Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers, ISO Board Assistants

Date: October 19, 2001

Re: Market Analysis Report for September 2001

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

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

EXECUTIVE SUMMARY

Real-time electricity and ancillary service prices fell in September due primarily to the lowest natural gas prices in at least two years, high generation availability, weak demand, and service of load by forward contracts. On average, the real-time price of electricity decreased approximately 19%, to incremental and decremental energy prices of $48 and $19 per megawatt-hour (MWh), respectively, from the August averages of $55 and $11.[1]

Loads in September 2001 were lower than those in September 2000, due primarily to mild weather, continued conservation efforts by consumers, and a softening economy. The California Energy Commission (CEC), which provides estimates of conservation after normalizing for growth and weather conditions, reported that normalized demand in September 2001 was 5.4 percent below that of September 2000.

The Federal Energy Regulatory Commission's (FERC) price mitigation order of June 19 continues to be in effect, imposing a soft price cap of $91.87/MWh on wholesale power markets in the Western United States. However, the cap has largely been non-binding in September due to the soft market environment.

The portion of energy transactions that is traded in the ISO's real-time balancing energy ex-post price (BEEP) market has continued to decline. In January, the Department of Water Resources' California Energy Resources Scheduling Division (CERS), entered into forward contracts on behalf of utility distribution companies (UDCs) that have been sufficient to meet most of the UDCs' net-short load in September.

The soft demand situation has mitigated the ability of generators to exercise market power in the real-time markets. However, real-time prices have once again risen above the competitive benchmark in September. While the price-to-cost markup has remained relatively low since June, it increased in September. High bids currently not called on by the ISO continue to be offered by generators. In addition, instances of within-zone congestion have increased as new generation locates within the ISO control area, potentially

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[1] As of this report, the DMA will report separate real-time incremental and decremental energy prices. The real time price is the average of the market clearing price and OOM purchase costs. See Table 1 under the California Wholesale Markets section for a further breakdown.

enabling generators to exercise locational market power. Figure 1 shows bids into the BEEP stack by price bin during September and Figure 2 compares actual prices of real-time energy to baseline estimates of competitive prices, which approximate the costs of production of electricity.

Figure 1. Original Bids into BEEP Stack (Hourly Average by Day)

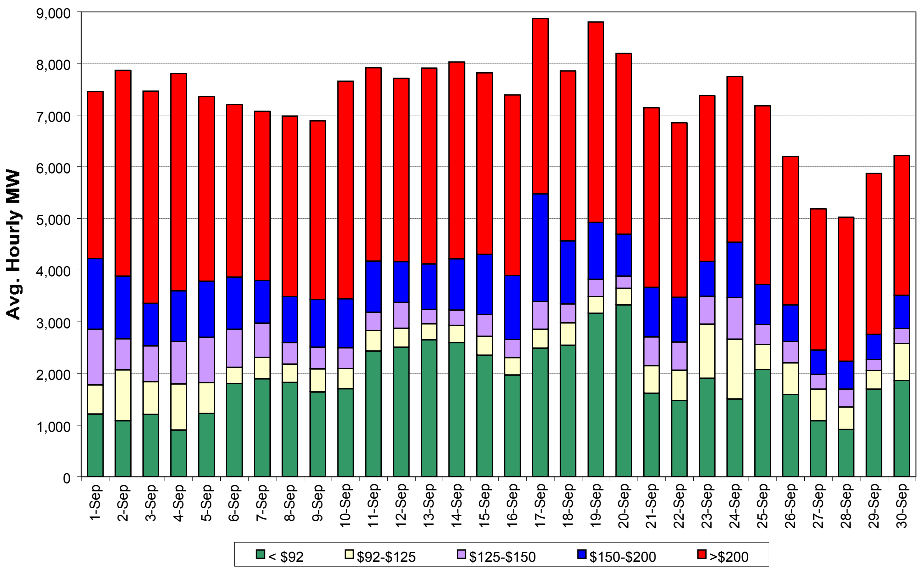
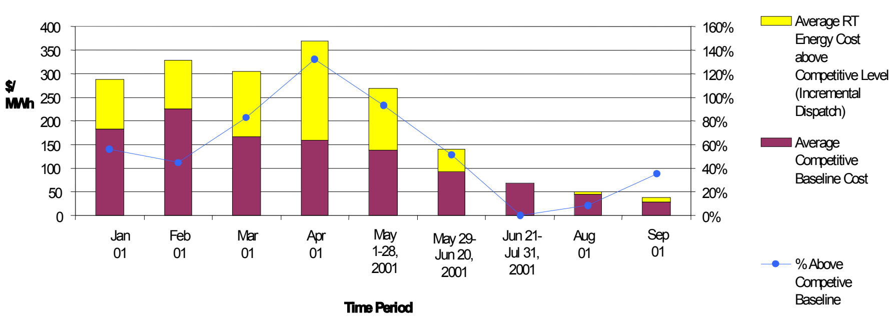
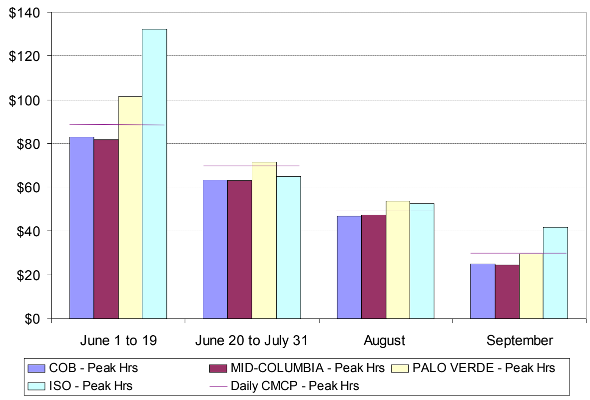


Figure 2. Price-Cost Mark-Up in ISO Real-Time Market



When we compare the competitive baseline to other Western regional spot market prices, we see similar reductions in the mark-ups of suppliers in those markets as well. Figure 3 shows spot prices for California Oregon Border, Mid-Columbia, Palo Verde, and the ISO real-time price, compared to the California competitive baseline cost. For the period of June 20 to August, average regional prices were near the California competitive baseline cost. In contrast, ISO real-time price and Palo Verde price were significantly above the benchmark price in early June and the ISO real-time price is once again above the benchmark price in September. However, it should be noted that the California competitive baseline is not necessarily representative of the costs of other regional suppliers.

Figure 3. Regional Spot Prices Compared to Daily California Competitive Baseline[2]



Other key market activities include the following:

- **Spot natural gas prices decreased from $3.27/MMBtu in August to $2.42/MMBtu in September**. 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 soft demand, resulting from mild weather across the region, and ample supply.

- **Underscheduling of loads remains low**. The forward purchases of the California Department of Water Resources' California Energy Resources Scheduling Division (CERS) helped to on average eliminate the underscheduling of loads in September. However, there appear to be instances of overscheduling of supply resources in several hours in September, particularly during off-peak periods.

- **Lower Ancillary Services Costs.** Ancillary service (A/S) prices decreased between August and September, with an increasing portion of A/S self-provided by scheduling coordinators. Total A/S costs were $19 million in September, down from the August total of $50 million, representing a decrease from $2.38 to $0.97 per MWh of load served.

- **Low Inter-zonal Congestion Costs.** Day-ahead inter-zonal congestion in September was primarily limited to imports on COI, South-to-North congestion on Path 15, and small amounts of imports on Eldorado. Total inter-zonal congestion costs for September decreased to approximately $1.6 million from $2.4 million in August.

[2] COB, Mid-Columbia, and Palo Verde prices are the average firm peak prices as reported by the "Energy Market Report." ISO prices are the average INC price during peak hours.

- **Increase in Intra-zonal Congestion Costs.** New generation has increased instances of intra-zonal congestion, raising intra-zonal congestion costs.

KEY MARKET CONDITIONS FOR AUGUST 2001

I. California Wholesale Energy Markets

- **Loads.** Monthly system energy consumption for September totaled 18,984 GWh, a 7.9% decrease from September 2000, reflecting continuing conservation efforts by California consumers. The peak load for the month reached 37,751 MW, a 12.4% decrease from the September 2000 peak of 43,069 MW. Daily peak loads averaged 32,376 MW, a 7.25% decrease from September 2000. The California Energy Commission provides estimates of conservation after normalizing for growth and weather conditions. In September, the CEC calculated that monthly peak demand for electricity decreased by 8.0 percent from September 2000, and monthly energy dropped by 5.4 percent over the same period.

- **Wholesale Energy Prices.** On June 20, the FERC's West-wide price mitigation Order of June 19 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 has remained unchanged since the Order went into effect, because the ISO has not operated under a Stage 1 emergency for a full hour since that time. 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; however, no generator has yet succeeded in justifying bids above the cap.[4] On October 5, 2001, the FERC ordered that generators must refund amounts in excess of mitigated prices from July due to untimely and/or unsupported cost justifications filed by suppliers.

  DMA monitors several key price and volume statistics related to the real time market. The BEEP market now consists of several components displayed in numbered columns: (1) The market clearing prices (MCP) and quantities for incremental and decremental energy procured under the price cap; and (2) The incremental and decremental out-of-market (OOM) procurements scheduled in real-time. The combination of these components yields (3) the total overall average real-time prices. CERS real-time procurements on behalf of the IOU's comprise the bulk of the OOM activity. The quantity of energy procured as-bid above the price cap from the BEEP market was negligible in September. The averages for each of these segments of total real time purchases for peak, off-peak, and all hours are shown in the following table:

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[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.

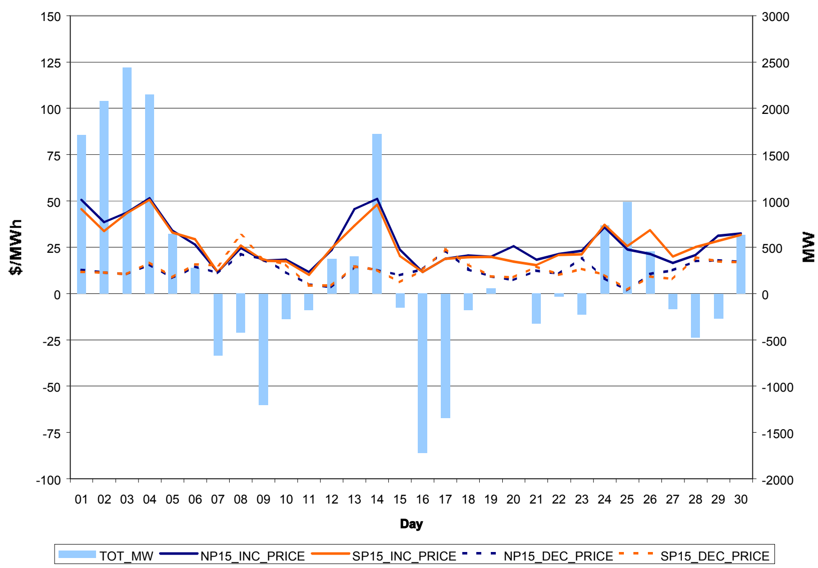
Table 1: Real Time Energy Price Summary for September 2001[5]

	Avg. Market-Clearing 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 and Percent Underscheduling (4)
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$61.43	$7.23	$47.33	$33.75	$51.36	$20.92	59526 MW
	120 GWh	103 GWh	300 GWh	109 GWh	420 GWh	212 GWh	1.2%
Off-Peak	$45.82	$3.28	$33.25	$21.64	$37.82	$15.68	21982 MW
	41 GWh	47 GWh	73 GWh	97 GWh	114 GWh	144 GWh	-3.2%
All Hours	$57.43	$6.00	$44.59	$28.05	$48.47	$18.80	27169 MW
	162 GWh	149 GWh	373 GWh	207 GWh	534 GWh	356 GWh	0.0%

Dollar figures are $/MWh and GWh figures are total volume. The values in Columns (1) do not include the 10 percent risk premium adder that is paid to all sellers receiving the MCP. BEEP procurements above the price cap (paid as-bid) totaled approximately 6 MWh, all incremental, at an average cost of $173/MWh, and had no material effect on average prices. 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 September is estimated at $51/MWh.

- Average real time prices decreased approximately 19% from August to September. Total loads increased, while average hourly underscheduling as a percent of load decreased from 0.5% to less than 0.1%. One factor that contributed to the differences in real time prices was a decrease in the average spot price for natural gas, which fell from $3.27/MMBtu in August to $2.42/MMBtu in September.[6] Figure 4 shows the daily average real-time prices and quantities for incremental and decremental energy in September (monthly averages are noted in column (3) of Table 1 above).

Figure 4: Daily Average Real-Time INC and DEC Energy Prices and Quantities September, 2001



[5] The values in Table 1 do not include the 10 percent risk premium adder that is paid to all sellers receiving the market-clearing price.
[6] Average spot price for natural gas is equal to the average of PG&E Citygate and Southern California Border prices.

II. <u>Ancillary Services Markets</u>

Ancillary Service Prices

- The five ancillary services (A/S) are procured through a day-ahead and an hour-ahead market to meet reserve requirements. The ISO is interpreting the FERC's Order of June 19, 2001, to cap A/S prices at the effective real time price cap in all hours. Reserve requirements that are not met at prices at or below the soft cap are purchased at the bid price and again are subject to just and reasonable cost review by the FERC. Since December 31, 2000, the ISO has been rescinding capacity payments for Replacement Reserve services whenever energy is dispatched from the corresponding resource in real time. This has resulted in savings ranging from $10 million to $20 million per month.

- Scheduling coordinators (SCs) have been self providing an increasing portion of their A/S requirements. Figure 5, below, shows the increase in SCs' self-provision of A/S.

- Average prices for A/S fell between August and September. Regulation Up, Regulation Down, Spinning Reserve, Non-Spinning Reserve, and Replacement service prices decreased by approximately 53%, 35%, 75%, 90%, and 10%, respectively . Between 61% and 99% of requirements were purchased in the day-ahead market. Table 2, shown below, summarizes the weighted average prices and quantities of A/S procured in September, in both the day-ahead and hour-ahead markets.

- Table 3 compares the weighted average A/S prices in the day-ahead market, in peak and off-peak periods, with the percentage of hours during which the ISO procured A/S zonally (day-ahead and hour-ahead combined) in September.

Table 2. Summary of Weighted Day-Ahead A/S Prices by Market – September 2001[7]

	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	$ 21	$ 22	$ 21	551	5	99%
Regulation Down	$ 17	$ 11	$ 17	508	28	95%
Spin	$ 3	$ 2	$ 3	1189	26	98%
Non-Spin	*	*	*	977	45	96%
Replacement	*	*	*	45	29	61%

[7] 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. Prices that vary between NP15 and SP15 are a result of quantity-weighting of identical prices, and do not indicate zonal procurement due to congestion.

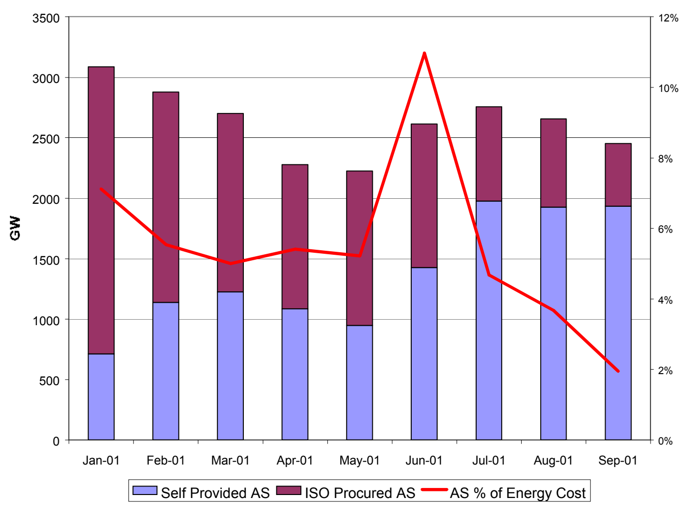
Table 3. Summary of Weighted Day-Ahead A/S Prices by Zone and Period – September 2001

	NP15		SP15		
	Peak	Off-Peak	Peak	Off-Peak	Pct. of Hours with Zonal Procurement
Regulation Up	$ 22	$ 19	$ 25	$ 20	0%
Regulation Down	$ 14	$ 21	$ 16	$ 25	0%
Spin	$ 5	*	$ 3	*	0%
Non-Spin	*	*	$ 10	*	0%
Replacement	*	*	$ 6	*	0%

* Denotes prices below $1

Since January, SCs have increasingly self-provided A/S. Figure 5 shows the volume of A/S self-provided by SCs, compared with the volume procured through the ISO ancillary service markets.

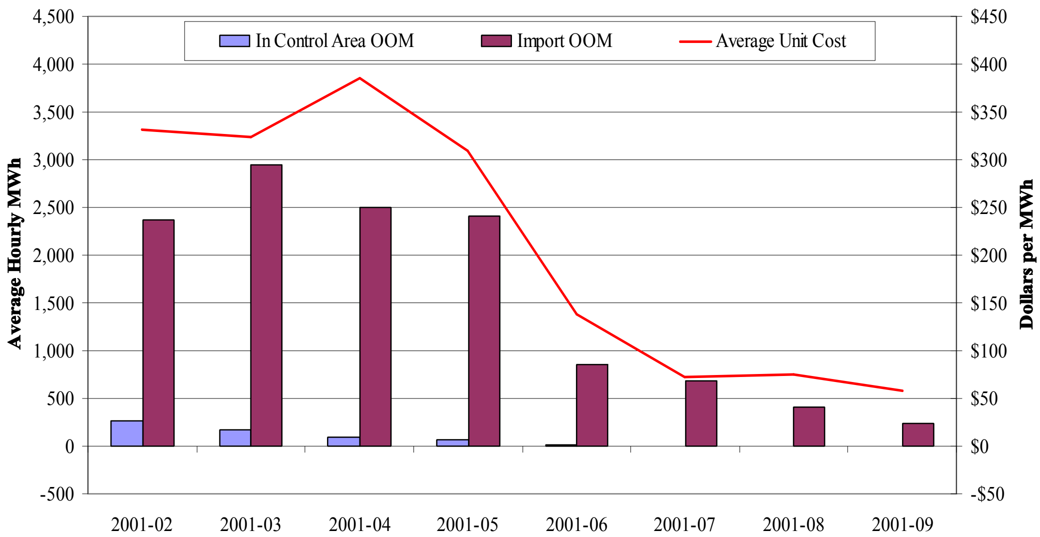
Figure 5. Provision of Ancillary Services



III. <u>Out of Market Calls (OOM) and BEEP Volumes</u>

The average OOM price for real-time energy was $58/MWh in September, or $18/MWh less than the August average of $76/MWh. On an hourly average basis, 231 MW were purchased out of market in September, which represent a continued decline on purchase volume since March. 100% of the OOM electricity was purchased from imports in August and September. The total cost of real-time OOM procurement in September was $9.7 million.

Figure 6. Quantities of Out-of-market Purchases (Average Hourly)
February 2001 - September 2001



IV. Summary of Market Costs

The cost of energy and A/S totaled approximately $996 million in September, down from $1.4 billion in August. This is the fourth consecutive month in which the total costs of energy and A/S were below those in the same month in 2000. The average cost of energy and A/S decreased from $67/MWh in August to $51/MWh in September. Energy and A/S costs continue to be above those seen in the first two years of operation. Energy and A/S costs for the first ten months of ISO operation in 1998 totaled approximately $5.55 billion, and averaged $33/MWh. Total costs of energy and A/S in 1999 were comparable to 1998 at approximately $7.03 billion (for twelve months), with an average of $33/MWh as well. However, 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. For January through September 2001, total energy and A/S costs have exceeded $24.1 billion, with an average cost of $141/MWh of load served. This represents a significant cost increase over the first nine months in 2000, in which energy and A/S costs totaled approximately $16.5 billion. The increase is due primarily to the extraordinary costs incurred between January and May 2001. This trend reversed in June, and prices for the summer have been lower than in 2000. Table 4 on the next page provides a summary of Energy and A/S costs. The costs estimated in this table include estimates for utility generation, CERS purchases, and bilateral transactions to serve load within 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	21,048	21,571	$ 1,329	$ 34	$ 50	$ 1,363	$ 1,414	$ 65	$ 2.38	3.7%	$ 67
Sep-01	19,562	19,562	$ 958	$ 19	$ 19	$ 977	$ 996	$ 50	$ 0.97	1.9%	$ 51
Total 2001	171,381	164,388	$18,755	$ 4,128	$ 1,308	$22,883	$24,190				
Avg 2001	19,042	18,265	$ 2,084	$ 459	$ 145	$ 2,543	$ 2,688	$ 138	$ 7.87	5.5%	$ 146

***** 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

V. Inter-zonal Congestion Management Markets

Congestion in September was limited primarily to day-ahead imports on COI and Eldorado; hour-ahead imports on Sylmar; day-ahead South-to-North activity on Path 15; and small amounts of hour-ahead exports on CFE and Path 26. Total congestion costs for September decreased to approximately $1.6 million in September from $2.4 million in August. Import congestion on COI accounted for over $1.2 million of the total congestion costs in September.

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

Table 5: Day-Ahead Market – Congestion Summary for September 2001

	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	All Hours	Peak	Off peak	All Hours
COI (Import)	2.5%		1.7%	$120		$120
Eldorado (Import)		5.4%	1.8%		$0	$0
Path 15 (S-N)	4%	37.9%	15.3%	$0	$.02	$.02

Performance of the Day-ahead Adjustment Bid Market in September 2001

With the changes in the forward energy market structure after the demise of the California Power Exchange (PX), a noticeable reduction was observed in the volume of Adjustment Bids needed to manage congestion, particularly in the day-ahead market. The situation has improved recently. The DMA has defined an Adjustment Bid Sufficiency Index (ABSI) to quantify and track the sufficiency of Adjustment Bids to manage day-ahead congestion. We focus on the day-ahead market out of concern that high concentration of firm transmission rights (FTRs) on some paths may provide an incentive for some FTR owners to create day-ahead congestion with a portion of their FTR capacity in order to increase congestion revenues for the unused portion of their FTRs. Admittedly, there may be a variety of other reasons (unrelated to FTR concentration) for possible bid insufficiency in the Adjustment Bid market as well.

The ABSI is defined as the ratio of the "Manageable Congestion Range" (MCR) to the "Congestion Amount" (CA). The MCR is the amount of congestion relief (scheduled flow reduction) that can be managed using Adjustment Bids submitted by the SCs (while respecting market separation). The CA is the amount of congestion relief actually required (i.e., the difference between the initial and final schedules on the path).

The ABSI is computed only for those paths (branch group and direction) where there is day-ahead congestion. An ABSI of 100% or higher indicates that there are adequate Adjustment Bids to manage congestion. An ABSI less than 100% designates adjustment bid insufficiency. The following table shows the ABSI statistics (Minimum and Average) for the month of September 2001.

Table 6: Day-ahead Adjustment Bid Sufficiency Index for September 2001

Branch Group	Direction	ABSI MIN	ABSI AVG
COI	IMPORT	111%	190%
PATH15	IMPORT	246%	711%
Eldorado	IMPORT	366%	614%

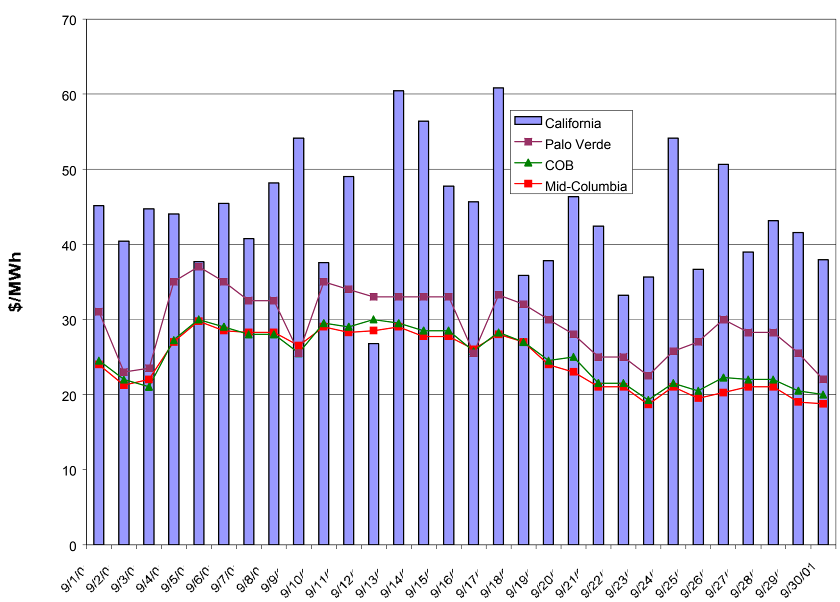
Table 6 indicates that in the month of September all day-ahead congestion was managed using Adjustment Bids submitted by the SCs (referred to as "economic" Adjustment Bids to distinguish them from "default" Adjustment Bids used when there are inadequate economic Adjustment Bids to manage congestion). It should be noted that the ABSI in table 6 includes economic Adjustment Bids tied to loads which are not necessarily dispatchable. In certain instances, there may not have been sufficient Adjustment Bids tied to dispatchable load and generation to relieve congestion in the forward market thereby shifting the congestion to the real time market. In the month of September, real-time inter-zonal congestion re-appeared for 2 hours (September 20, hours 23 and 24) on the paths where congestion had been managed in the day-ahead market.

VI. Western Regional Market Prices

Western Regional Electric Spot Market Prices

Western peak power prices continued to decline with low volatility in September, as gas prices continued to decrease throughout the region. Peak power prices[8] in the WSCC rose moderately in early September, due to some generation unit outages and an increase in Southwest cooling demand; however, price increases were abated by low gas costs. Mild weather across the region continued to keep prices near the $30/MWh level, even though many generation units were off-line. Following the terrorist attacks on September 11, trading was light, resulting in mostly stable prices due to an abundant supply of electricity available to meet demand. Slightly higher prices were seen in California due to weather-related demand and a decrease in the amount of available in-state generation. As day-ahead trading began to return to normal, supply far outweighed demand, forcing prices downward. However, cheap natural gas resulted in prices near the $20/MWh level for most Western trading points at the end of the month.

Figure 7: Western Firm Peak Prices



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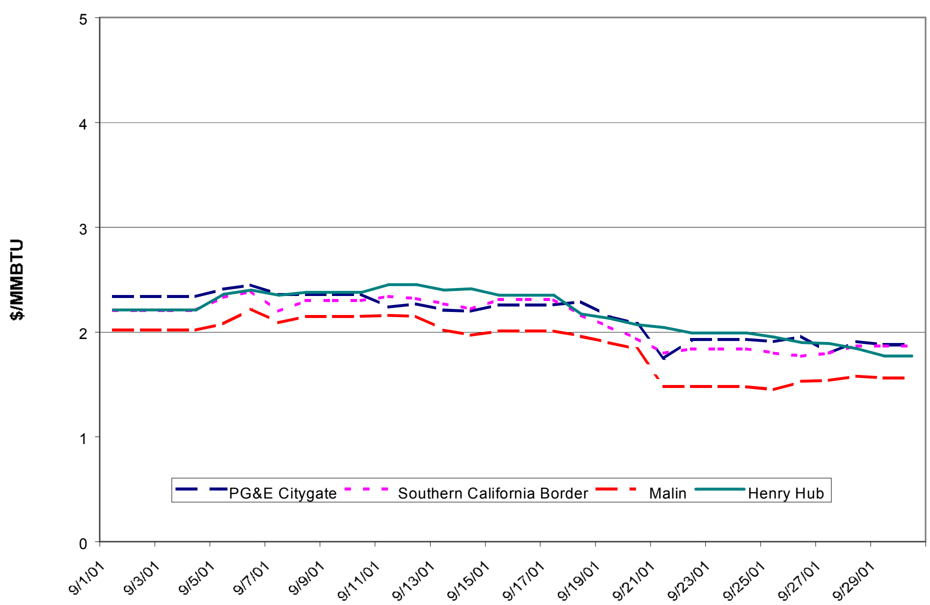
[8] Palo Verde, COB and Mid-Columbia prices are peak firm heavy load prices as reported by the "Energy Market Report." California prices are the daily average peak ISO INC prices.

California Natural Gas Prices

California spot natural gas prices continued to fall through September, resulting in prices at all California trading points below $2/mmbtu by the end of the month. PG&E Citygate prices exceeded Southern California Border Prices, due to demand from agricultural processing activity in Northern and Central California. In addition, SoCalGas is ahead in its planned storage injections, which has helped to keep Southern California prices low. Trading slowed considerably in the wake of the terrorist attacks on September 11, keeping prices essentially flat throughout California at just above $2/mmbtu. Prices fell again in the third week of September due to the continued weakening of the global economy. On Thursday, September 20, Southern California Border prices averaged below $2 for the first time in over two years, only to fall further later in the week. The fundamental market weaknesses of mild weather and storage inventories near capacity have seen little change in recent weeks. However, the softening of the economy, especially in those areas affecting energy use, has put additional downward pressure on gas prices. By the end of the month, prices settled at $1.56, $1.87, and $1.88, for Malin, PG&E Citygate, and Southern California Border, respectively.

Figure 8: Regional Natural Gas Spot Prices



VII. Performance of the Firm Transmission Rights Market in September 2001

FTR Concentration

There were no secondary FTR market trades and no FTR SC reassignments in September 2001. Since there were also no trades or reassignments in August, there have been no changes in FTR ownership concentrations since the July 2001 Report.

FTR Scheduling

On most paths FTRs have been used primarily for their financial entitlement to hedge against transmission usage charges. The relative volume of schedules with FTR priority attached on all paths amounted to 17% of the total available FTR volume in September, compared to 21% in August. On some paths, a high percentage of schedules had FTR priority attached; for example, 100% on Silverpeak, 79% on Eldorado, and 72% 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, with related statistics. FTR scheduling in September 2001 was not generally significant on paths reported previously to have high FTR concentration; namely, NOB (export direction) and Victorville (export direction).

Deleted: .

Table 7: FTR Scheduling Statistics in September 2001

Branch Group	COI IMP	ELD IMP	IID-SCE IMP	PV IMP	SilvPk IMP	VictVl IMP	MEAD EXP	PV EXP	P26 EXP
MW FTR Auctioned	600	707	600	1,819	10	1,013	456	796	1,727
Avg. MW FTR Scheduled	69	560	434	612	10	10	100	43	33
% FTR Scheduled	11%	79%	72%	34%	100%	1%	22%	5%	2%
Max MW FTR Scheduled	178	707	446	805	10	11	244	431	324
Max Single SC FTR Schedule	101	582	446	600	10	11	209	381	324

VIII. Issues Under Review and Analysis

Intra-zonal Congestion Issues

Intra-zonal congestion refers to transmission congestion that occurs within a particular congestion zone. Inter-zonal congestion refers to congestion across congestion zones. Under the current ISO Tariff, these two types of congestion are mitigated differently.

Inter-zonal congestion is mitigated in the forward market through the ISO's Day-ahead and Hour-ahead congestion management markets. Because inter-zonal congestion spans large geographic regions, the ISO typically can call upon a large number of different Scheduling Coordinators to relieve the congestion. The ISO currently does not have a process for mitigating intra-zonal congestion in the forward market. The ISO mitigates intra-zonal congestion in real-time, and must face a limited number of resources capable of relieving the congestion constraint, due to the comparatively small geographic area. This difference can often give rise to local market power, in which a supplier, knowing the ISO will need to dispatch its units to relieve congestion, will submit either excessively high or low bids, depending on whether it is needed to increase or decrease generation, respectively. In recent weeks, there has been an increasing number of localized market power events associated with intra-zonal congestion. All of these situations have involved cases where the ISO has had to call on a limited number of suppliers to reduce scheduled output, and such suppliers have submitted large negative decremental energy bids. This means that these suppliers are able to buy energy from the ISO to serve their forward energy obligations at a negative price; or, effectively, to get paid to withhold energy. DMA has been monitoring these incidents and has informed Market Participants engaged in this behavior that it views such bidding behavior as the exercise of market power and will be reporting these incidents to the FERC. In many cases, such discussions with suppliers have resulted in suppliers moderating their bidding behavior, but not to a level that DMA would deem to be acceptable. DMA will continue to monitor this issue closely, and is working with other Departments within the ISO to develop a proposal for Tariff modifications. These modifications would permit the ISO to mitigate intra-zonal congestion in the forward market, and to mitigate bids in cases where local market power is being exercised.

Day-ahead Unit Commitment Process

DMA is providing input to the ISO on a proposal to develop a Day-ahead unit-commitment process that would provide for a more workable interpretation of the "must-offer" Tariff provision that originated from the FERC Orders of April 26 and June 19, 2001. The intent of this effort is to provide a process by which the ISO could commit units for reliability and market competitiveness on a Day-ahead basis, and to ensure that suppliers are reasonably able to recover their start-up, no-load, and variable production costs.

Real-time Market Design Issues

DMA is providing input to the ISO on a number of real-time market design issues. These include: changing the target price methodology; developing real-time economic dispatch as a long-term replacement for the target price approach; and developing penalties for significant uninstructed deviations. Some of the major issues relating to penalties for uninstructed deviations concern whether the penalties should be assessed on a unit or portfolio basis, what constitutes "significant" (i.e. establishing tolerance thresholds), and whether there should be special accommodations for certain unit types.

Overscheduling in Forward Markets

DMA is analyzing the level and causes of overscheduling in the forward markets. In recent months, the ISO has experienced significant overscheduling of generation resources in the forward markets, particularly during off-peak hours. Overscheduling occurs most significantly during hours ending 2:00 and 3:00, hour 7:00, and hour 22:00. Occurrences of overscheduling decreased from June through July, only to increase again in off-peak hours in September and the first part of October.

Refund Proceedings Pursuant to FERC's July 25 Order

DMA continues to play a major role calculating refunds for proceedings pursuant to the FERC's July 25 Order. In accordance with the Order, the scope of our analysis is limited to transactions in the ISO energy and A/S markets and the PX energy markets, from October 2, 2000 to June 20, 2001. The July 25 Order excluded purchases made by CERS from the refund calculations.

The schedule for the refund proceedings has been separated into 3 issues: (1) determination of the mitigated hourly prices; (2) re-running of ISO and PX settlements with mitigated prices, and (3) determination of refunds due, or adjustments of ISO and PX accounts receivables/payables as a result of this mitigation.

DMA staff submitted testimony on the first of these issues – the mitigated price to be used in determining refunds – on October 9, 2001, along with its calculation of the mitigated price, in accordance with the methodology specified in the July 25 Order. Responsive testimony by other parties in the refund proceedings is scheduled to be filed on November 5, with written rebuttal testimony due on December 10. An evidentiary hearing on the issue of the mitigated price is scheduled for December 17-21. The ISO's

Settlements Department is performing “re-runs,” based on the mitigated price, and an evidentiary hearing on settlements issues is scheduled for February 11-15, 2002. The current hearing schedule calls for the Residing Judge to issue a Proposed Findings of Fact and Record to the Commission on March 8, 2002.

Cost Justification Pursuant to April 26 and June 19 Orders. DMA continues to review cost justification for sales over the proxy mitigated price that sellers are required to submit to the ISO and the FERC on the 7th day of each month (for sales during the previous calendar month). The following table provides a summary of sales in the ISO markets subject to cost verification requirements and potential refund pursuant to the FERC’s Orders of April 26 and June 19. As noted in a previous section, the FERC has issued rulings disallowing payment for costs above mitigated prices during the months of June and July.

Table 8: Sales of Real Time Energy and Ancillary Services over Mitigated Price Limit Subject to Refund

	May 30-31	Jun 21-30	Jul	Aug	Sep
Energy	$1,300,296	$250,750	$182,489	$952	$0
Ancillary Services	$297,140	$1,339,430	$16,641	$0	$0
Total	$1,597,435	$1,590,180	$199,129	$952	$0
Number of Sellers	11	14	13	1	0

Pursuant to the Commission’s Order of June 19, no price mitigation was in effect from June 1-20, since price mitigation under the April 26 Order in effect during this period only applied during reserve deficiency hours (Stage 1, 2 or 3 Alerts).

The Commission has not issued a ruling on any sales during hours of reserve deficiency on May 30-31, when the proxy price mitigation of the April 26 Order was in effect. The July 25 Order provides a formula for determining refunds for the period of October 2, 2000, to June 20, 2001. However, language in the July 25 Order excludes from its purview the reserve deficiency hours of May 30-31, and notes that prices during those hours had already been mitigated under the April 26 Order.

As shown above, a very limited amount of sales were made above mitigated prices during August and September.

Weekly Reports to FERC Pursuant to April 26 Order. DMA continues to provide confidential weekly reports to FERC on bidding patterns in the ISO’s markets.