CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers, ISO Board Assistants

Date: September 14, 2001

Re: Market Analysis Report for July 2001

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

This report summarizes key market conditions, developments, and trends for July 2001.

EXECUTIVE SUMMARY

Real time electricity and ancillary service prices decreased in July compared to June due to high generation availability and lower natural gas prices. On average, the price of real time electricity in July decreased 40% to $63/MWh from the June average of $104/MWh. Although loads increased in July compared to June as warmer temperatures increased cooling demand, loads declined from July 2000 levels showing visible conservation efforts. Total load in July was down 4.37% from July of last year. The California Energy Commission (CEC) provides refined estimates of conservation after normalizing for growth and weather conditions. In July, the CEC calculated that the growth and weather normalized demand for monthly energy dropped by 5.2 percent from July 2000.

On June 20, 2001, the FERC's June 19, 2001 price mitigation order for Western electricity markets went into effect. The order caps prices during all hours at a formula determined proxy price[1]. Bids accepted above the price cap are paid as bid subject to cost justification or refund. During the stage emergencies, the proxy price is determined by calculating the marginal cost of the highest priced unit dispatched. In non-emergency hours, the cap is set equal to 85 percent of the highest hourly ex-post price set during the last full hour of operation under an ISO declared Stage 1 emergency. FERC's June 19 mitigation initially capped prices at $91.87/MWh throughout the west for non-emergency hours, 85 percent of the highest hourly ex-post price calculated during the ISO's last Stage 1 emergency (which was $108.08/MWh and occurred in hour ending 10:00 on May 31, 2001). The cap remained unchanged throughout July because the ISO did not operate under a stage 1 emergency for a full hour during the month. The cap will be reset upon the next full hour of a Stage 1 emergency.

A preliminary review shows that the FERC's June 19 Order has been somewhat effective in mitigating real time prices. Figure 1 shows the reduction in the real-time price was due two factors: in part due to the reduction in production costs as well as the reduction in the mark-up suppliers charged over costs. However, high bids continue to be submitted in the real-time market which could cause an increase in the measure of mark-up suppliers charged over costs in the event that demand rises to levels where the ISO is forced to accept these bids.

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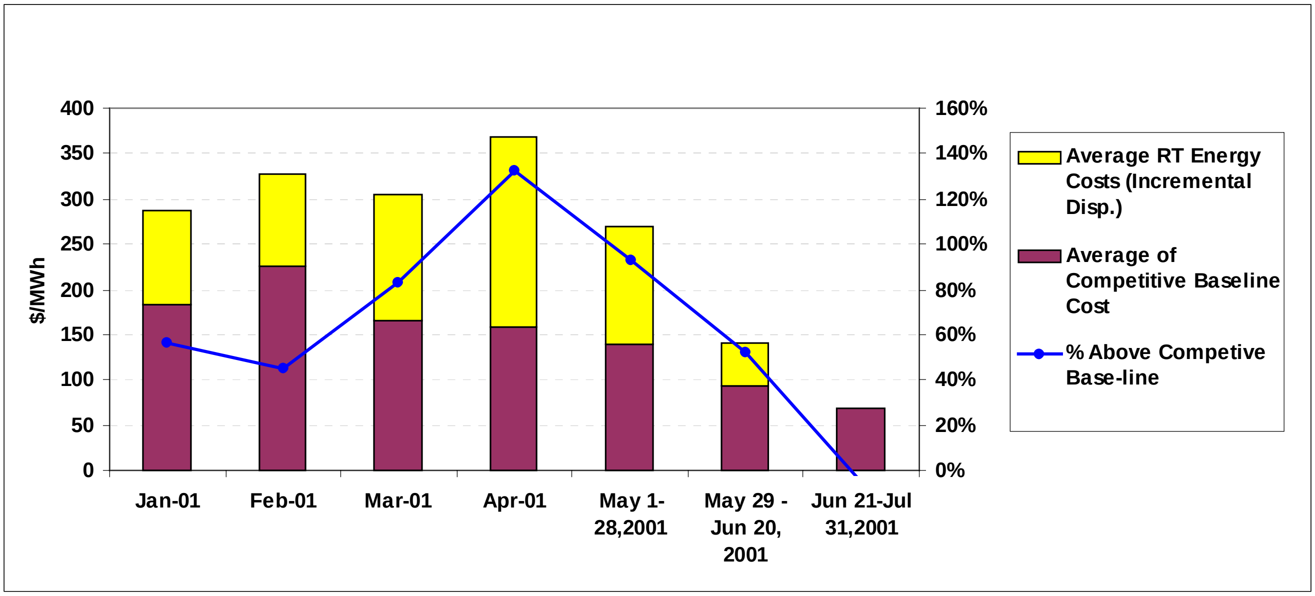
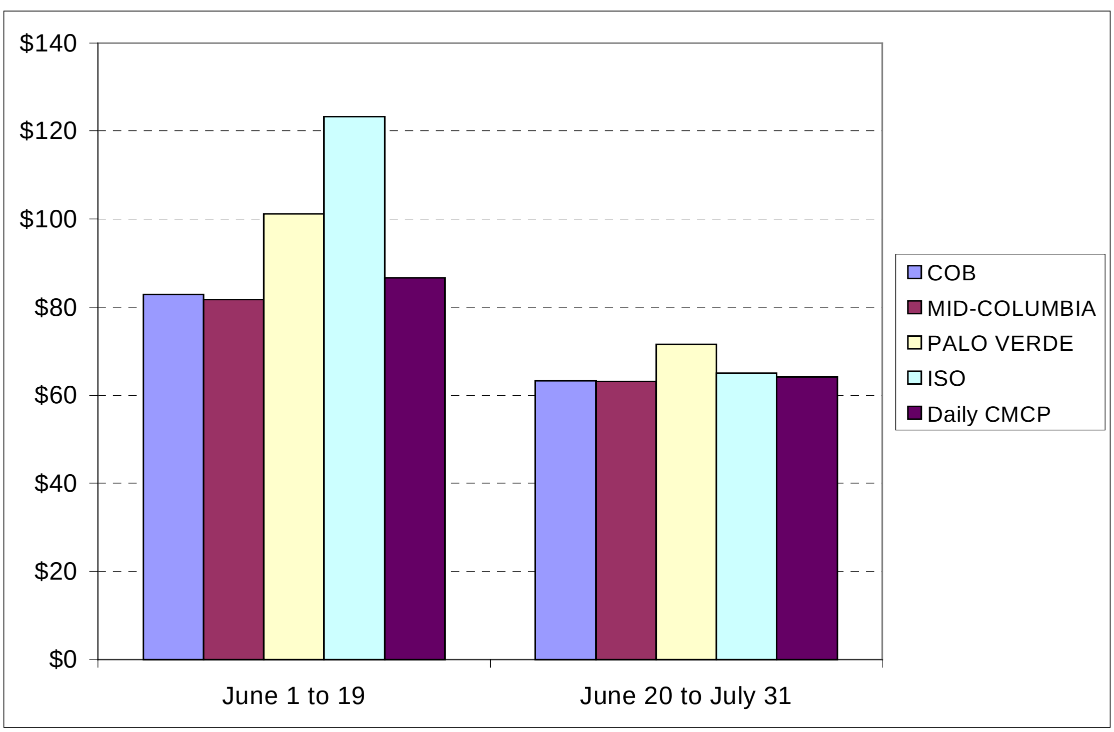
[1] FERC ordered a 10 percent adder to the market-clearing price for generators selling into the ISO markets to account for increased credit risk.

Figure 1. Price-Cost Mark-Up in ISO Real-Time Market



Comparing the competitive baseline cost to other Western regional spot market prices, we see a similar reduction in the mark-up of suppliers in those markets as well. Figure 2 shows peak period spot prices for California Oregon Border, Mid-Columbia, Palo Verde, and the ISO real-time price compared to a California competitive baseline cost. However, it should be noted that the California competitive baseline is not necessarily representative of the costs of other regional suppliers.

Figure 2. Regional Spot Prices Compared to Daily Competitive Baseline



Other key market activities include the following:

- **Regional spot electricity prices decreased in July from June**. Low natural gas prices and increased generation availability put downward pressure on prices. Overall, regional prices reported in the Northwest were 15% lower than “effective real time energy prices” in NP15, while regional prices reported in the Southwest were only 3% lower than “effective real time energy prices” in SP15. Since the trading volume at the reported regional spot prices is unknown, it is difficult to make direct comparison to California volume and spot prices.

- **Spot natural gas prices decreased from $5.28/MMBtu in June to $3.99/MMBtu in July**. The California average natural gas spot price is the average of the PG&E Citygate and Southern California Border prices. The decrease in prices was due to milder weather conditions leading to less cooling demand combined with increased generation availability of nuclear and hydro generation resources reducing demand for gas fueled generation.

- **Underscheduling of loads and generation remains low**. The California Energy Resources Scheduling division of the California Department of Water Resources (CERS) purchases limited the underscheduling of loads to an average of 1.8 percent in July.

- **Lower Ancillary Service Costs.** In July, ancillary service prices decreased significantly compared to June as ancillary service costs decreased by 62%. Total ancillary service costs were $71 million in July, down from the June total of $187 million, representing a decrease from $9.48 to $3.37 per MWh of load served.

- **Low Congestion Costs.** Congestion in July was primarily limited to hour-ahead exports on Victorville, day-ahead congestion on Path 15 in the south to north direction (all during off-peak hours), and exports to the Northwest on NOB. Total congestion costs for July were approximately $0.9 million, up from $0.6 million in June.

KEY MARKET CONDITIONS FOR JULY 2001

I. California Wholesale Energy Markets

- **Loads.** Monthly system energy loads for July totaled 20,976 GWh, a 4.37% decrease from July 2000, reflecting significant conservation efforts by California consumers. The peak load for the month reached 40,241 MW, a 6.9% decrease from the July 2000 peak of 43,334 MW. Daily peak loads averaged 33,390 MW, a 7.9% decrease from July 2000. The California Energy Commission provides refined estimates of conservation after normalizing for growth and weather conditions. In July, the CEC calculated that monthly peak demand for electricity dropped by 10.7 percent from July 2000 and monthly energy dropped by 5.2 percent on a growth and weather normalized basis.

- **Wholesale Energy Prices.** On June 20, the FERC's West-wide system mitigation went into effect initially capping real-time energy and ancillary services prices at $91.87/MWh throughout the WSCC during all California ISO non-emergency hours.[2]. The order caps prices during all hours at a formula determined proxy price. During declared stage emergencies the cap is determined by calculating the marginal cost of the highest priced unit dispatched. During non-emergency hours, the cap is set at 85 percent of the highest hourly ex-post price calculated during the last full hour of ISO operation under a Stage 1 emergency (which was $108.08/MWh and occurred in hour ending 10:00 on May 31, 2001). The cap remained unchanged throughout July because the ISO did not operate under a Stage 1 emergency for a full hour during the month. The cap will be reset upon the next full hour of a Stage 1 emergency. Bids accepted above the cap are paid as bid subject to cost justification.[3]

  The as-bid structure of the market and out-of-market purchases have created several prices and volumes related to the real time market. The BEEP market now consists of several components displayed in numbered columns: the market clearing price (MCP) and quantity for bids under the price cap (1), the as-bid price and volume for bids accepted over the price cap (2), and the Out-of-market purchases in real-time (4). The combination of these components yields the total "effective real time price" in column 5. The vast majority of the OOM costs in column 4 are comprised of CERS purchases on behalf of the IOU's in real-time. The averages for each of these different segments of total real time purchases for peak, off-peak, and all hours are reported below in the numbered columns:

Table 1: Real Time Energy Price Summary for July 2001*

	Market Clearing Avg. Price and Total Volume (1)	As-bid Avg. Price and Total Volume (2)	Total BEEP* Avg. Price and Total Volume (3)	Out-of-market Avg. Price and Total Volume (4)	"Effective Real Time Avg. Price" and Total Volume (5)	Average System Loads and Percent Under-scheduling
Peak	$47.62 (30 GWh)	$107.83 (8 GWh)	$54.35 (37 GWh)	$71.24 (509 GWh)	$67.29 (547 GWh)	30,664 MW 2.7%
Off-peak	$42.03 (43 GWh)	$100.73 (1 GWh)	$42.69 (44 GWh)	$56.17 (-4 GWh)	$51.59 (41 GWh)	23,253 MW -0.6%
All Hours	$45.34 (73 GWh)	$107.42 (9 GWh)	$49.90 (82 GWh)	$67.20 (506 GWh)	$62.61 (587 GWh)	28,193 MW 1.8%

[2] FERC ordered a 10 percent adder to the market-clearing price for generators selling into the ISO markets to account for increased credit risk.
[3] Accepted bids in the California ISO market above the price cap are not paid the additional 10 percent credit risk premium adder.

* The values in this table represent the average prices of all transactions and should not be used to value total transactions which occur at separate INC and DEC prices. The values in this table do not include the 10 percent risk premium adder that is paid to all sellers receiving the market-clearing price.

Note: Dollar figures are $/MWh and % represents percent underscheduling. The above dollar values are the average prices per MWh transacted in real-time and do not represent the average cost of electricity. For reference, the average cost of electricity and ancillary services for the entire system (including UDC generation at cost, bilateral transactions at hub prices, and real time costs) for the month of July is estimated at $73/MWh.

- Average real time prices decreased 40% in July compared to June. Total loads in July increased from June while average hourly underscheduling increased only slightly as a percent of load from 1.6% to 1.8%. Contributing to the monthly price differences in real time prices was a decrease in the average spot price for natural gas from $5.28/MMBtu in June to $3.99/MMBtu in July.[4]

II. Ancillary Service Markets

Ancillary Service Prices

- The five ancillary services are procured through a day-ahead and an hour-ahead market to meet reserve requirements. Effective June 20, 2001 (for operating day June 21), the FERC's June 19, 2001 Order went into effect, which the ISO is interpreting to cap ancillary service prices at the effective real time cap during all hours. Reserve requirements that are not met at prices at or below the soft cap are purchased at the bid price and are subject to just and reasonable cost review. Beginning December 31, 2000, capacity payments for Replacement Reserve are rescinded to the extent that Replacement Reserve energy is dispatched from the corresponding resource in real- time. The resulting savings have ranged from $10 million to $20 million per month.

- The California investor-owned utilities continued to self provide a portion of their A/S requirements. The volume reported in Table 2 includes the IOU's self-provision of A/S.

- Average prices for ancillary services were down significantly in July compared to June 2001. Regulation Up prices decreased by 48% while Regulation Down prices decreased by 55%. Prices for Spinning Reserve decreased by 78% while prices for Non-Spinning Reserve fell by 57%. Replacement Reserve prices decreased by 82%. Between 67% and 99% of requirements were purchased in the day-ahead market. Table 2 below summarizes the weighted average prices and quantity procured for July 2001 in both the day-ahead and hour-ahead markets.

- Table 3 compares the weighted average A/S prices in the day-ahead market during peak and off-peak periods along with the percentage of hours during which ancillary services were procured zonally (day-ahead and hour-ahead combined) for July 2001.

[4] Average spot price for natural gas is equal to the average of PG&E Citygate and Southern California Border prices.

Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – July 2001*

	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	$ 57	$ 62	$ 57	448	69	87%
Regulation Down	$ 31	$ 41	$ 33	474	84	85%
Spin	$ 13	$ 17	$ 13	816	60	93%
Non-Spin	$ 18	$ 17	$ 18	1630	10	99%
Replacement	$ 17	$ 11	$ 15	75	37	67%

Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – July 2001*

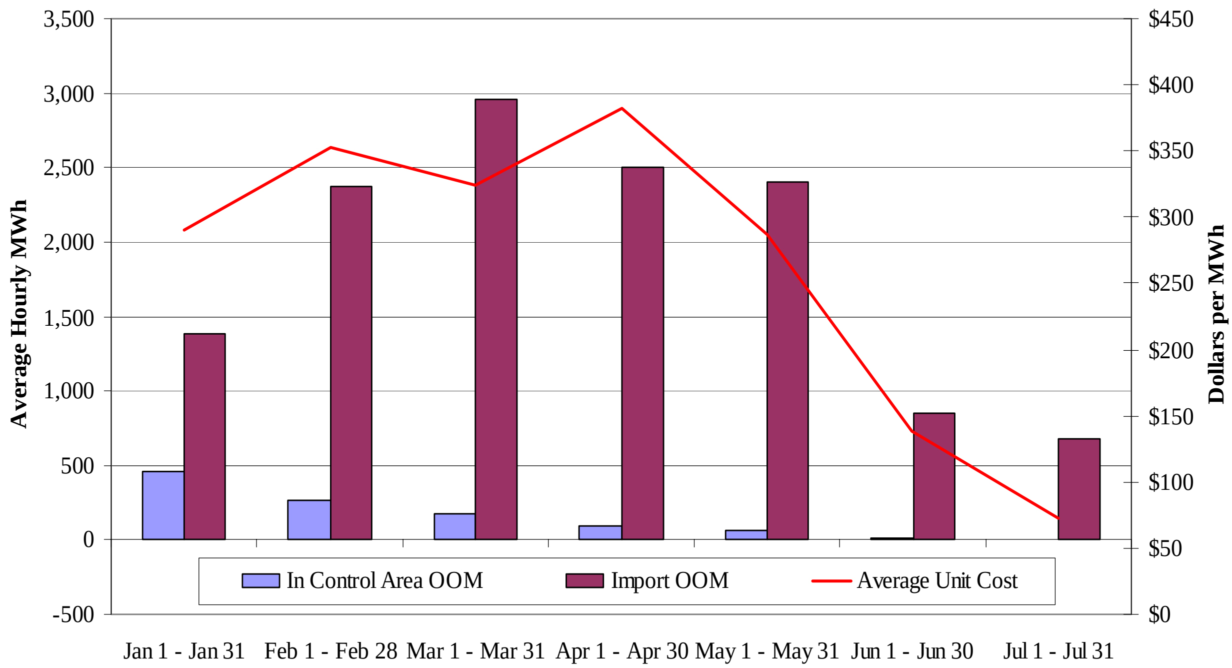
	NP15		SP15		Percent of Hours with Zonal Procurement
	Peak	Off Peak	Peak	Off Peak	
Regulation Up	$ 54	$ 45	$ 68	$ 58	0%
Regulation Down	$ 20	$ 43	$ 29	$ 59	0%
Spin	$ 13	$ 0	$ 47	$ 2	0%
Non-Spin	$ 27	$ 3	$ 25	$ 4	0%
Replacement	$ 14	$ 0	$ 65	$ 6	0%

*****Values in Table 2 and Table 3 do not include the 10 percent risk premium adder paid to all sellers receiving the market clearing price. Different prices in NP15 and SP15 are a result of quantity weighting of identical prices, not zonal procurement due to congestion.

III. Out of Market Calls (OOM)

The average out-of-market costs for July were $73/MWh, down $65/MWh compared with the June average of $138/MWh. On an hourly average basis, 680 MW were purchased out of market in July, with 100% of the OOM electricity coming from imports in the month. The total cost of out-of-market purchases in July was $36.7 million.

Figure 1. Quantities of Out-of-market Purchases (Average Hourly)
January 2001 - July 2001



IV. Summary of Market Costs

The total cost of energy and ancillary services in July was approximately $1.5 billion, decreasing from $1.9 billion in June. This is the second consecutive month in which the total costs of energy and ancillary services was lower than that of the same month in 2000. The average cost of energy and A/S decreased from $96/MWh in June to $75/MWh in July. Energy and A/S costs continue to be higher than those seen in the first two years of operation. Total energy and A/S costs for the first nine months of ISO operation in 1998 were approximately $5.55 billion resulting in an average cost of $33/MWh. Total costs in 1999 were comparable to 1998 with a total cost of approximately $7.43 billion (for twelve months) and an average cost of energy and A/S remaining steady at $33/MWh. Costs increased substantially in 2000. Total costs for energy and A/S in 2000 were over $27 billion, resulting in an average cost of $114/MWh. In 2001, through July, total energy and A/S costs are more than $21.7 billion with an average cost of $166/MWh of load served. This represents a significant cost increase over the first seven months in 2000 were through July energy and A/S costs totaled approximately $9.7 billion. However, this increase is due to the extraordinary costs seen in January through May 2001. The table on the next page provides a summary of Energy and A/S costs. The costs estimated in this table include estimates for utility-owned generation, CERS purchases, and bilateral transactions in the ISO control area.

Table 4
Summary of Energy and Ancillary Services Costs

A. Cost Summary through December 2000:

	ISO Load (GWh)	Est PX Energy Costs (MM$)*	Bilateral Energy Costs (MM$)*	RT Energy Costs (MM$)**	AS Costs (MM$)***	Total Energy Costs (MM$)	Costs of AS+ Energy (MM$)	Avg Energy Cost ($/MWh)	A/S Cost ($/MWh Load)	A/S Costs as % of Energy Costs	Total Costs ($/MWh load)
1998 (9mo)	169,239	$ 4,148	$ 556	$ 209	$ 638	$ 4,913	$ 5,551				
Avg 1998	18,804	$ 461	$ 62	$ 23	$ 71	$ 546	$ 617	$ 29	$ 3.77	13.0%	$ 33
Total 1999	227,533	$ 5,866	$ 982	$ 180	$ 404	$ 7,028	$ 7,432				
Avg 1999	18,961	$ 489	$ 82	$ 15	$ 34	$ 586	$ 619	$ 31	$ 1.78	5.7%	$ 33
Jan-00	18,984	$ 495	$ 103	$ 3	$ 12	$ 601	$ 612	$ 32	$ 0.62	2.0%	$ 32
Feb-00	17,807	$ 419	$ 103	$ 20	$ 10	$ 542	$ 552	$ 30	$ 0.58	1.9%	$ 31
Mar-00	18,989	$ 432	$ 90	$ 39	$ 11	$ 561	$ 572	$ 30	$ 0.60	2.0%	$ 30
Apr-00	18,212	$ 429	$ 101	$ 31	$ 17	$ 561	$ 578	$ 31	$ 0.95	3.1%	$ 32
May-00	19,997	$ 828	$ 225	$ 108	$ 63	$ 1,161	$ 1,224	$ 58	$ 3.16	5.4%	$ 61
Jun-00	21,605	$ 2,303	$ 529	$ 339	$ 436	$ 3,171	$ 3,607	$ 147	$20.19	13.8%	$ 167
Jul-00	21,935	$ 1,896	$ 346	$ 216	$ 125	$ 2,458	$ 2,583	$ 112	$ 5.71	5.1%	$ 118
Aug-00	23,141	$ 2,786	$ 585	$ 515	$ 282	$ 3,886	$ 4,168	$ 168	$12.18	7.3%	$ 180
Sep-00	20,620	$ 1,819	$ 389	$ 236	$ 152	$ 2,445	$ 2,597	$ 119	$ 7.39	6.2%	$ 126
Oct-00	18,184	$ 1,400	$ 356	$ 27	$ 56	$ 1,388	$ 1,434	$ 100	$ 3.33	3.3%	$ 104
Nov-00	18,656	$ 2,292	$ 402	$ 195	$ 114	$ 2,889	$ 3,004	$ 155	$ 6.13	4.0%	$ 161
Dec-00	19,412	$ 3,742	$ 820	$ 1,149	$ 440	$ 5,711	$ 6,151	$ 294	$22.65	7.7%	$ 317
Total 2000	237,543	$ 18,842	$ 4,048	$ 2,877	$ 1,720	$25,373	$27,083				
Avg 2000	19,795	$ 1,570	$ 337	$ 240	$ 143	$ 2,114	$ 2,257	$ 107	$ 7.24	6.8%	$ 114

* 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.
*** AS costs include self-provided quantities.

B. Cost Summary Since January 2001:

	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-01	18,770	16,950	$ 2,710	$ 756	$ 247	$ 3,466	$ 3,713	$ 185	$13.15	7.1%	$ 198
Feb-01	16,503	14,876	$ 2,657	$ 917	$ 198	$ 3,574	$ 3,772	$ 217	$12.00	5.5%	$ 229
Mar-01	17,857	16,744	$ 2,736	$ 881	$ 181	$ 3,616	$ 3,797	$ 203	$10.14	5.0%	$ 213
Apr-01	17,237	16,267	$ 2,537	$ 755	$ 178	$ 3,292	$ 3,471	$ 191	$10.34	5.4%	$ 201
May-01	19,651	18,351	$ 2,771	$ 601	$ 176	$ 3,372	$ 3,548	$ 172	$ 8.97	5.2%	$ 181
Jun-01	19,777	19,468	$ 1,598	$ 111	$ 187	$ 1,709	$ 1,896	$ 86	$ 9.48	11.0%	$ 96
Jul-01	20,976	20,599	$ 1,458	$ 54	$ 71	$ 1,513	$ 1,583	$ 72	$ 3.37	4.7%	$ 75
Total 2001	130,771	123,255	$16,468	$ 4,074	$ 1,238	$20,542	$21,781				
Avg 2001	$ 18,682	17,608	$ 2,353	$ 582	$ 177	$ 2,935	$ 3,112	$ 161	$ 9.63	6.3%	$ 167

***** 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

IV. Inter-zonal Congestion Management Markets

Very little inter-zonal congestion occurred in July. Congestion was limited primarily on Path 15 in the south to north direction and hour-ahead market exports on Victorville with occasional congestion on imports from Eldorado and exports on NOB. Total congestion costs for July increased to approximately $0.9 million from $0.6 million in June. Victorville hour-ahead congestion accounted for $0.4 million of the total congestion costs in June.

The following table summarizes the congestion rates and average congestion charges by branch group for the day-ahead market for July.

Table 5

Day-Ahead Market – Congestion Summary for June 2001

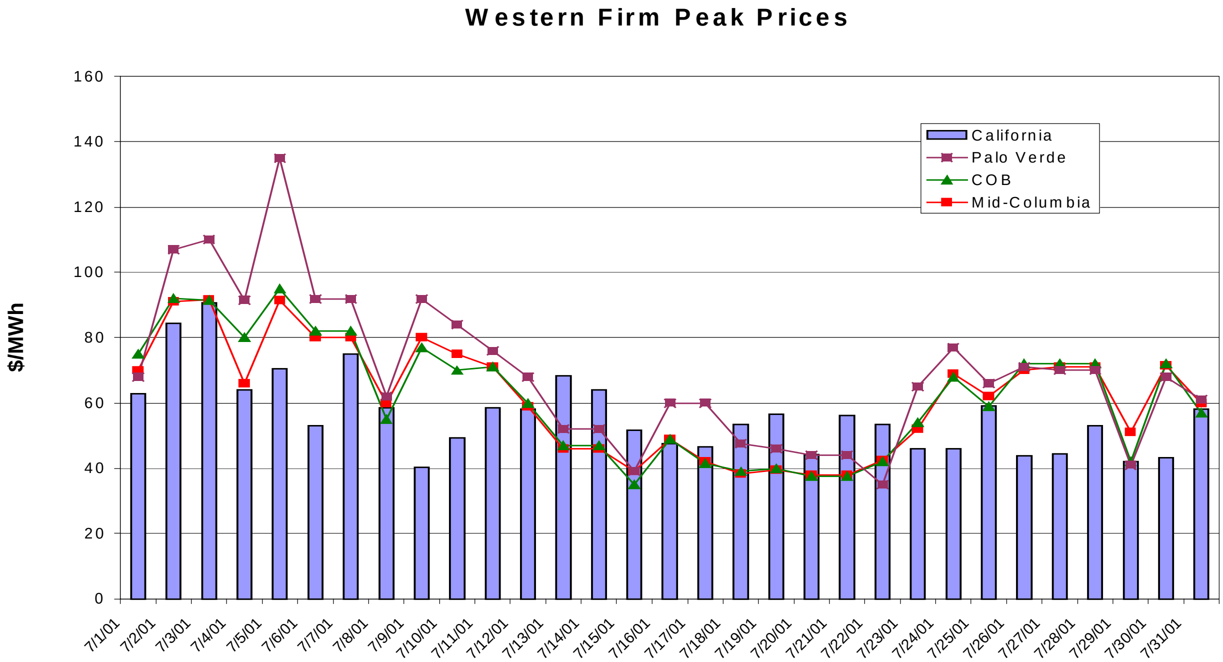
	Percentage Congestion by Period			**Average Congestion Charges ($/MW)**		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
NOB (Export)	0.6%	6.5%	2.6%	$30	$30	$30
Path 15 (S-N)	1.6%	5.7%	3.0%	$11	$0	$4

V. Western Regional Market Prices

Western Regional Spot Market Prices

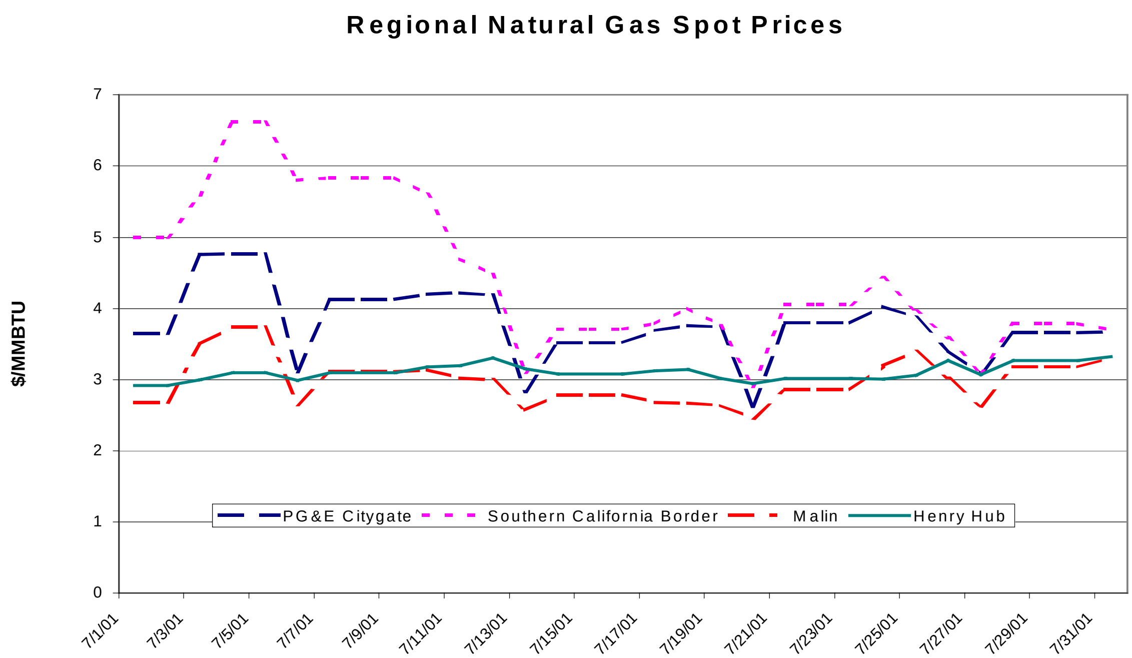
Western peak power prices continued to decline with some volatility through July as low gas prices continued to be present throughout the region. Western spot electricity prices rose in early July as hot weather across the region increased cooling demand. Spot prices in the Southwest, where temperatures were the highest, exceeded the $91.87/MWh price cap set after the last ISO stage one emergency. Prices exceeded the cap in the Southwest because buyers were apparently willing to pay above-cap prices to secure day-ahead power to serve cooling demand in the region. Prices in the Northwest also rose in early July by $14/MWh due to rising weather-related demand where temperatures in cities such as Portland were expected to surpass 90 degrees. As hot weather continued through the first week of July, peak power prices traded narrowly around the FERC price cap of $91.87/MWh, though the Southwest continued to see prices in excess of the cap.

Prices dropped significantly through mid July as milder weather reduced cooling related demand. In addition, an increase in the amount of exports from the Northwest also put downward pressure on prices. Western peak power prices were higher starting the third week of July due to forecasted hot weather in the region. Prices soon declined as weather related demand tapered off and more than 1,000 MW of generation returned from outages in the ISO control area.



California Natural Gas Prices

California natural gas prices continued to drop in July for all of the major trading hubs. The decrease in prices was due to milder weather conditions leading to less cooling demand combined with increased generation availability of nuclear and hydro generation resources reducing demand for gas fueled generation. Hot weather in much of California and the West caused Southern California Border prices to increase to around $6.50/mmbtu on July 5. However, as milder weather conditions prevailed, Southern California Border prices decreased significantly in early July to levels near the other regional trading hubs. Prices fluctuated between $3 and $4/mmbtu during the last two weeks in July. The low gas prices continued into bidweek resulting in August bidweek prices of $3.76, $3.22, and $3.14 for SoCalGas, PG&E, and Malin respectively.



VI. Performance of the Firm Transmission Rights Market in July 2001

FTR Concentration

There was only one secondary FTR market trade in July 2001, namely, a transfer of 35 MWs (7x24 hours for the period July 24-September 30, 2001) on COI (Import direction) from Mirant (SCEM) to Trans-Alta (TRAL). The following table shows FTR ownership concentration above at or above 25% on different paths (Branch Group and Direction) as of the end of July 2001.

FTR Ownership Concentration above 25% as of July 31, 2001

Branch Group	Dir.	Owner ID	Owner Name	Max FTRs Owned	Hours Max FTR Owned	Total FTRs Auctioned	% Conc.
SILVERPK	IMP	SCE1	Southern California Edison Company	10	5,857	10	100.0
SILVERPK	EXP	IPC1	Idaho Power Company	10	5,113	10	100.0
SILVERPK	EXP	IDAC	IdaCorp Energy	10	744	10	100.0
ELDORADO	IMP	SCE1	Southern California Edison Company	582	5,857	707	82.3
IID-SCE	IMP	SCE1	Southern California Edison Company	460	5,857	600	76.7
NOB	EXP	VERN	City of Vernon	82	5,857	111	73.9
ELDORADO	EXP	IPC1	Idaho Power Company	401	5,113	626	64.1
ELDORADO	EXP	IDAC	IdaCorp Energy	401	744	626	64.1
COI	EXP	SCEM	Southern Company Energy Marketing, L.P.	33	5,857	56	58.9
VICTVL	EXP	IDAC	IdaCorp Energy	166	744	296	56.1
VICTVL	EXP	IPC1	Idaho Power Company	166	5,113	296	56.1
PATH26	IMP	SCEM	Southern Company Energy Marketing, L.P.	100	5,857	199	50.3
CFE	EXP	PETP	Pacific Gas and Electric Company	200	5,857	408	49.0
PALOVRDE	EXP	WESC	Williams Energy Services Corporation	381	5,857	796	47.9
NOB	IMP	SCE1	Southern California Edison Company	250	5,857	523	47.8
MEAD	EXP	IPC1	Idaho Power Company	213	5,113	456	46.7
MEAD	EXP	IDAC	IdaCorp Energy	213	744	456	46.7
CFE	IMP	MSCG	Morgan Stanley Capital Group, Inc.	171	5,857	408	41.9
COI	EXP	IDAC	IdaCorp Energy	23	744	56	41.1
COI	EXP	IPC1	Idaho Power Company	23	5,113	56	41.1
PATH26	IMP	NEI1	NewEnergy Inc.	74	5,857	199	37.2
COI	IMP	IPC1	Idaho Power Company	219	5,113	600	36.5
COI	IMP	IDAC	IdaCorp Energy	219	744	600	36.5
PATH26	EXP	SCE1	Southern California Edison Company	575	5,857	1,727	33.3
PALOVRDE	IMP	SCE1	Southern California Edison Company	602	5,857	1,819	33.1
VICTVL	IMP	MSCG	Morgan Stanley Capital Group, Inc.	316	5,857	1,013	31.2
VICTVL	IMP	SCEM	Southern Company Energy Marketing, L.P.	314	5,857	1,013	31.0
PATH26	EXP	PETP	Pacific Gas and Electric Company	500	5,857	1,727	29.0
PATH26	EXP	SCEM	Southern Company Energy Marketing, L.P.	477	5,857	1,727	27.6
PALOVRDE	IMP	WESC	Williams Energy Services Corporation	500	5,857	1,819	27.5
MEAD	EXP	SCEM	Southern Company Energy Marketing, L.P.	125	5,857	456	27.4
CFE	EXP	IPC1	Idaho Power Company	106	5,113	408	26.0
CFE	EXP	IDAC	IdaCorp Energy	106	744	408	26.0
MEAD	IMP	SCEM	Southern Company Energy Marketing, L.P.	125	5,857	487	25.7
VICTVL	EXP	VERN	City of Vernon	75	5,857	296	25.3
PALOVRDE	EXP	IPC1	Idaho Power Company	200	5,113	796	25.1
PALOVRDE	EXP	IDAC	IdaCorp Energy	200	744	796	25.1
CFE	EXP	MSCG	Morgan Stanley Capital Group, Inc.	102	5,857	408	25.0

NOTES:

- The **Hours Max FTR Owned** shows the number of hours from the reporting date (July 31, 01) through the end of the FTR auction cycle (March 31, 02) during which the reported FTR concentration persists.
- For Path 26 the IMP direction is South to North and the EXP direction is North to South
- On July 30, 200, Idaho Power (IPC1) transferred a portion of its FTRs to its affiliate IdaCorp Energy (IDAL) for the month of August 2001. Both are reported in the table.

FTR Scheduling

On most paths the FTRs have been primarily used for their financial entitlement to hedge against transmission usage charges. The relative volume of schedules with FTR priority attached for the period July 1-31, 2001 on all paths amounted to only 21% of the total available FTR volume, although on some paths the percentage was quite high (e.g., 97% on Silverpeak and 78% on Eldorado in the Import direction). The following table shows the paths on which FTRs were attached to schedules, along with related statistics for July 2001. Regarding specific paths with significant changes in FTR ownership concentration reported in previous Market Analysis Reports, namely, NOB (export direction) and Victorville (export direction), the FTR scheduling in July 2001 was on the average insignificant to moderate. On some paths (Silverpeak, Eldorado, and IID-SCE) both the FTR ownership concentration and scheduling are quite high. However, the magnitude and frequency of congestion on these paths were not significant enough in July to raise market power concerns.

FTR Scheduling Statistics in July 2001

Branch Group	COI IMP	ELD IMP	IID-SCE IMP	PV IMP	SilvPk IMP	COI EXP	ELD EXP	MEAD EXP	NOB EXP	PV EXP	P26 EXP	VictVl EXP
MW FTR Auctioned	600	707	600	1,819	10	56	626	456	111	796	1,727	296
Avg. MW FTR Scheduled	27	561	423	582	9.7	3	44	183	1.2	253	93	10
% FTR Scheduled	5%	79%	71%	32%	97%	5%	7%	40%	1%	32%	5%	3.5%
Max MW FTR Scheduled	126	607	443	785	10	48	175	338	25	555	575	149
Max Single SC FTR Schedule	101	582	443	600	10	25	175	213	25	381	575	149

VII. Issues Under Review and Analysis

FERC Refund Hearings

DMA staff continues to perform extensive analyses in response to FERC's July 25 Order on refunds in California's wholesale energy market. The DMA collaborated with Market Operations staff in calculating an hourly "Mitigated Market Clearing Price" based on the heat rates of gas-fired units dispatched in the ISO's imbalance energy market, pursuant guidelines provided in the July 25 Order. DMA staff is also developing settlement quality documentation of sales in the ISO real time energy and ancillary service market based on data the Settlements database. This "Mitigated Market Clearing Price" and transaction data are to be used in determining refund obligations of suppliers under the July 25 Order. Additional details of this process and calculation of refunds are the subject of a FERC hearing set for September.

The July 25 Order includes a number of features that significantly limit refunds, and would result in lower refunds than would result from previous analyses performed by DMA. Key limitations in the July 25 Order include: (1) the exclusion of purchases prior to October 2, 2000; (2) exclusion of purchases by CDWR on behalf of the state's UDCs' starting in January 2001; (3) use of a 10% "risk premium" after January 5, 2001; (4) use of spot market gas prices rather than actual gas costs or monthly contract prices; and (5) use of the highest heat rate of any units dispatched, rather than the highest heat rate of any unit that would have been needed to meet demand in the absence of economic withholding (i.e. bidding significantly in excess of costs) and physical withholding (not bidding all available capacity) in the real time market.

PG&E Bankruptcy

Extensive data requests are being issued to the ISO from participants in the PG&E Bankruptcy proceedings who are seeking to acquire confidential scheduling and bidding data, as well as confidential analyses related to high prices performed by DMA over the last year. DMA has submitted an affidavit to the bankruptcy Court recommending that access to such confidential data be limited, on the grounds that wide distribution of these data to individuals engaged in market operations may have anti-competitive market impacts. This issue is currently pending before the Bankruptcy court.

Monitoring and Reporting of Anti-Competitive Bidding Practices

DMA is currently submitting reports to FERC on a confidential basis pursuant the FERC's April 26 Order. The reports provide indices, analysis and data on scheduling, outage and bidding practices, and identify any concerns about possible inappropriate bidding behavior.

DMA also submitted a special filing to FERC alerting the Commission to the fact that only one market participant has submitted justification to the ISO for real time energy sales made over the mitigated price limits in effect during system emergencies from May through June 2. Under the Commission's, April 26 Order, participants were required to submit justification for any bids accepted over the price cap to both the ISO and FERC. The ISO has filed a tariff change so that participants would not be eligible to receive payment for any bids over the mitigated price that are accepted unless they submitted cost justification.

Investigation of Market Power and Potential Price Manipulation

DMA continues to collaborate with a variety of state and federal agencies conducting confidential investigations of potential market power abuses and price manipulation. In particular, the DMA is setting up a process to track the "must offer" compliance on a portfolio basis for affiliated groups of market participants.