Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: October 17, 2002

Re: Market Analysis Report for September, 2002

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

Executive Summary

September began with two fires that significantly curtailed the transfer capability of Path 26, a key transmission line connecting the Northern and Southern California power grids, causing the ISO to split its imbalance energy market between Northern and Southern California, and necessitating limited out-of-market calls. These were followed by relative stable markets for the rest of September.

An increase in the cost of real-time energy somewhat offset a decrease in forward energy volume and cost in California between August and September. The net effect of these changes was an average cost consistent with those seen in other months since October 2001. Specifically, the cost of wholesale energy and ancillary services in the ISO Control Area averaged $44 per megawatt-hour (MWh) in September. Of note was the growth in volume of real-time incremental (INC) energy for delivery in peak hours, which increased 111 percent, contributing to a 172 percent total cost increase for peak-hour INC energy since August. The overall INC price rose as a result to $57.69/MWh in September, up approximately 23 percent since August. The price for decremental (DEC) energy also rose 7 percent to $10.65/MWh, effectively helping to lower total costs to load. Substantially greater deviations between forward schedules and actual load over the last few months have necessitated increases in real-time procurement, particularly during the afternoon and evening hours.

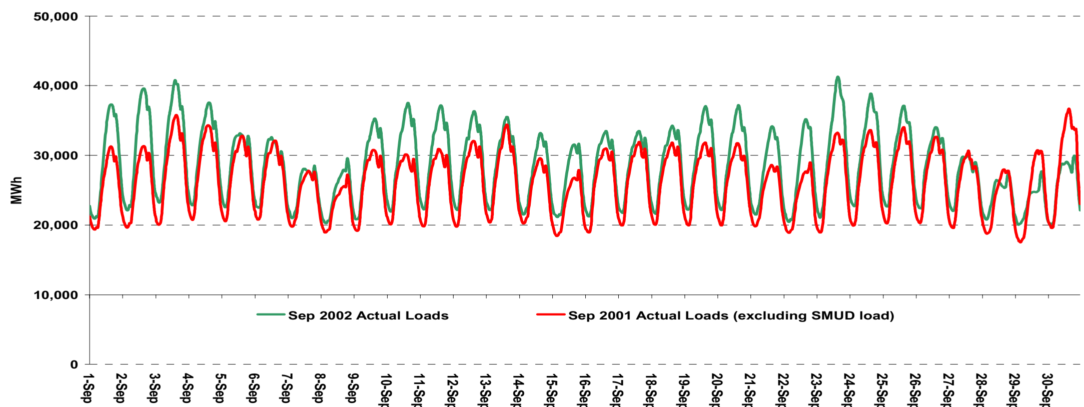
On September 26, in response to an emergency filing by the ISO, the Federal Energy Regulatory Commission (FERC) ordered a one-month delay of the change in market rules originally scheduled to go into effect on October 1. This has allowed the ISO more time to develop and test the new automated bid mitigation procedure (AMP) and other software-implemented changes in design. The rules currently in effect, including the $91.87/MWh soft price cap, will thus remain in effect through October 31.

I. Key Trends in Summer 2002

The Department of Market Analysis (DMA) has observed several trends over the last few months in the ISO's markets. These include loads in excess of 2001 levels, underscheduling during peak hours and overscheduling during off-peak hours, the return of import volumes to the ISO's real-time Balancing Energy Ex-Post Price Auction Market (the BEEP Stack), and congestion on key transmission paths between the ISO Control Area and the Pacific Northwest, Arizona, and Los Angeles.

Loads in 2002 have exceeded those seen in 2001. The California Energy Commission calculates that monthly peak demand, adjusted for changes in growth and weather, increased by 6.9 percent between September 2001 and September 2002. As in earlier summer months, this suggests that conservation efforts are beginning to wane. However, the CEC's index was 1.7 percent lower in September 2002 than in September 2000. The average load in September of 28,470 MW was 1.9 percent lower than the average August load of 29,016 MW. The following chart compares actual loads in September 2001 and 2002.[1]

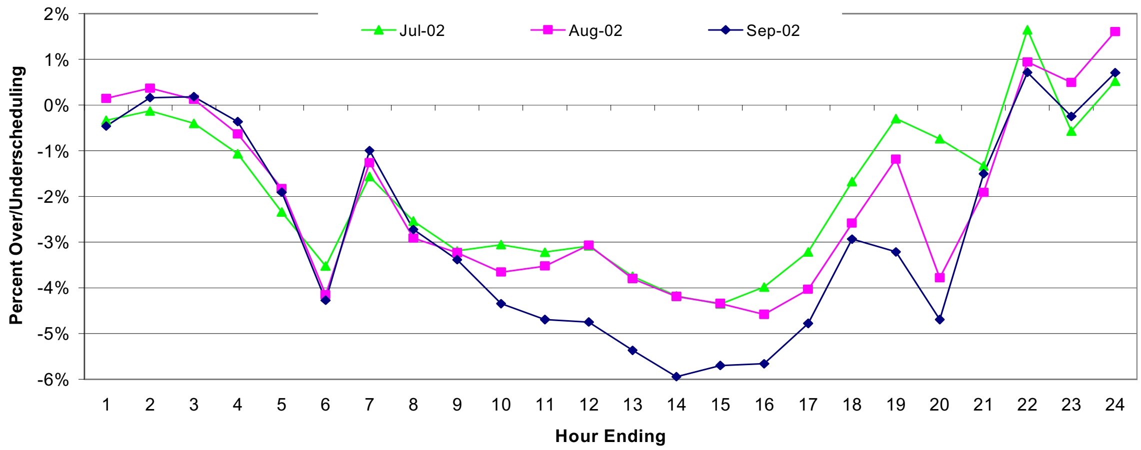
Figure 1. Actual ISO Loads in September 2001 and 2002



Another trend has been the underscheduling of forward-contracted energy in peak and morning ramp hours, and overscheduling in off-peak and evening ramp hours. This problem was especially pronounced during peak hours in September, reaching 6 percent of load on average for hour ending 14:00, compared with just over 4 percent for that hour in both July and August. Across all peak hours, underscheduling was 3.0 percent in September, compared with 2.0 percent in both July and August. This increase may be due to deviations between forecasted and actual load by load-serving entities. It requires greater levels of energy to be procured in real time to offset the deviations, heightens market risk by enhancing the potential for the exercise of market power, and occasionally may pose reliability concerns. The following chart shows scheduling deviations by hour of day for July through September.

[1] The Sacramento Municipal Utility District (SMUD) left the ISO Control area in June 2002. In the interest of consistency, 2001 loads are shown exclusive of the SMUD contribution. That is, the graph compares non-SMUD loads in both years.

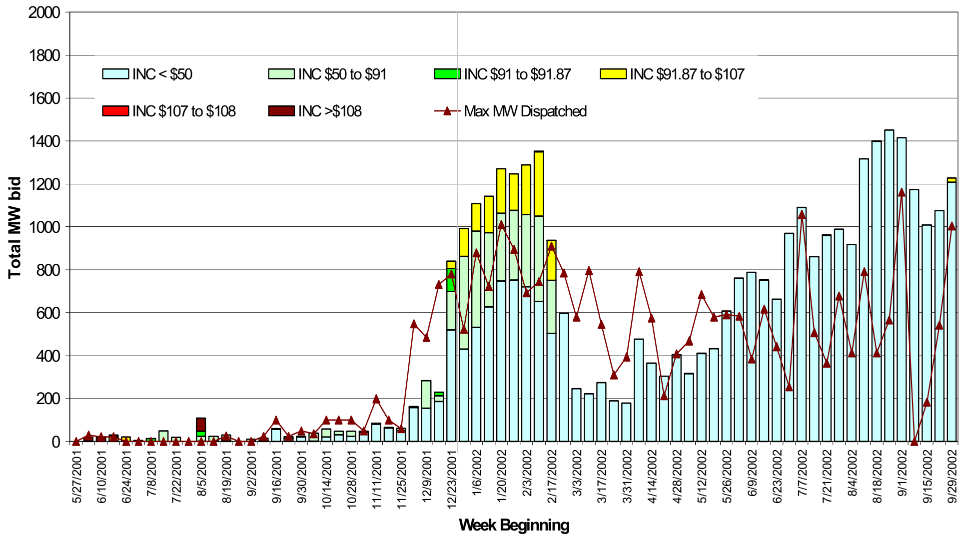
Figure 2. Scheduling Deviations by Hour of Day for July through September 2002



A third noticeable trend has been higher volumes of import energy into California, particularly from the Pacific Northwest. There had been some concern in early 2002 that market rules had resulted in disincentives for those marketers to supply electricity into the California real-time market. One of these rules has since been relaxed.[2] With the growth of imports in forward market schedules and real time bids, ISO operators have been able to utilize average monthly gross import levels in excess of 8,000 MW since May 2002, as shown below in Figure 7. The following chart shows that volumes of imports into the BEEP Stack have also been strong in July, August, and September.

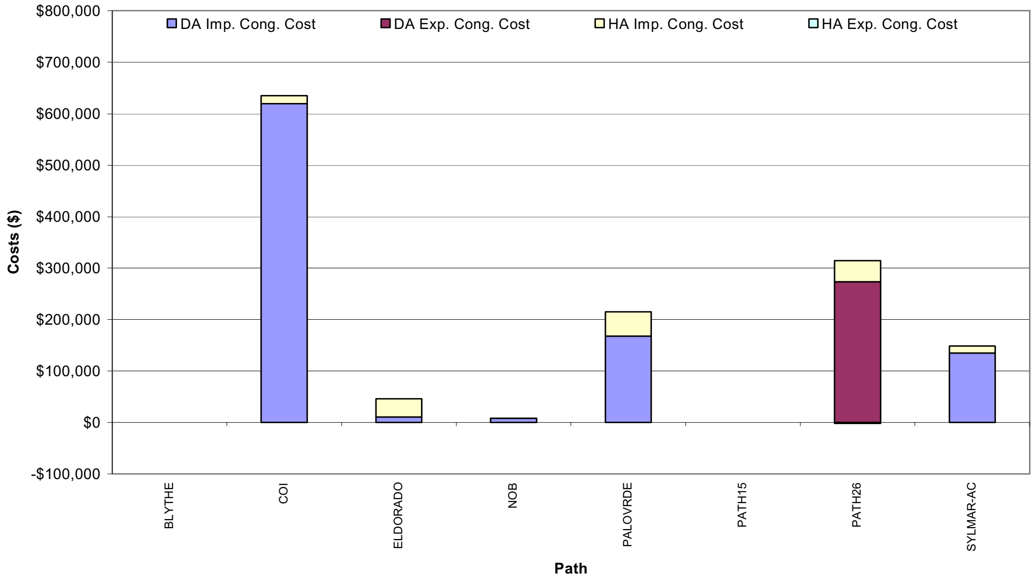
[2] These rules included the requirement that marketers of import energy would be required to bid energy into the BEEP Stack at a price of zero, and that they be paid the uninstructed energy price rather than the instructed price. The latter rule was rescinded in Amendment 43, approved by FERC in its Order of June 11, 2002.

Figure 3. Import Volumes Offered into the BEEP Stack through September 2002



Lastly, DMA has observed interzonal congestion on key transmission paths to California, such as the California-Oregon Intertie (COI); Palo Verde, which connects the ISO Control Area to Arizona; Path 26, a bottleneck between Southern and Northern California; and Sylmar, which connects the ISO Control Area to Los Angeles. The congestion on COI and Palo Verde is generally due to the high level of imports, whereas Path 26 charges accrued due to the volume of imports in the day ahead and the aforementioned fires. The following chart shows congestion by path, market, and direction in September.

Figure 4. Congestion by Path and Market in September[3]

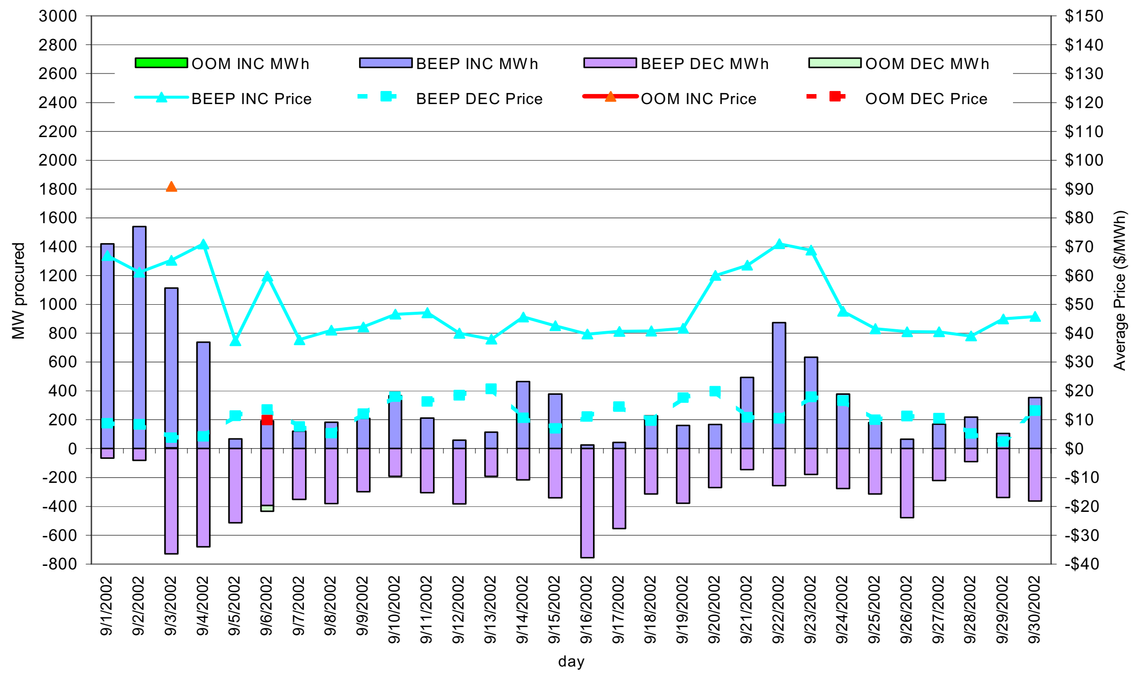


II. Real-time Market

The ISO's real-time market volumes and average costs to load increased in September. Incremental and decremental volumes procured through the BEEP Stack averaged 376 MW and 336 MW in September, respectively, compared with 272 MW and 246 MW in August. This increased procurement, along with higher natural natural gas prices, resulted in a higher average INC price, which the ISO pays to generators to increase output whenever scheduled load is not sufficient to meet actual load. The BEEP INC price averaged $57.67/MWh in September, compared with $46.52 in August. However, the average BEEP DEC price, which the ISO collects from generators when they are selected to decrease output in intervals that scheduled load exceeds actual load, increased nominally in September to $10.65/MWh, compared with $10.22/MWh in August. Other variables being equal, higher INC prices and lower DEC prices result in higher costs to load. The following chart shows average hourly load by day in September.

[3] "Exports" on Path 26 refer to the North-to-South direction; that is, electricity flowing into SP15.

Figure 5. BEEP and OOM Volumes and Prices for September



OOM Procurement. The ISO made limited out-of-market calls in a few hours in September when BEEP dispatches were not sufficient to balance scheduled generation with actual load within each congestion zone. On two peak afternoon hours on September 3, ISO operators dispatched 125 MWh of incremental OOM energy in SP15 to supplement their efforts to work around a derate on Path 26 due to fire. On the afternoon of September 6, ISO operators again found it necessary to manage a fire-related derate on Path 26 by decrementing 979 MWh of energy out of market from hydroelectric resources in NP15.

As-Bid Procurement. There was no as-bid procurement from the BEEP Stack in September.

Since September 2001, the ISO has reported separate INC and DEC prices for the real-time market. The following tables show (1) average prices and total volumes for real-time energy procured through the BEEP Stack. Also shown are (2) average OOM prices and volumes. The combination of (1) and (2) comprise (3) average real-time prices and total volumes of all real-time balancing energy. The final column (4) shows average system loads and percent underscheduling.

Table 1. ISO Real-Time Prices and Volumes for September 2002

	Avg. BEEP Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads (MW) and Pct. Underscheduling (4)
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$ 59.22	$ 11.98	$ 90.91	$ 9.89	$ 59.24	$ 11.96	31,136 MW
	245 GWh	146 GWh	*	*	245 GWh	147 GWh	3.0%
Off-Peak	$ 43.13	$ 8.63	No Procurement	No Procurement	$ 43.13	$ 8.63	23,139 MW
	26 GWh	95 GWh			26 GWh	95 GWh	0.7%
All Hours	$ 57.67	$ 10.65	$ 90.91	$ 9.89	$ 57.69	$ 10.65	28,470 MW
	271 GWh	241 GWh	*	*	271 GWh	242 GWh	2.0%

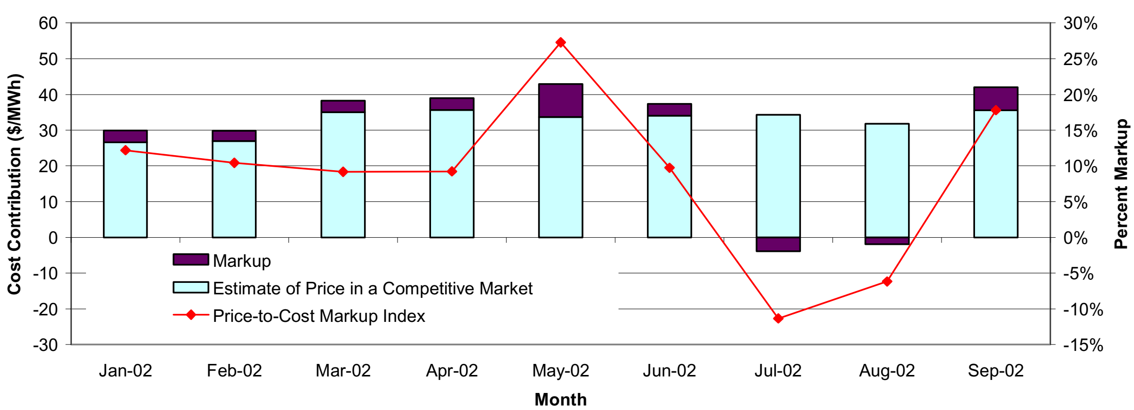
* Indicates volume below 1 GWh.

Price Cap Hits. The current soft price cap remained relatively unbinding throughout September**.** The BEEP Stack ten-minute interval price was within $1 of the soft price cap of $91.87 in 52 of 1,995 intervals (2.6 percent) in SP15, and in 14 of 1,798 intervals (0.7 percent) in NP15. Pursuant to FERC's Orders of July 16, 2002, and September 26, 2002, the price cap mitigation mechanism will be replaced by other means of mitigation as part of the ISO's 2002 Market Redesign (MD02), including a $250 soft price cap, beginning November 1, 2002.

Market Power. Market power is often measured by comparing the price paid for energy to an estimate of the price that would exist under competitive conditions. The Department of Market Analysis (DMA) tracks several such indices, all of which are calculated as the ratio of the markup included in the average price paid for wholesale electricity to an estimate of the price that would exist in a competitive market. A perfectly competitive market would be indicated by the index equal to zero (no percentage markup).

One such index is the price-to-cost markup for short-term energy, which includes costs in the ISO's real-time balancing energy market and day-ahead and hour-ahead bilateral procurement by the Department of Water Resources' California Energy Resources Scheduling Division (CERS), to cover utilities' net-short loads. The index illustrates the comparison of actual average short-term wholesale prices to estimated costs of thermal generation within the ISO Control Area. The estimated competitive baseline costs are determined by multiplying the marginal costs of the highest cost in-state generation unit needed to meet hourly load by the load for that hour. The index can show negative markups when a portion of the short-term energy is purchased from inexpensive imported hydroelectric resources at prices below the in-state thermal costs. DMA is currently investigating the specific reasons for the negative mark-ups in July and August shown below. The volume-weighted average markup for all of 2002 to date is $2.52/MWh, or 7.8 percent markup above cost. The following chart shows the price-to-cost markup in short-term energy by month in 2002.

Figure 6. Monthly Average Price-to-Cost Markup in Short-Term Energy through September

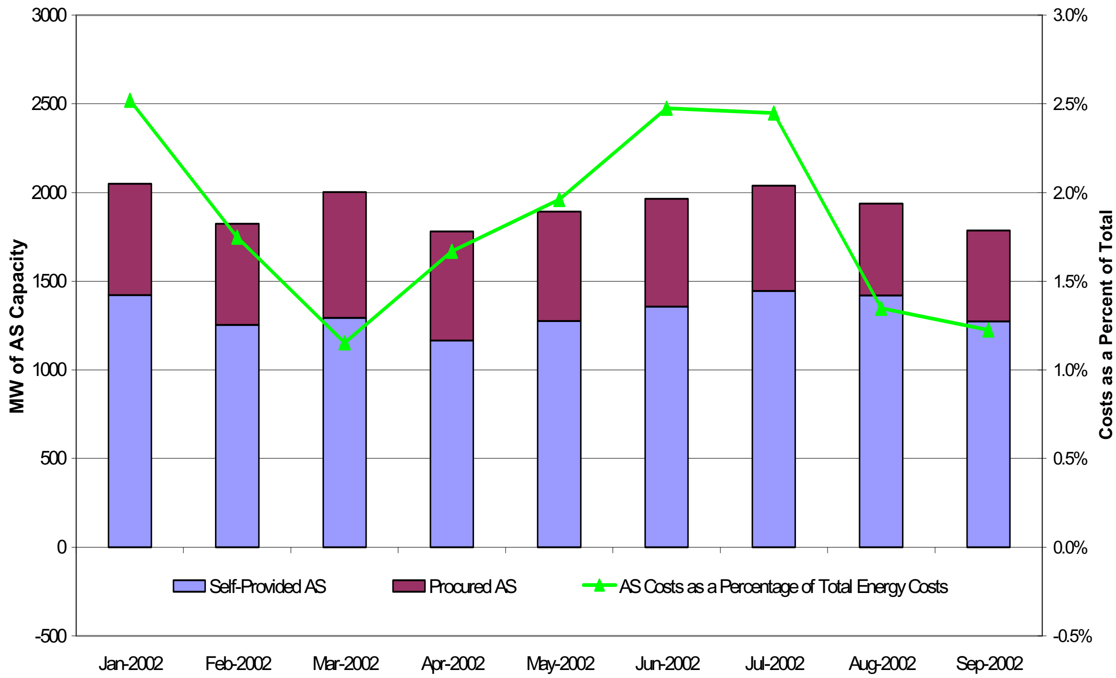


[4] DMA has revised this index since it was last reported in the June report to account for a wider portfolio of generation, including new generation that has come on line in 2002.

III. Ancillary Services Markets

Costs for ancillary services (AS) in the ISO's AS markets averaged 1.2 percent of total wholesale energy costs in September, the lowest proportion since March, as the summer's lowest average loads and normal hydroelectric conditions enabled scheduling coordinators to self-provide AS. The following chart shows monthly average self-provision of AS and cost as a percentage of total energy cost in 2002.

Figure 7. AS Self-Provision and Cost as a Percentage of Total Energy Costs



Prices for AS have generally been declining since July. The day-ahead (DA) price for Upward Regulation (RU) services averaged $12.33/MWh in September, compared with $10.32 in August and $14.95 in July. The DA price for Downward Regulation (RD) services averaged $12.00/MWh in September, compared with $11.69 in August and $16.58 in July. DA Spinning Reserves (SP) averaged $4.00/MWh in September, compared with $5.06 in August and $10.82 in July. Non-spinning reserves averaged $1.40/MWh, compared with $3.01 in August and $6.50 in July. Scant quantities of Replacement Services were procured at an average price of $1.18/MWh in September, compared with $1.01 in August and $3.21 in July. The following table shows AS price and volume statistics by market in September.

Table 2. AS Price and Volume Statistics for September

	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	$ 12.33	$ 12.26	$ 12.32	380	24	93%
Regulation Down	$ 12.00	$ 11.12	$ 11.93	410	31	92%
Spin	$ 4.00	$ 6.05	$ 4.07	775	28	96%
Non-Spin	$ 1.40	$ 4.27	$ 1.46	786	18	97%
Replacement	$ 1.18	$ 1.98	$ 1.19	29	*	97%

* Indicates average volume below 1 MW.

IV. Congestion Costs

As noted in Section I, most Interzonal congestion in September occurred on COI and Sylmar, and can be attributed to import schedules from the Northwest and Los Angeles in peak periods. In general, flows on interties drifted toward SP15.

North-to-South congestion occurred on Path 26 due to capacity derates from fires in early September, further congesting flows in the direction of Southern California. The day-ahead import congestion price on COI ranged between $3.50 and $4.00/MWh on September 5, similar to the respective differences in regional day-ahead electricity trade prices on that day. The North-to-South usage price on Path 26 ranged from $1 to $5/MWh on September 5, as the trading price in SP15 was $2.25 higher than in NP15. The Palo Verde trading price closely tracked that of SP15, as there was little congestion on the Palo Verde intertie in any day in September.

The day-ahead price for electricity in SP15 was $34.75/MWh on Saturday, September 6, roughly $3.25 more than in SP15. On September 6, repairs to damage resulting from a fire caused a derate of Path 26 to 2800 MW, causing the day-ahead usage charge in the North-to-South direction to range between $4 and $13/MWh in congested hours. Since this blocked flows from the Northwest into SP15, the day-ahead import price on COI fell to $0.01. By September 7, the path had been restored to full capacity, and loads were sufficiently modest that lines were not congested.

Imports from the Southwest on September 11 and 18 caused day-ahead congestion in the $2-3/MWh range on Palo Verde. On each of these days, the SP15 day-ahead trade price was roughly $2/MWh above that at Palo Verde.

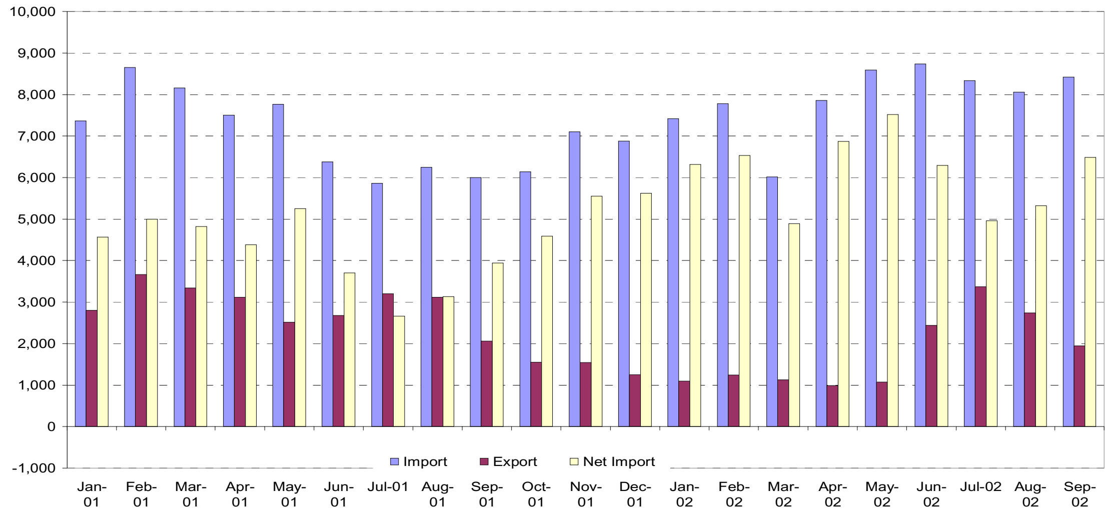
Table 3. Intrazonal Congestion Costs for September

Branch Group	Direction of Congestion	Peak Cong. Pctg.	Off-Peak Cong. Pctg.	All-Hours Cong. Pctg.	Avg. Peak Cong. Price	Avg. Off-Peak Cong. Price	Avg. All-Hours Cong. Price	Total Cong. Cost (DA+HA)
Blythe	Import	0.2%	0.0%	0.1%	$ 1.00		$ 1.00	$ 106.
COI	Import	49.0%	0.4%	33.0%	2.10	$ 1.51	2.10	634,786.
Eldorado	Import	1.0%	0.0%	1.0%	3.00		3.00	45,818.
NOB	Import	42.0%	0.0%	28.0%	0.02		0.02	8,203.
Palo Verde	Import	7.0%	0.0%	5.0%	2.27		2.27	214,782.
Path 15	South-to-North	0.4%	15.0%	5.0%	0.	0.	0.	1.
Path 26	South-to-North	0.0%	0.0%	0.0%				41,400.
Sylmar-AC	Import	6.0%	0.0%	4.0%	72.07		72.07	148,659.
Path 26	North-to-South	6.0%	0.0%	4.0%	3.81		3.81	271,580.

V. Imports and Exports

Net imports of electricity have been particularly brisk, averaging 6,482 MW in September, the third highest monthly average net import volume seen since January 2001, and approximately 1,000 MW higher than the volume seen in August. As suggested in Section IV, these imports flow primarily from the Pacific Northwest and Southwest regions. The increase in net imports into California is actually due to a significant drop in exports over the past few months, as schedules from California to the Southwest to supplement local resources decreased 42 percent between July and September. The following chart shows the ISO's monthly average gross imports, exports, and net imports through September.

Figure 8. Monthly Average Imports and Exports through September



VI. Summary of Market Costs

As noted above, total costs to load of wholesale energy and ancillary services was $899 million, or an average of $44/MWh in September, compared to $43/MWh in August and $44/MWh in July. The average cost index has remained in the range of $39 to $46/MWh since October 2001. Plentiful import supply, low bilateral energy prices, and moderate natural gas prices have helped to control costs in California. The following table shows costs for wholesale energy and AS for 2002 to date, including actuals from CERS through June, and estimates of bilateral purchases at day-ahead hub prices. CERS costs for July and August are estimates; actuals for these months are expected to be available in the October report, to be released in November. Actuals for September will be available in January.

Table 4. Energy Cost Summary by Month for 2002 to Date

	ISO Load (GWh)	Forward Energy (GWh)*	Est Forward Energy Costs (MM$)**	RT Energy Costs (MM$)***	A/S Costs (MM$)****	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
Jan-02	19,356	18,940	$ 737	$ 7	$ 19	$ 744	$ 763	$ 38	$ 0.97	2.5%	$ 39
Feb-02	17,153	16,654	$ 663	$ 7	$ 12	$ 670	$ 682	$ 39	$ 0.68	1.7%	$ 40
Mar-02	18,749	18,282	$ 811	$ 6	$ 9	$ 817	$ 826	$ 44	$ 0.50	1.2%	$ 44
Apr-02	18,511	17,937	$ 742	$ 8	$ 13	$ 750	$ 763	$ 41	$ 0.68	1.7%	$ 41
May-02	19,690	19,031	$ 774	$ 11	$ 15	$ 786	$ 801	$ 40	$ 0.78	2.0%	$ 41
Jun-02	20,232	19,691	$ 786	$ 10	$ 20	$ 796	$ 816	$ 39	$ 0.97	2.5%	$ 40
Jul-02§	22,079	21,319	$ 931	$ 11	$ 23	$ 942	$ 965	$ 43	$ 1.04	2.4%	$ 44
Aug-02§	21,588	20,798	$ 914	$ 8	$ 12	$ 922	$ 935	$ 43	$ 0.58	1.3%	$ 43
Sep-02§	20,498	19,089	$ 885	$ 14	$ 11	$ 899	$ 910	$ 44	$ 0.54	1.2%	$ 44
Total 2002	177,856	171,741	$ 7,243	$ 83	$ 134	$7,326	$ 7,460				
Avg 2002	19,762	19,082	$ 805	$ 9	$ 15	$ 814	$ 829	$ 41	$ 0.75	1.8%	$ 42

* 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
§July, August, and September forward costs (and resulting totals) are estimated. July and August values in October report will include true-up and may differ from values shown here.

VII. Firm Transmission Rights Market

Firm Transmission Rights (FTR) Concentration. No secondary FTR market trades or scheduling coordinator reassignments occurred in September. Hence, the FTR ownership concentrations reported in January-February 2002 report for the 2002-2003 FTR cycle remain unchanged.

FTR scheduling. On some paths, FTRs were used to establish scheduling priority in the day-ahead markets, although rights themselves were not invoked. As shown in the following table, a high percentage of FTRs was scheduled on some path (e.g. 86% on Eldorado, 72% on IID-SCE, 63% on Palo Verde, and 100% on Silver Peak in the import direction). FTRs on those paths are owned mainly by Southern California Edison Company. FTRs on most other paths were primarily used for their financial entitlement to transmission charges.

Table 5. FTR Scheduling in September

	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Schedule	% FTR Schedule
COI Import	658	102	200	150	16%
Eldorado Import	793	678	700	700	86%
IID-SCE Import	600	435	440	440	72%
Mead Import	478	21	145	145	4%
NOB Import	698	4	12	12	1%
Palo Verde Import	1167	732	804	579	63%
Silver Peak Import	10	10	10	10	100%
Victorville Import	926	10	26	26	1%
Mead Export	456	26	178	173	6%
Palo Verde Export	601	10	95	95	2%
Path 26 South-to-North	1566	320	785	513	20%

* only those paths on which 1% or more of FTRs were attached are listed

FTR Revenue per Megawatt. The following table summarizes FTR revenue per MW up to September 2002 in the current FTR cycle. There did not appear any significant changes in FTR revenue from the previous month. COI continues to report the highest FTR revenue per MW among all the branch groups. There was some congestion in both directions on Path 26 in September.

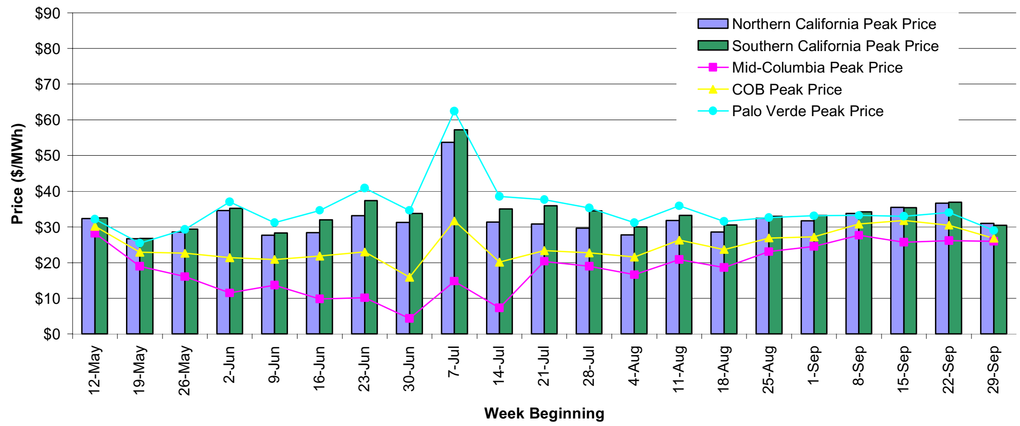
Table 6. FTR Revenue through September

Branch Group		April ($/MW)	May ($/MW)	June ($/MW)	July ($/MW)	Aug ($/MW)	Sep ($/MW)	Cumulative FTR Revenue Up to Sep. 2002 ($/MW)	Pro-rate Annual FTR revenue ($/MW)	FTR Auction Price ($/MW)
COI	Import	1088	888	4129	4278	581	562	11,527	23,053	17,610
Eldorado	Import	268	26	2	10	0	37	343	685	8,432
Mead	Import	19	22	0	0	0	0	41	81	4,488
NOB	Import	13	0	48	472	14	5	553	1,106	5,990
Palo Verde	Import	23	839	0	0	4	86	953	1,905	14,868
Path 26	South-to-North	0	133	370	0	0	25	528	1,056	3,222
Mead	Export	0	0	0	262	31	0	293	586	7,465
Path 26	North-to-South	61	134	125	1703	116	114	2,253	4,506	5,907
Victorville	Export	0	249	724	0	0	0	973	1,947	1,118

VIII. Bilateral Spot Electricity Markets

Varying temperatures between the Southwest and Northwest, in addition to the Path 26 fire, created wide price spreads among Western hubs, with the Palo Verde price $15/MWh higher than the Mid-Columbia price on September 6. Hot weather in the Southwest and cool weather in the Northwest caused Northern California and Northwest prices to range between $21 and $35/MWh, while prices in the Southwest were consistently at the $35 to $37/MWh level during the first week of September. Subsequent increases in cooling demand in the North and deratings on the California-Oregon Intertie (COI) during the second week of September caused Mid-Columbia prices to increase nearly $30/MWh, and COB and Northern California prices to return to $35/MWh. Rising natural gas prices caused slight electricity price increases in all locations except for Mid-Columbia during the third week of the month. Meanwhile, the Mid-Columbia price decreased due to reduced cooling demand and expectations of increased output from Grand Coulee Dam. Continued increases in gas prices and expectations of higher temperatures and demand caused prices to reach their monthly highs on September 23 and 24. California prices exceeded $40/MWh; and Palo Verde, COB, and Mid-Columbia prices hovered around $37, $32, and $26/MWh, respectively. Prices receded by September 27 to the range of $27 to $35/MWh. The following chart shows weekly average spot forward prices through September.

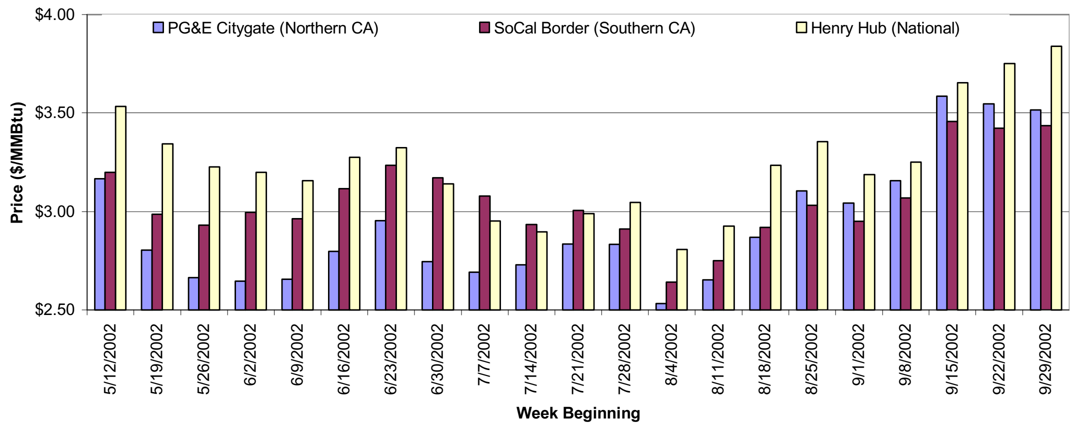
Figure 9. Weekly Average Bilateral Spot Electricity Prices through September



IX. Natural Gas Markets

Natural gas prices through the first half of September were flat, ranging from $3.10 to $3.30/MMBtu at Henry Hub and $2.90 to $3.00/MMBtu at Malin. This price stability was due primarily to high gas storage volumes. Concerns about Tropical Storm Hanna and Hurricane Isidore, however, caused producers to reduce production and evacuate personnel from facilities in Louisiana. Prices increased between September 16 and September 20, and remained within the $3.50-to-$4.00/MMBtu range from September 20 to September 26. As concern for tropical storms receded somewhat, prices at Henry Hub returned to the $3.60/MMBtu level, and California prices returned to the $3.10-to-$3.30/MMBtu range. A high-linepack operational flow order issued by PG&E also helped to moderate prices. The threat of evacuations and production outages due to Hurricane Lili caused prices to spike on September 30, particularly at Henry Hub. Average bid week prices for October were $3.30, $3.31, and $3.35 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 6%, 13%, and 7% from September bid week prices. The following chart shows average weekly gas prices through September.

Figure 10. Weekly Average Gas Prices through September



X. Issues under Review

MD02. DMA staff is in the process of updating monitoring methodologies and software to better observe the effects of Phase 1A of the 2002 Market Redesign (MD02). Some of these efforts include the following:

- Revising indices to better measure market performance under MD02's single-price auction mechanism, and to compare future performance with that under the current regime of separate INC and DEC prices.
- Reviewing of software developed by Potomac Economics to calculate the ISO's Automatic Mitigation Procedures (AMP) price curves.

CPUC Report. DMA staff is assisting in the ISO's review and analysis of a CPUC Report released in September 2002 which examined the outages, bidding and dispatch data during 38 days in the winter of 2000-2001 on which non-firm and firm service interruptions affected load in the ISO Control Area. The CPUC report had concluded that most of California's power blackouts service interruptions need not have occurred.

FERC Refund Proceeding. DMA prepared comments on behalf of the ISO in response to an August 13, 2002 FERC order, in which Commission invited comments and proposals concerning the method for determining the cost of natural gas in calculating the mitigated market clearing price (MMCP) in the ongoing California refund proceeding. This notice was issued in response to a report released by FERC Staff, which set forth significant evidence indicating that the spot market gas price indices used in the refund methodology were artificially inflated during the period relevant to the refund proceeding, and recommended an alternative methodology for calculating the cost of natural gas for purposes of determining refunds. The ISO's comments support the alternative method proposed by FERC Staff, under which the gas price used in calculating the MMCP would be based on spot prices in producing regions of the Southwest United States and Canada, plus a cost-based charge for transportation to California. The ISO's comments recommend guidelines and limitations that should be placed on the ability of sellers to seek to justify gas costs in excess of this proxy price that might be netted from their refund obligation.

Investigations of Market Manipulation. DMA Staff continues to respond to data requests from a variety of state and Federal entities investigating potential manipulation in the wholesale energy markets. Additional results of the ISO's review of practices outlined in Enron memoranda released to the public in March 2002 were provided to FERC and other legal/regulatory entities investigating these practices. DMA staff has also provided testimony to the California State Select Committee to Investigate Price Manipulation in the wholesale market.