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 August 2001

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

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

EXECUTIVE SUMMARY

Real time electricity and ancillary service prices decreased in August compared to July due to high generation availability, seasonable temperatures, and continuing decreasing natural gas prices. On average, the price of real time electricity in August decreased 27% to $46/MWh from the July average of $63/MWh. Although loads increased slightly in August compared to July as warmer temperatures increased cooling demand, loads declined from August 2000 levels showing visible conservation efforts. Total load in August was down 6.3% from August of last year. The California Energy Commission (CEC) provides refined estimates of conservation after normalizing for growth and weather conditions. In August, the CEC calculated that the growth and weather normalized demand for monthly energy dropped by 7.1 percent from August 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]. Under FERC's June 19 mitigation formula, prices were initially capped 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 August 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 can be submitted and accepted above the cap, and are paid as bid subject to cost justification.[2]

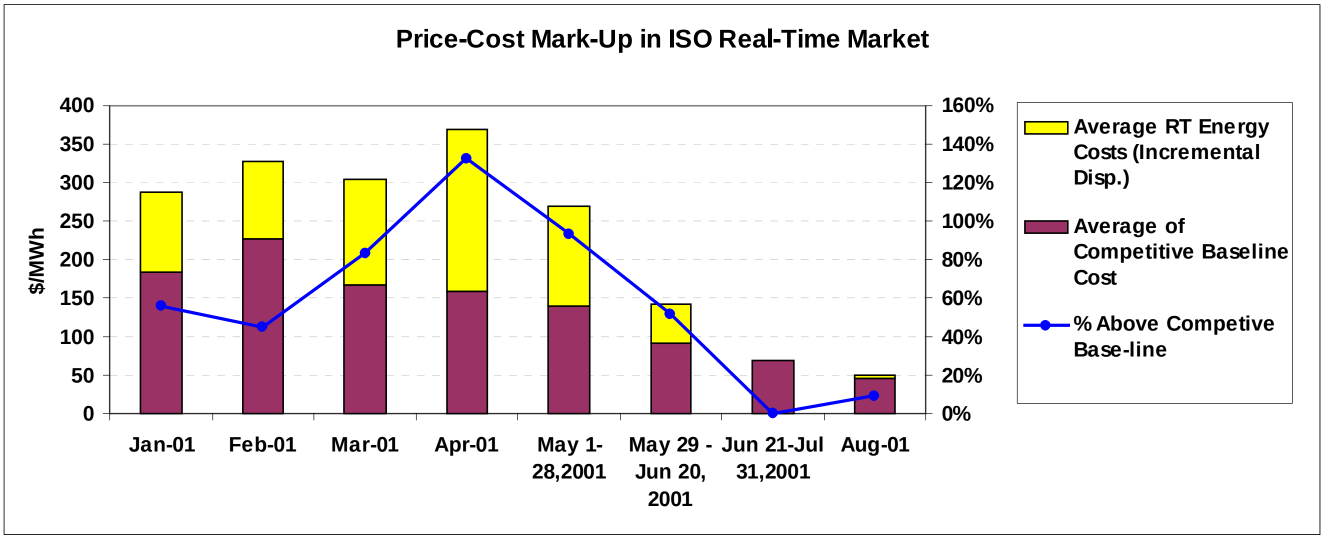
A preliminary review shows that the FERC's June 19 Order has been somewhat effective in mitigating real time prices. Figure 1 shows the reduction in the real-time price was due in part to the reduction in production costs as well as the reduction in the mark-up suppliers charged over costs. In August, there was a slight increase in markup from July to 9 percent above the competitive benchmark cost. In addition,

[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.

[2] FERC, in a Sept. 7 notice, ordered Reliant Energy Services, Williams Energy Services Corporation, and Mirant Americas Energy Marketing to refund an undisclosed dollar amount to California electricity buyers during the last week of June. FERC stated that all three companies did not adequately justify reasons for selling energy over the mitigated ISO clearing price in the first week after the June 20th order took effect.

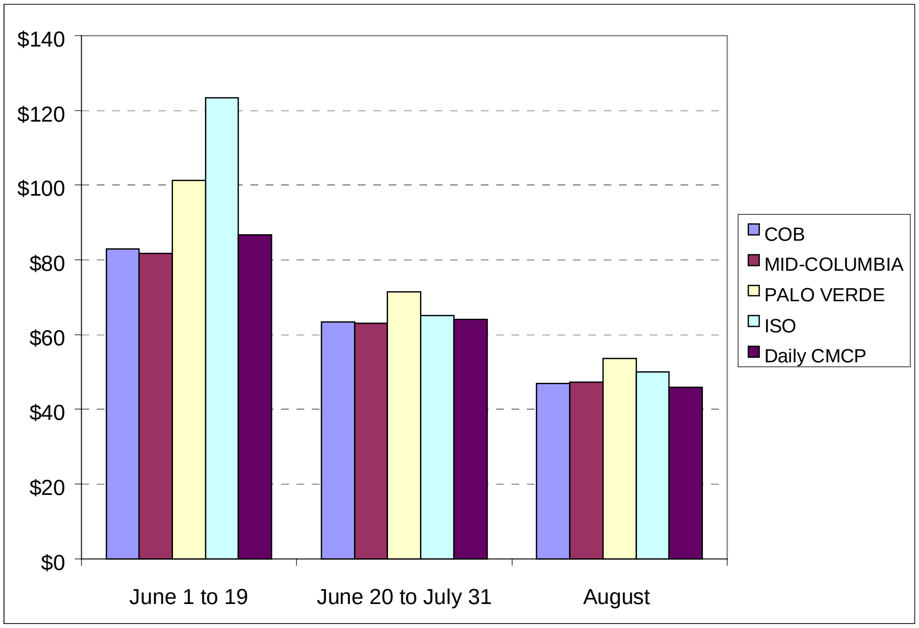
high bids continue to be submitted in the real-time market which could cause an increase in the measure of mark-up suppliers charged over costs in the event that demand rises to levels where the ISO is forced to accept these bids.

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 the California competitive baseline cost. In August, as well as for the period of June 20 to July, all average regional prices were close to or slightly above the California competitive baseline cost. In contrast, ISO real-time price and Palo Verde price were significantly above the benchmark price in early June. 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 California Competitive Baseline



Other key market activities include the following:

- **Regional spot electricity prices decreased in August from July**. Low natural gas prices and increased generation availability put continued downward pressure on prices. Overall, regional prices reported in the Northwest were 8.6% lower than "effective real time energy prices" in NP15, while regional prices reported in the Southwest were 4.7% higher 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 $3.99/MMBtu in July to $3.27/MMBtu in August**. 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 relatively mild temperatures and more than adequate supplies.

- **Underscheduling of loads 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 0.5 percent in August. There appeared to be instances of overscheduling of resources in many hours in August.

- **Lower Ancillary Service Costs.** In August, ancillary service prices decreased compared to July as ancillary service costs decreased by 30%. Total ancillary service costs were $50 million in August, down from the July total of $71 million, representing a decrease from $3.37 to $2.38 per MWh of load served.

- **Low Congestion Costs.** Day-ahead congestion in August was primarily limited to imports on COI with small amounts of export congestion on Mead, Victorville and South to North on Path 15. Total congestion costs for August increased to approximately $2.7 million from $0.9 million in July.

KEY MARKET CONDITIONS FOR AUGUST 2001

I. California Wholesale Energy Markets

- **Loads.** Monthly system energy consumption for August totaled 21,689 GWh, a 6.3% decrease from August 2000, reflecting significant conservation efforts by California consumers. The peak load for the month reached 41,115 MW, a 5.5% decrease from the August 2000 peak of 43,509 MW. Daily peak loads averaged 35,809 MW, a 7.4% decrease from August 2000. The California Energy Commission provides estimates of conservation after normalizing for growth and weather conditions. In August, the CEC calculated that monthly peak demand for electricity dropped by 8.9 percent from August 2000 and monthly energy dropped by 7.1 percent on a growth and weather normalized basis.

- **Wholesale Energy Prices.** On June 20, the FERC's West-wide price mitigation Order 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.[3]. 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 and August because the ISO did not operate under a Stage 1 emergency for a full hour during either 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.[4]

  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 scheduled 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 August 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	$26.25 (-61 GWh)	$102.81 (1 GWh)	$26.49 (-60 GWh)	$55.90 (378 GWh)	$47.61 (318 GWh)	32,061 MW 1.7%
Off-peak	$35.88 (37 GWh)	$92.00 (0 GWh)	$35.88 (37 GWh)	$39.92 (-77 GWh)	$38.47 (-40 GWh)	23,335 MW -2.6%
All Hours	$29.28 (-24 GWh)	$102.81 (1 GWh)	$29.44 (-23 GWh)	$52.02 (301 GWh)	$45.19 (277 GWh)	28,291 MW 0.5%

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

[4] Accepted bids in the California ISO market above the price cap are not paid the additional 10 percent credit risk premium adder.

* Note for Table 1: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.

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 August is estimated at $65/MWh.

- Average real time prices decreased 27% in August compared to July. Total loads in August increased from July while average hourly underscheduling decreased as a percent of load from 1.8% to 0.5%. Contributing to the monthly price differences in real time prices was a decrease in the average spot price for natural gas from $3.99/MMBtu in July to $3.27/MMBtu in August.[5]

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 in August compared to July 2001. Both Regulation Up and Regulation Down prices decreased by approximately 21%. Prices for Spinning Reserve decreased by 8% while prices for Non-Spinning Reserve fell by 50%. Replacement Reserve prices decreased by 93%. Between 48% and 99% of requirements were purchased in the day-ahead market. Table 2 below summarizes the weighted average prices and quantity procured for August 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 August 2001.

[5] 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 – August 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	$ 46	$ 28	$ 45	534	12	98%
Regulation Down	$ 27	$ 7	$ 26	517	50	91%
Spin	$ 12	$ 7	$ 12	1413	10	99%
Non-Spin	$ 9	$ 4	$ 9	894	54	94%
Replacement	$ 2	$0.2	$ 1	40	44	48%

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

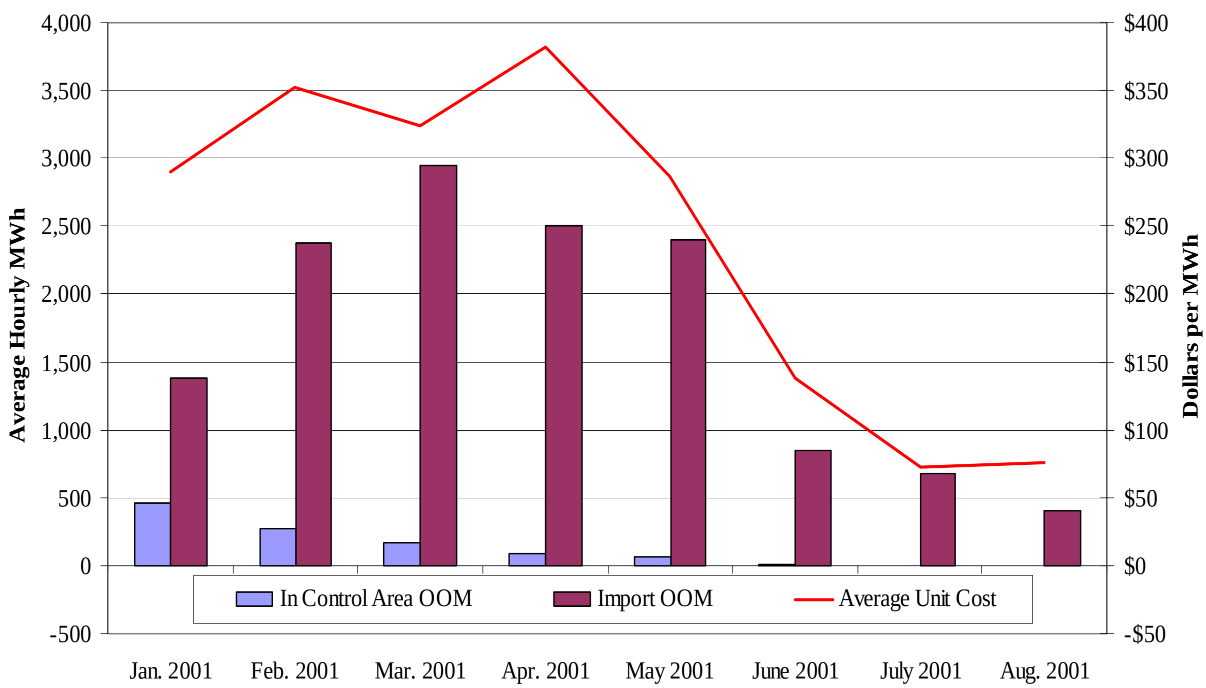
	NP15		SP15		Percent of Hours with
	Peak	Off Peak	Peak	Off Peak	Zonal Procurement
Regulation Up	$ 46	$ 41	$ 52	$ 43	0%
Regulation Down	$ 19	$ 38	$ 26	$ 41	0%
Spin	$ 18	$ 1	$ 17	$ 1	0%
Non-Spin	$ 8	$ .02	$ 26	$ .05	0%
Replacement	$ 1	$ .09	$ 13	$ 1	0%

*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) and BEEP Volumes

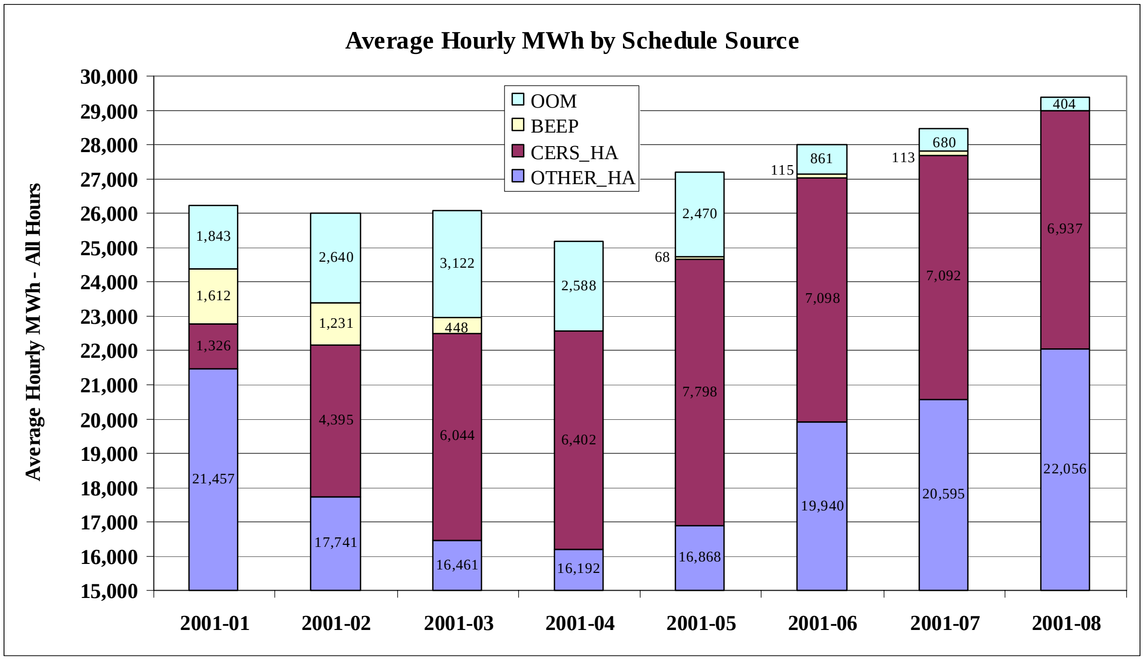
This summer has seen a dramatic decrease in net out-of-market volumes from an average of approximately 2,500 MWh/hr from February through May to 860 MWh/hr in June, 680 MWh/hr in July, and 400 MWh/hr in August (see Figure 3. below). There also has been a corresponding drop in the average price of out-of-market purchases from $380/MWh in April to $75/MWh in August (up $3/MWh compared with the July average of $73/MWh). On an hourly average basis, 405 MW were purchased out of market in August, with 100% of the OOM electricity coming from imports. The total cost of out-of-market purchases in August were $22.7 million.

Figure 3. Quantities of Out-of-market Purchases (Average Hourly)
January 2001 - August 2001



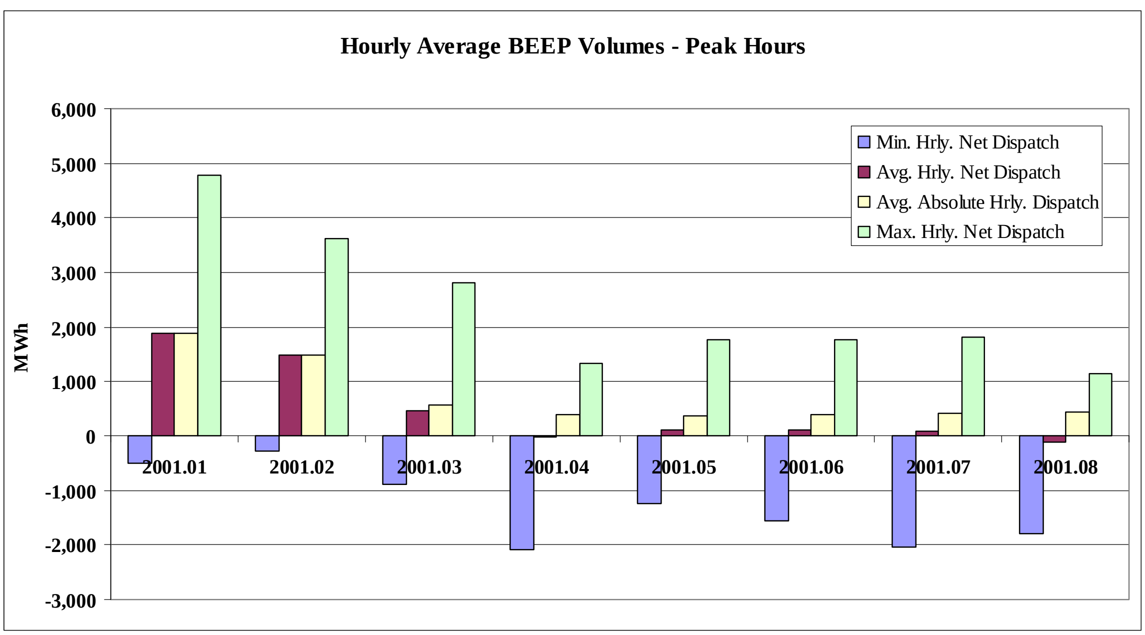
Forward schedules are covering greater levels of load requirements. This reduced reliance on the real-time market helps maintain competitive performance because suppliers are less likely to be pivotal in setting real-time prices. The chart below shows average hourly net volumes by scheduling source for each month of this calendar year. The decline in out-of-market volume has been accompanied by relatively flat forward purchases by CERS, an increase in forward scheduled volumes by other participants, and relatively small net BEEP volumes.

Figure 4. BEEP Volume: Increased forward scheduling has reduced the need for OOM and decreased volumes in the real-time market



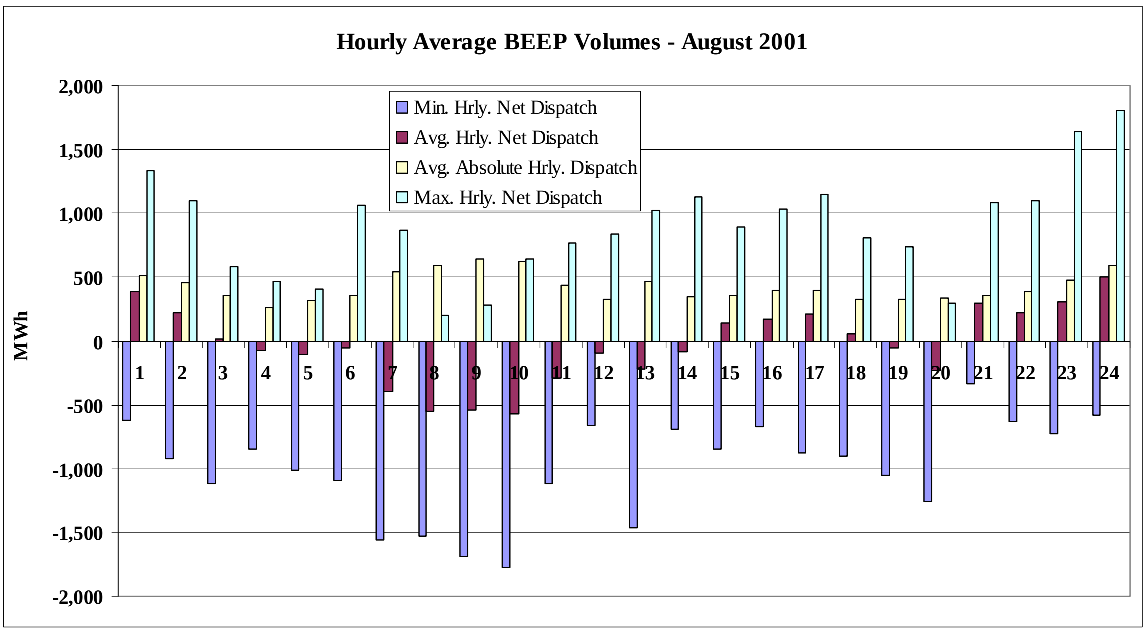
The chart below shows the average hourly net BEEP dispatch, average of the absolute value of net hourly BEEP dispatch, the minimum hourly net BEEP dispatch (net dec.), and the maximum hourly net BEEP dispatch (net inc.).

Figure 5. Range of BEEP Volumes



The role of the BEEP market is well represented by the minimum and maximum hourly net dispatches and the average of the absolute value of the hourly net dispatch (measuring hourly volume across the month). Although monthly average hourly net BEEP dispatches have declined since January, this chart show that on an hourly basis the BEEP dispatches are serving more of a role as an imbalance market rather than a source of energy supply. There were significant net incremental and net decremental dispatches in hours across the month. This can be seen via the minimum and maximum hourly net dispatches in the chart above. Average hourly volume, incremental or decremental, has remained fairly constant since March as seen in the average hourly absolute dispatch series above.

Figure 6. Hourly Profile of BEEP Dispatch



A review of the hourly profile of BEEP dispatch shows the recent trend has been to DEC resources because of a mismatch of load and supply during shoulder hours of the day. In the early shoulder peak hours the average net BEEP dispatch is negative. This represents significant net decremental dispatches during these hours throughout the month, with the largest net decremental dispatches occurring during these hours as well (the Min. Hrly. Net Dispatch series). One possible reason for this is that forward purchases do not coincide with load patterns observed throughout the day. Another concern in the real time market is that there continues to be large uninstructed deviations by suppliers from schedules which causes reliability concerns. We are examining possible tariff changes that would apply penalties to suppliers for these large deviations from schedules.

IV. Summary of Market Costs

The total cost of energy and ancillary services in August was approximately $1.4 billion, decreasing from $1.6 billion in July. This is the third consecutive month in which the total costs of energy and ancillary services were lower that that of the same month in 2000. The average cost of energy and A/S decreased from $75/MWh in July to $65/MWh in August. 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 ten 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 $7.03 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 August, total energy and A/S costs are more than $23.1 billion with an average cost of $157/MWh of load served. This represents a significant cost increase over the first eight months in 2000 where through July, energy and A/S costs totaled approximately $13.9 billion. However, this increase is due to the extraordinary costs seen in January through May 2001, with the trend reversing in June. Table 4 on the next page provides a summary of Energy and A/S costs. The costs estimated in is this table include estimates for utility 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
Aug-01	21,689	21,571	$ 1,329	$ 34	$ 50	$ 1,363	$ 1,414	$ 63	$ 2.31	3.7%	$ 65
Total 2001	152,460	144,826	$17,797	$ 4,109	$ 1,288	$21,906	$23,194				
Avg 2001	19,058	18,103	$ 2,225	$ 514	$ 161	$ 2,738	$ 2,899	$ 148	$ 8.72	6.0%	$ 157

***** 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

During August, congestion was limited primarily to imports on COI with small amounts of export congestion on Mead, Victorville and South to North on Path 15. Total congestion costs for August increased to approximately $2.7 million from $0.9 million in July. Import congestion on COI accounted for over $2.0 million of the total congestion costs in August.

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

Table 5

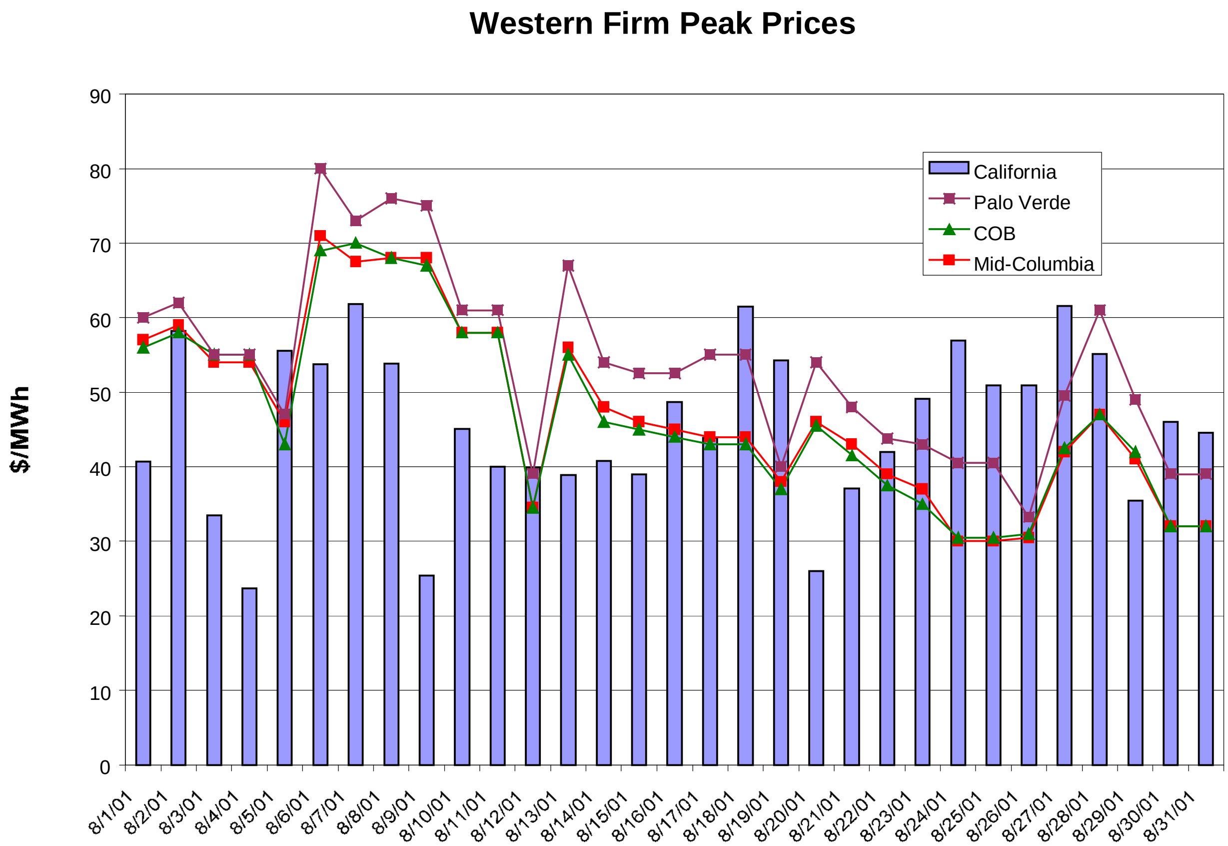
Day-Ahead Market – Congestion Summary for August 2001

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	**Off peak**	**All Hours**	**Peak**	**Off peak**	**All Hours**
COI (Import)	6.3%	0.4%	4.3%	$45	$30	$45
Mead (Export)	2.6%	0%	1.8%	$30		$30
Victorville (Export)	1.8%	0%	1.2%	$30		$30
Path 15 (S-N)	0.2%	8.5%	0.7%	$.02	$.02	$.02

V. Western Regional Market Prices

Western Regional Spot Market Prices

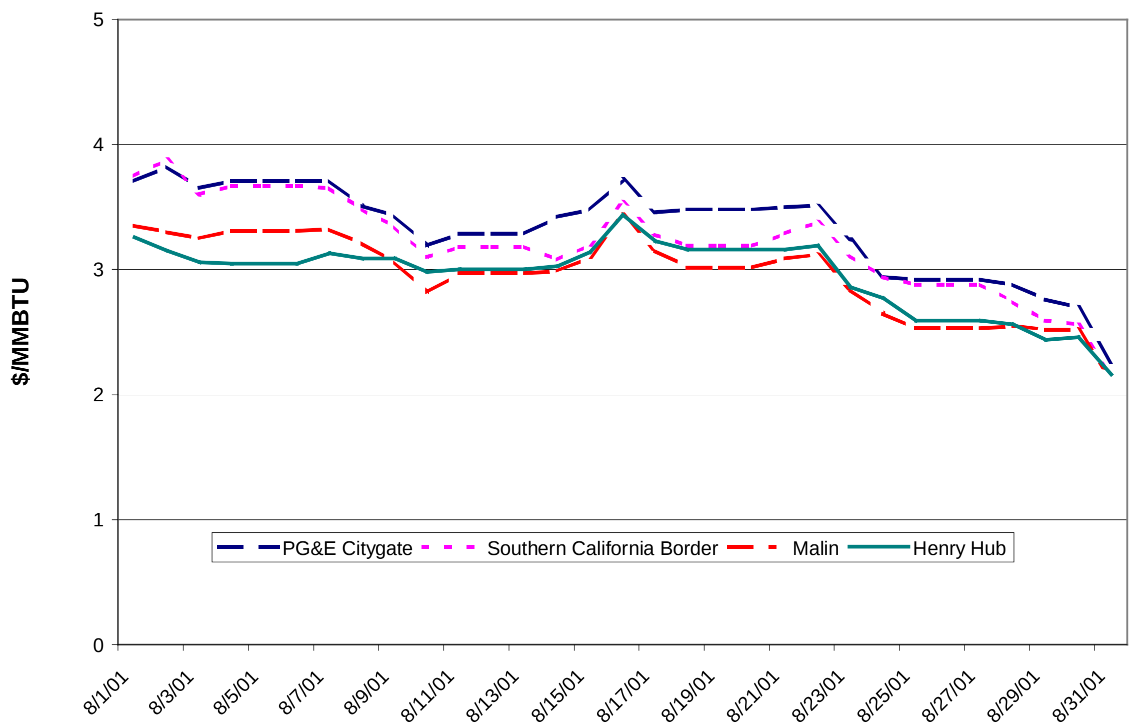
Western peak power prices continued to decline with some volatility through August as gas prices decreased throughout the region. Prices increased significantly on August 6th due to increased demand resulting from forecasted warmer temperatures in California and the Southwest. Peak power prices in California increased by over $20/MWh as demand increased in California and the Southwest. Peak heavy load prices in the Northwest increased by $17/MWh due to the increased demand. With the highest temperatures for the start of the month in the Southwest, Palo Verde prices were the highest in the West reaching $80/MWh. Prices fell between August 10th and 13th due to reduced demand from cooler weather throughout the West and a healthy Northwest generation picture. Generation was abundant throughout the WSCC, which dampened the effect of higher temperatures in the region during the third week of August. Prices continued to decrease through the rest of the month due to continued abundant generation, seasonable temperatures, and continuing decreasing gas prices. By the end of the month, natural gas prices throughout the West were near $2.00/mmbtu resulting in western peak power prices between $30 and $40/MWh.



California Natural Gas Prices

California spot natural gas prices continued to fall through August. Spot prices stabilized between $3.00 and $4.00/mmbtu through the first two weeks of the month. The basis differential between the Henry Hub and Southern California Border averaged $0.37/mmbtu, and $0.17/mmbtu between the Henry Hub and PG&E, which approached their historical averages prior to November 2000 of about $0.21 and $0.13/mmbtu respectively. Sufficient supplies and net working gas injections within the range of expectations combined to provide stability to natural gas prices despite high temperatures that prevailed throughout much of California. Prices increased temporarily on August 16 to $3.59 and $3.55/mmbtu at PG&E and Southern California Border respectively in response to a historically low mid-summer net storage injection estimate. Prices began to decline somewhat by the end of the week. With the return of above-average storage refill estimates for the third week of August and relatively widespread normal temperatures, prices moved down at the California markets. Prices continued downward through the end of the month spurred by relatively mild temperatures and more than adequate supplies. By the end of the month, both northern and southern California gas prices were at levels not seen since January 2000 at $2.12 and $2.16/mmbtu respectively. September bidweek prices were also lower compared to August with prices at SoCal Gas, Malin, and PG&E Citygate at $2.65, $2.44, and $2.70/mmbtu respectively. With moderate temperatures and sufficient supplies, prices are not expected to return to higher levels soon.

Regional Natural Gas Spot Prices



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

FTR Concentration

There were no secondary FTR market trades and no FTR SC reassignments in August 2001. Therefore there are no changes in FTR ownership concentrations compared to those reported in the July 2001 report.

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 August 1-31, 2001 on all paths amounted to 21% of the total available FTR volume (compared to 20% in July 2001), although on some paths the percentage was quite high (e.g., 97% on Silverpeak, 81% on Eldorado, and 68% on IID-SCE, all in the import direction). The following table shows the paths on which 1% or more of the FTRs were attached to schedules, along with the related statistics, for August 2001. Regarding specific paths with high FTR ownership concentration reported in previous Market Analysis Reports, namely, NOB (export direction) and Victorville (export direction), the FTR scheduling in August 2001 was on the average insignificant to moderate.

FTR Scheduling Statistics in August 2001

Branch Group	COI IMP	ELD IMP	IID-SCE IMP	MEAD IMP	PV IMP	SilvPk IMP	VictVl IMP	ELD EXP	MEAD EXP	PV EXP	P26 EXP	VictVl EXP
MW FTR Auctioned	600	707	600	487	1,819	10	1,013	626	456	796	1,727	296
Avg. MW FTR Scheduled	44	576	410	5.6	603	9.7	10	59	138	259	90	77
% FTR Scheduled	7%	81%	68%	1.1%	33%	97%	1%	9.5%	30%	33%	5%	26%
Max MW FTR Scheduled	229	707	445	50	899	10	11	275	338	605	492	152
Max Single SC FTR Schedule	101	582	445	50	600	10	11	225	213	380	492	152

VII. Issues Under Review and Analysis

FERC Refund Hearings

DMA staff continues to perform extensive analysis and support in response to FERC's July 25 Order on refunds in California's wholesale energy market. As part of these proceedings, DMA is providing extensive support in responding to legal interrogatories, and is providing data from the ISO's Settlements and operational data systems to FERC and participants in the proceedings. Data and analysis being provided in this proceeding is subject to special confidentiality agreements. The refund period covered in these proceedings ranges from October 2, 2000 to June 20, 2001.

Cost Review Under June 19 Order

DMA staff is performing a review of cost justifications submitted by suppliers with bids and sales of real time energy and ancillary services over mitigated price levels since June 20, which are subject to cost reporting and refund under the June 19 Order. On September 7, FERC ordered refunds for all bids over the mitigated price levels in June by Mirant, Reliant, and Williams, on the grounds that cost justifications submitted by these suppliers for bid prices above the proxy market clearing price (mitigated price) in June were not filed in a timely manner and/or were inadequately supported. FERC also noted that sellers who made wholesale sales in the spot markets in California and the rest of the WSCC in excess of the mitigated price during June, but did not file cost justifications within the time period provided for doing so, are not entitled to receive more than the mitigated price.

Path 15 Expansion Analysis

DMA is currently undertaking a study to examine the potential economic benefits from adding new transmission capacity to Path 15. PG&E and the CPUC are currently considering the feasibility of installing a new 500 kV transmission line between PG&E's existing Los Banos Substation and its existing Gates

Substation. This project would add an additional 1,400 MW of new firm use capacity to Path 15. The cost of the project is estimated at $300 million and if approved, the project would be completed by 2005. In assessing the economic benefits of this project, DMA is particularly interested in evaluating the impact this additional transmission capacity would have in mitigating market power. By creating additional import capability into northern California, the expansion has the potential to mitigate the ability of suppliers in northern California to exercise market power. DMA is conducting analysis to assess the potential cost impact to consumers from market power in 2005 and evaluating the extent to which the expansion of Path 15 would reduce that cost impact. DMA expects to issue a final report on this study in late September and it is anticipated that this report will also be filed with the CPUC.

Undergeneration To Offset Credit Risk

There has been some concern that in recent months several New Generation Owners (NGOs) have engaged in a practice of undergenerating in real-time, in comparison to their forward market schedules and dispatched real-time bids, in an attempt to reduce the amount owed them by the bankrupt UDCs (utility distribution companies). The DMA was asked to perform an analysis to determine (1) whether NGOs are in fact undergenerating, and (2) if so, whether they would pursue such a strategy out of concern for credit risk, or if other market incentives could explain such behavior.

The DMA analyzed the level of under- and over-generation in each hour by individual NGOs as well as individual IOUs in two months, namely, May and July, 2001. July was selected because the presumed behavior is suspected to have been particularly pronounced in that month. We also included May for comparison, as metered data in that month is complete.

In general, the NGO deviations from scheduled and/or dispatched levels do not show a clear pattern of undergeneration. Deviations in both directions (undergeneration and overgeneration) are observed. However, at least one NGO appears to have undergenerated more systematically. This may be attributed to the pursuit of market price signals as well as offsetting debts. Regardless of the reason of the undergeneration, the large amount of undergeneration can potentially undermine system reliability. ISO is considering ways to ensure better adherence to schedule and more effective dispatch control.

Target Price

The original Target Price was set at the level where the overlapping INC and DEC bids would have cleared the market. In early 2000 some market participants started to abuse this mechanism and control the Target Price by submitting a large volume of phantom DEC bids at their desired price. To prevent this new game, the ISO modified its Target Price methodology starting April 4, 2000 (for Trade Day April 5, 2000). The modified Target price was set at the lower of the lowest INC bid or $0/MWh. Although this eliminated some of the observed gaming behavior, it had some undesirable consequences. The modified Target Price resulted in the elimination of a portion of the real-time DEC market, increased real-time price volatility, and increased the cost of Regulation capacity as Regulation bidders would internalize real-time price risk associated with low Regulation Energy price in their Regulation capacity bids.

The DMA has actively taken part in the design of a new Target Price to alleviate the problems with the earlier designs. The new design is based on the original Target Price methodology, but with important modifications as follows:

1. Compute the original Target Price, using only the feasible bids (pre-dispatched import bids, generation bids within 10-minute ramp rate, and dispatchable load bids) in the BEEP stack.

2. Using gas fired unit proxy bids (for all market bids already in the BEEP stack as well as those included by the ISO as proxy bids), determine the lowest available incremental bid from the gas-fired units.

3. The new Target Price is the lower of the two. Limiting the original Target Price by the lowest available incremental gas-fired unit proxy price will eliminate any residual gaming opportunities with the original Target Price that may still persist despite using only feasible bids.

The new Target Price will then be used to modify the overlapping bids in the full BEEP stack, including the proxy bids added by the ISO.

Regulation Energy Payment

There has been insufficient supply of bids into the regulation market. Some resources that have frequently provided significant Regulation service to the ISO in the past have stopped participating in the Regulation markets in the recent months. These are mainly generating resources belonging to the IOUs. The DMA has been participating in investigating the problem and developing recommendations. The main issues that have been identified as contributing to the lack of resources participating in the Regulation market are as follows:

1. Settlement of Regulation Energy as Uninstructed Deviations. The risk of unfavorable Energy pricing (which with the current Target Price methodology could include generators receiving $0 for increasing output) has diminished the supply of Regulation service offered to the ISO.
2. Specific issues of concern to the IOUs are:
    a) Upward Regulation: Reserving upward Regulation capacity increases the exposure to under-scheduled Load penalties for Load serving entities. When a Load serving entity reduces the total Energy scheduled from their resource portfolio to reserve capacity for Regulation, they reduce the amount of Load that they can forward schedule thereby increasing the possibility that they may incur under-scheduled Load penalties.
    b) Downward Regulation: A unit providing Downward Regulation is charged for the scheduled energy that is not delivered due to Downward Regulation instructions. Although it receives a Downward Regulation capacity payment, it may end up with a net charge. With the current credit worthiness issues, the IOUs appear to play it safe and keep the energy to serve their hour-ahead scheduled obligations.

Several solutions are being considered to deal with these issues, including 1) long-term contracts (rather than or in addition to day-ahead and hour-ahead Regulation markets), and 2) improving the supply of regulating resources through an improvement in pricing of regulation energy.

Posting of Price Data

At present, the ISO settles the real time imbalance energy it procures using the following different procedures:

- Market-clearing price (MCP) for bids below the prevalent price cap. (with 10% adder)
- As bid for bids above the price cap, subject to justification and refund.

Information regarding energy dispatched within the MCP is readily available. However, information regarding energy dispatched above MCP (and paid as bid) is limited. Many SCs have disputed their settlement statements, based on this lack of data availability. In addition, many SCs have shared their concerns that even absent settlement disputes, there is inadequate transparency into real time energy purchases if the ISO does not release additional data.

The ISO has set forth plans to publish on OASIS additional information about real time energy purchases starting late September, and has asked DMA's opinion on the issue. DMA believes that the information published at present, namely, incremental and decremental prices, total positive and negative Acknowledged Instructed Energy (AIE) and positive and negative Out of Sequence (OOS) energy is adequate to provide efficient market signals. The DMA is concerned that without the proper controls, publishing contemporaneous information about the bids available in the BEEP stack, and hourly as-bid and OOM prices could invite tacit collusion and market gaming. This is because, although all market participants would not be eligible to earn the hourly OOM or as- bid price, they could use this information to take actions such as strategic withholding to drive up prices. To facilitate verification of settlement statements, however, the DMA would recommend publishing the average of hourly as-bid and OOM costs with an appropriate time delay.