about by near-normal hydroelectric conditions in California and the Northwest new thermal generation resources in California, and moderate loads. The following tables show costs for wholesale energy and AS for 2002 to date, including actuals from the California Department of Water Resources' California Energy Resources Scheduling Division (CERS) for March and April, and estimates of bilateral purchases at day-ahead hub prices. CERS costs for May and June are estimates; actuals for these months are expected to be available in the July-August report, to be released in September.

Table 4a. Energy Cost Summary for 2002

	ISO Load (GWh)	Forward Energy (GWh)*	Est Forward Energy Costs (MM$)**	RT Energy Costs (MM$)***	A/S Costs (MM$)****	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
Jan-02	19,356	18,940	$ 737	$ 7	$ 19	$ 744	$ 763	$ 38	$ 0.97	2.5%	$ 39
Feb-02	17,153	16,654	$ 663	$ 7	$ 12	$ 670	$ 682	$ 39	$ 0.68	1.7%	$ 40
Mar-02	18,749	18,282	$ 811	$ 6	$ 9	$ 817	$ 826	$ 44	$ 0.50	1.2%	$ 44
Apr-02	18,511	17,937	$ 742	$ 8	$ 13	$ 750	$ 763	$ 41	$ 0.68	1.7%	$ 41
May-02	19,690	19,031	$ 774	$ 11	$ 15	$ 786	$ 801	$ 40	$ 0.78	2.0%	$ 41
Jun-02	20,232	19,691	$ 786	$ 10	$ 20	$ 796	$ 816	$ 39	$ 0.97	2.5%	$ 40
Total 2002	113,691	110,535	$ 4,513	$ 50	$ 88	$ 4,563	$ 4,651				
Avg 2002	18,949	18,422	$ 752	$ 8	$ 15	$ 760	$ 775	$ 40	$ 0.76	1.9%	$ 41

* Sum of hour-ahead scheduled quantities

** Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices

*** includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid

**** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

May and June forward costs (and resulting totals) are estimated. Values in report to be released in September will include true-up and may differ from values shown here.

Table 4b. Energy Cost Summary for 2001 and Earlier

	ISO Load (GWh)	Est Forward Energy Costs (MM$)*	RT Energy Costs (MM$)**	A/S Costs (MM$)***	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
Total 2001	227,024	$ 21,248	$ 4,162	$ 1,346.09	$ 25,409.97	$ 26,756				
Avg 2001	18,919	$ 1,771	$ 347	$ 112	$ 2,117	$ 2,230	$ 115	$ 6.07	5.3%	$ 118
Total 2000	237,543	$ 22,890	$ 2,877	$ 1,720	$ 25,373	$ 27,083				
Avg 2000	19,795	$ 1,907	$ 240	$ 143	$ 2,114	$ 2,257	$ 107	$ 7.24	6.8%	$ 114
Total 1999	227,533	$ 6,848	$ 180	$ 404	$ 7,028	$ 7,432				
Avg 1999	18,961	$ 571	$ 15	$ 34	$ 586	$ 619	$ 31	$ 1.78	5.7%	$ 33
1998 (9mo)	169,239	$ 4,704	$ 209	$ 638	$ 4,913	$ 5,551				
Avg 1998	18,804	$ 523	$ 23	$ 71	$ 546	$ 617	$ 29	$ 3.77	13.0%	$ 33

1998-2000:

* Forward costs include estimated PX and bilateral energy costs.
  Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.
  Estimated Bilateral Energy Cost based on the difference between hour-ahead schedules and PX quantities, valued at PX prices.

** Beginning November 2000, ISO Real Time Energy Costs include OOM Costs.

2001 only:

***** Sum of hour-ahead scheduled costs. Includes UDC (cost of production), estimated CDWR costs, and other bilaterals priced at hub prices

****** includes OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid

All years:

******* Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

VI. Firm Transmission Rights

No secondary FTR market trades or scheduling coordinator reassignments occurred in June. Hence, the FTR ownership concentrations for the 2002-2003 FTR cycle, reported in the January-February 2002 Market Analysis Report, remain unchanged.

On some paths, FTRs were used to establish the scheduling priority in the day-ahead markets. As shown in the following table, a high percentage of FTRs was scheduled on certain paths (e.g. 88% on Eldorado, 73% on IID-SCE, 55% on Palo Verde, and 100% on Silver Peak in the import direction). FTRs on those paths are held primarily by Southern California Edison Company (SCE1). FTRs on most other paths were employed chiefly for their function of hedging against transmission usage charges.
The following tables show FTR scheduling statistics for June. These indices include the volume of megawatts of FTRs auctioned (i.e. the total FTR resources held by FTR owners) for each path; the hourly average MW of FTRs scheduled; the maximum FTRs scheduled in any hour during the month; the maximum FTR schedule for any single SC during the month; and the percent of FTRs scheduled, defined as the ratio of the average FTR schedule to the MW of FTRs auctioned.

Table 5. FTR Scheduling Statistics

	COI (Import)	Eldorado (Import)	IID-SCE (Import)	Mead (Import)	NOB (Import)	Palo Verde (Import)	Silver Peak (Import)	Victorville (Import)
MW FTR Auctioned	658	793	600	478	698	1167	10	926
Avg. MW FTR Sched.	172	700	435	22	102	640	10	21
Max MW FTR Sched.	200	700	440	178	162	805	10	61
Max Single SC FTR Schedule	150	700	440	178	150	579	10	50
% FTR Scheduled	26%	88%	73%	5%	15%	55%	100%	2%

	Eldorado (Export)	Mead (Export)	Palo Verde (Export)	Path 26 (North-to-South)
MW FTR Auctioned	793	478	1167	926
Avg. MW FTR Sched.	700	22	640	21
Max MW FTR Sched.	700	178	805	61
Max Single SC FTR Schedule	700	178	579	50
% FTR Scheduled	88%	5%	55%	2%

FTR Revenue per Megawatt. FTR revenues were unusually high on COI in the import direction ($4,129/MW) and on Path 26 in the South-to-North direction ($370/MW), and on Victorville in the export direction ($724/MW). The following table summarizes FTR revenue per MW for June.

Table 6. Revenue per MW of FTR owned in June

Path	Direction	Revenue ($/MW)
COI	Import	$ 4,129
Eldorado	Import	$ 2
NOB	Import	$ 48
Path 26	South-to-North	$ 370
Path 26	North-to-South	$ 125
Victorville	Export	$ 724

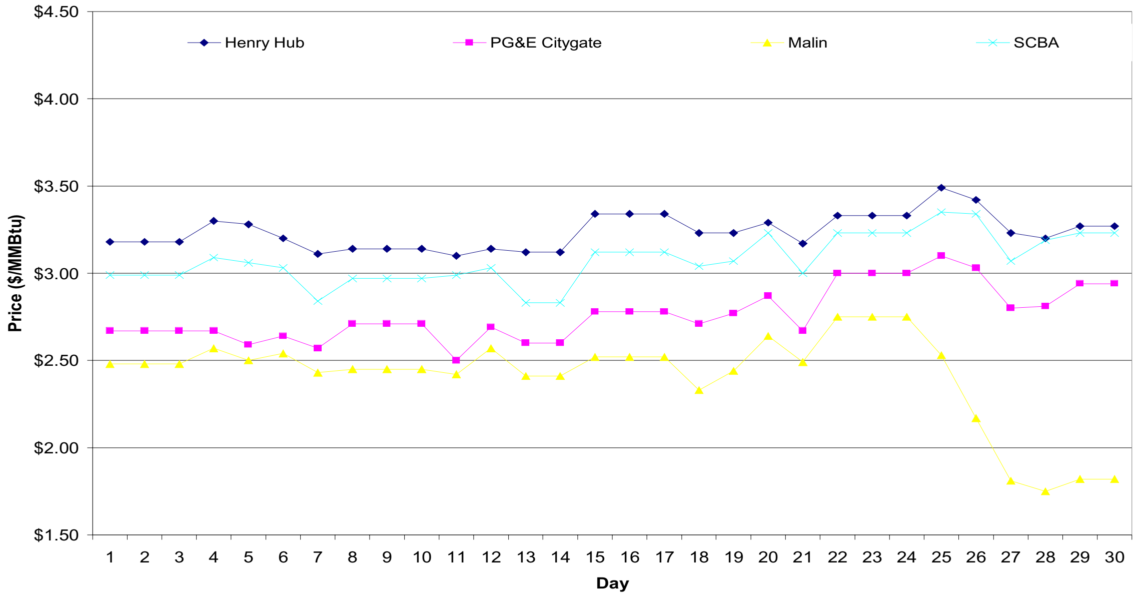
VII. Natural Gas Markets

Henry Hub natural gas prices were consistently higher than California prices throughout June. During the month, Southern California Border Average prices exceeded PG&E Citygate and Malin prices by $0.50/MMBtu or more, due to abundant hydro resources in the Northwest and cooling demand driven by high temperatures in the Southwest. Natural gas prices began June between $2.45 and $3.25/MMBtu. From June 4 through June 6, prices increased at Henry Hub and Southern California owing to high temperatures through the southern United States, but quickly returned to pre-June 4 levels due to high natural gas supply conditions. Aside from this temporary increase, natural gas prices remained stable until June 14, despite relatively high temperatures through much of Southern California, as natural gas supplies were high.

Futures price increases and the continued demand arising from hot weather caused natural gas prices to increase by $0.05 to $0.20/MMBtu across all hubs on June 15, where prices stood until June 24. Warm temperatures in the southwest resulted in a transitory increase in Henry Hub, PG&E Citygate and Southern California Border Average prices on June 24. However, reduced cooling demand owing to cooling temperatures in the northwest resulted in sharply lower natural gas prices at Malin, where prices settled at $1.75/MMBtu until the end of the month. Average bid week prices for July were $3.31, $2.62, and $2.89 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 15%, 0%, and 9% from June bid week prices.

The following chart shows daily gas prices for June.

Figure 5. Daily Gas Prices for June



VIII. Regional Electricity Markets

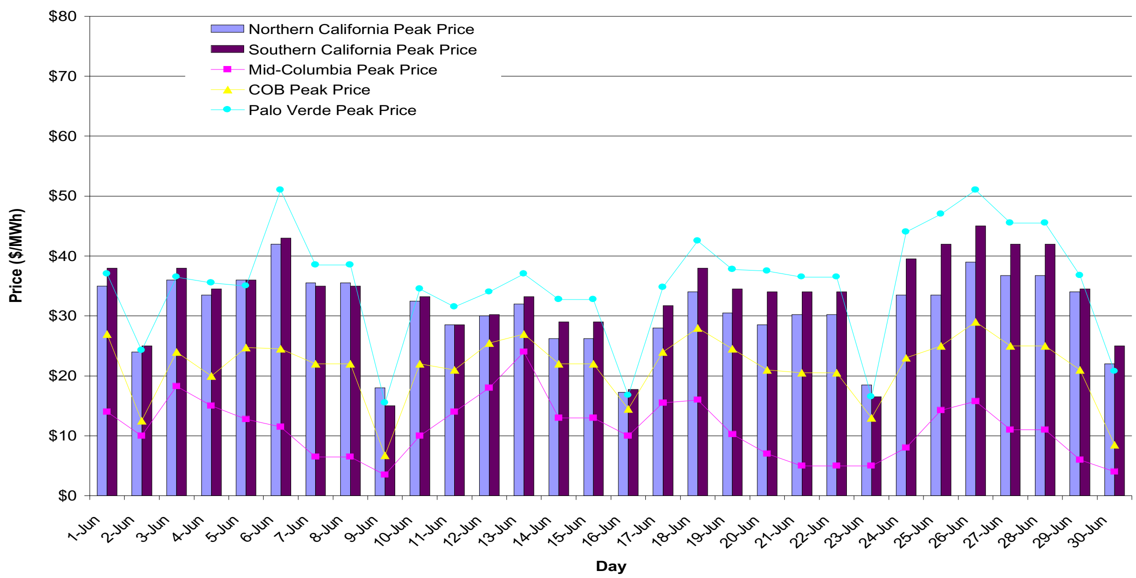
High cooling demand due to high temperatures throughout the Southwest caused regional electricity prices in Southern California and at the Palo Verde hub in Arizona to be consistently higher than Northern California and Northwest hub prices. Additionally, prices at the California-Oregon Border (COB) and Mid-Columbia (Mid-C) hubs were lower than California prices, due to lower cooling demand in the Northwest, plentiful hydroelectric power, and congestion on interties used to import power from the Northwest to California.

Between June 1 and June 10, Palo Verde and California prices stayed fairly stable at between $35 to $40/MWh, with an exception on June 6, when forecasts of unusually hot weather in the Southwest caused prices to spike above $50/MWh at the Palo Verde hub and above $40/MWh at the California hubs. COB prices remained within the $20-to-$30/MWh range. From June 3 to June 9, Malin prices fell from $19/MWh to below $5/MWh as increases in hydroelectric generation produced greater supply. Between June 11 and June 17, Palo Verde and California prices remained within the $25 to $37/MWh price range, while Malin prices moved toward a monthly high of $24/MWh on June 13, as cooling demand was forecasted to peak at 2.5 times normal levels that afternoon. After June 13, cooling demand decreased, causing Malin prices to return to the $10 to $15/MWh range.

A heat wave in the Southwest increased cooling demand in Southern California and at Palo Verde, along with associated increases in electricity prices from June 17 to 28. Southern California prices increased to the $30 to $40/MWh range, $2 to $3/MWh higher than Northern California prices between June 17 and 22, and to the $37 to $45/MWh range between June 24 and June 28. Palo

Verde prices ranged between $44 and $52/MWh between June 24 and 28. Northwest prices, however, remained low between June 17 and 22, owing to low cooling demand and high hydroelectric generation. As temperatures increased in the Northwest from June 24 to 28, Northwest power prices increased to $16/MWh, and then settled between $4 and $25/MWh on the final days of the month as electricity demand subsided for the weekend.

Figure 6. Daily Regional Electricity Prices for June



IX. Issues under Review

Oversight and Investigation Activities Project. DMA staff is providing key support to the ISO's Oversight and Investigation Activities Review project. This involves analysis of the necessary enhancement to the ISO's responsibility, authority, and activities in market monitoring, investigation and enforcement. As a first step in this project, the ISO distributed a white paper presenting objectives, guiding principles and a preliminary framework for a proposal on June 21. The white paper described the following elements:

1) Potential changes to the ISO's use of authority under its existing Tariff, to encourage compliance, and to discourage conduct that is detrimental to system reliability and market efficiency.

2) Revisions to the Market Monitoring and Information Protocol (MMIP), to enhance the ISO's authority to investigate gaming and market manipulation effectively.

3) The development of a new “Market Enforcement Protocol” that would specify market rules; clarify and document the investigation process; define warnings, penalties and sanctions as necessary to provide effective deterrents to misbehavior; and identify the specific conditions under which sanctionable behavior will or will not be prosecuted.

The project will be completed in two phases.

In the first phase, the ISO will identify actions it may take that do not require tariff revisions, such as unannounced testing of Ancillary Services and the ISO’s proposal for use of the “committed period” penalty (described in the June 21 white paper). Meanwhile, the ISO will establish appropriate procedures for ISO investigations and for reporting behavior under the MMIP. This would include details such as rules for publishing the identities of Market Participants that engage in misbehavior.

In the second phase, the ISO intends to develop and to seek FERC approval for Tariff changes to specify or clarify particular requirements or prohibitions of activities that are detrimental to system reliability and/or market efficiency. The ISO will seek additional authority to conduct investigations and impose penalties and sanctions for violations of obligations under the ISO Tariff.

The current work plan calls for implementation of various actions under its current tariff authority over the second half of 2002, and calls for any potential tariff changes developed through the project to be submitted to the ISO Board of Governors at its Meeting on September 19, for possible filing with FERC by the end of September.

Investigations of 2000-2001 Market Activity. DMA staff continues to work with a multitude of Federal and State legal and regulatory entities to investigate anomalous market activity during the 2000-2001 period.

As part of these investigations, DMA continues to provide information to those entities on energy trading practices outlined in Enron memoranda released by FERC last spring (see April Market Analysis Report), and other variations of these practices. Results of DMA analyses are being provided to other regulatory/legal entities, and are also being utilized by DMA to monitor and to identify variations of these practices on a going-forward basis. Updated summary results of this analysis were included in testimony that ISO chief executive officer Terry Winter provided to the United States House of Representatives’ Committee on Government Reform, Subcommittee on Energy Policy, Natural Resources, and Regulatory Affairs, at its Hearing on Energy Trading in California on July 22, 2002.

DMA is also assisting in the investigation of a widely publicized incident involving potential “Ricochet” schedules submitted on November 11, 2000, which was made public in recent hearings by the California State Senate’s Select Committee to Investigate Price Manipulation of the Wholesale Energy Market. This Committee has requested that the ISO provide it with a detailed summary of any findings the ISO may have relating to this incident.
Other investigations of anomalies are continuing on an ongoing basis.

ACAP Design. DMA has actively participated in the design of the Availability Capacity Obligation (ACAP). A revised ACAP design takes into account key elements of the Advisory Forward Energy Commitment (AFEC) proposed by the California State Inter-Agency Working Group. Since the release of the ACAP design on May 1, and the filing of ACAP Tariff and protocols on June 17 with FERC, DMA and the ISO Policy Office have had discussions with Stakeholders and State Officials, and are continuing to enhance the ACAP design by incorporating feedback from these parties. Examples of topics to be addressed include procedures for treating curtailable demand when it is used to meet the ACAP obligation, and the obligation of a LSE whose energy derivative contracts cover its own capacity obligation during peak hours, but may be used to cover a capacity-deficient LSE in non-peak hours.