Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistant

Date: January 17, 2003

Re: **Market Analysis Report for November and December, 2002**

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

Executive Summary

Phase 1a of the ISO's 2002 Market Redesign (MD02) has been in place since October 30. This increased the $91.87-per-megawatt-hour (MWh) price cap to a damage control bid cap of $250/MWh, and also put into place the Automatic Mitigation Procedure (AMP). Meanwhile, natural gas prices have risen steadily over the past few months, peaking above $5 per million British Thermal Units (MMBtu) in December. These factors have all contributed to an increase in electricity prices. The market-clearing price (MCP) for real-time incremental (INC) energy procured through the ISO's Balancing Energy Ex-Post Price auction market (the BEEP Stack) averaged $64.70 and $62.38 per megawatt-hour (MWh) in November and December, respectively, compared to $59.62/MWh in October. The BEEP price for decremental (DEC) energy averaged $14.17/MWh in November and $15.23/MWh in December, up substantially from the $10.08 level seen in October.

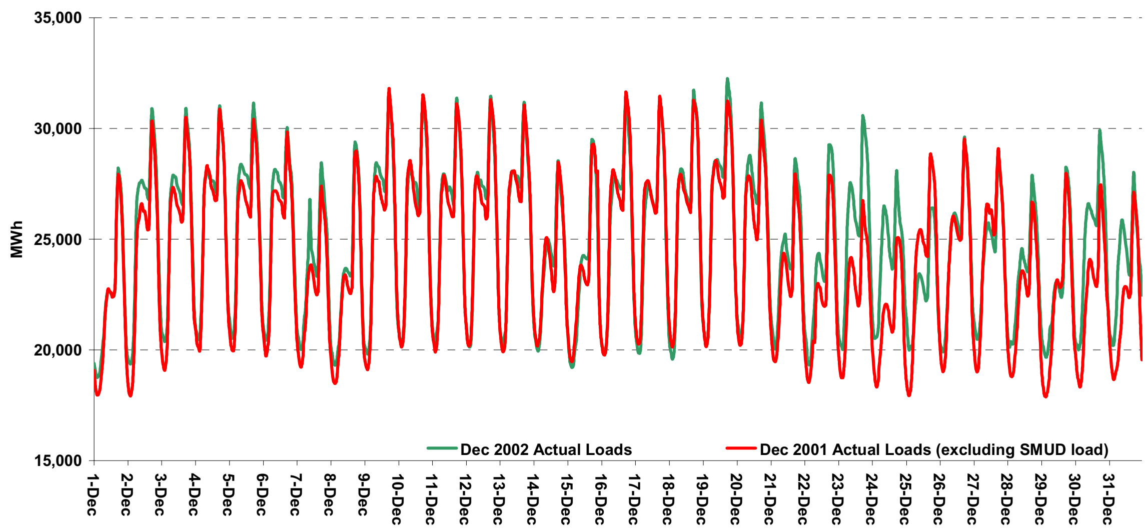
The new AMP mitigation measures have yet to be triggered. Since the inception of Phase 1a, AMP has detected Conduct Test failures in at least 36 hours in November or December. None of these incidents resulted in failures of the Impact Test. Please see the section on real-time markets later in this document for a detailed discussion of AMP.

Beginning January 1, the utility distribution companies (UDCs) began procuring their own net-short forward-scheduled energy requirements. The Department of Water Resources' California Energy Resources Scheduler (CERS) is no longer procuring electricity on the utilities' behalf, but will provide the utilities with a guarantee of credit upon which they can make their own purchases. Also on January 1, the ISO assumed operational control of transmission lines belonging to four new municipal Participating Transmission Owners (PTOs), extending ISO control over several new branch groups.

I. Market Trends in November and December 2002

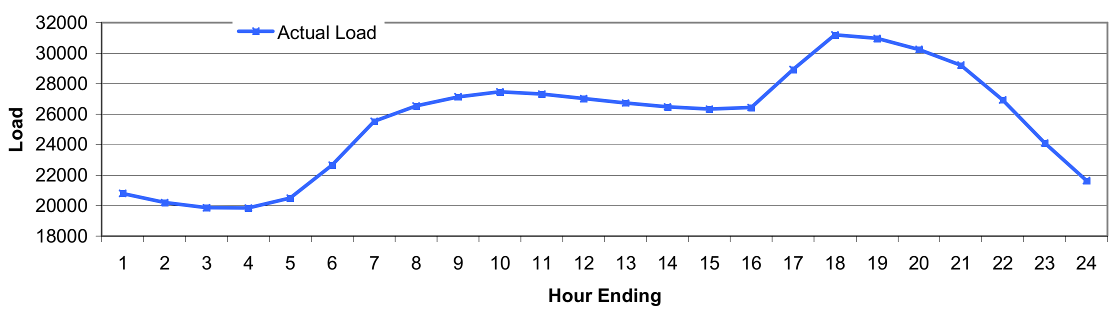
Load averaged 24,623 MW in November 2002, up 4.4 percent since November 2001. In December 2002, load averaged 24,879 MW, up 2.6 percent since December 2001. This is due in part to inclement weather, and also to the Christmas and New Year holidays falling midweek, leading to higher loads on days just before and after the holidays. The following chart compares loads in 2002 with loads in 2001.

Figure 1. Hourly Load Comparison: December 2001 and 2002



As is typical in the winter months, the evening ramp has presented difficulties for scheduling coordinators and ISO operators. This time of year, operators typically see an increase of load of approximately 4,500 MW, or 14.4 percent of the daily peak load, between 4:00 p.m. and 6:00 p.m., just before that peak in the evening, as shown in the following chart.

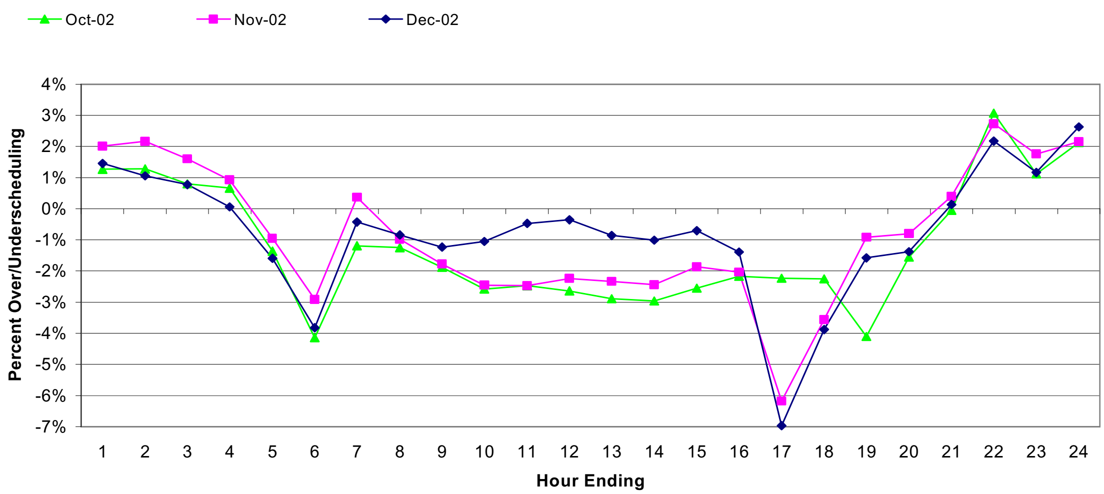
Figure 2. Typical Winter ISO Load Profile



With the exception of the jump in load between 4:00 and 6:00 p.m. (HE 17:00 and 18:00), due to the seasonal shift in load toward evening hours, scheduling deviations have decreased in each month since October. In particular, scheduled energy was within 2 percent of load on average in

19 hours per day, compared with 13 hours in November and 11 hours in October. Scheduling deviations tend to follow system loads closely, with the most significant underscheduling occurring during the steep evening ramp, as can be seen by comparing figures 2 and 3. Similarly, overscheduling tends to occur as loads drop off in the late evening and early morning hours. The following chart shows hourly profiles of scheduling deviations from October through December.

Figure 3. Three-Month Hourly Profile of Deviations of Forward Schedules from Actual Load



II. Real-Time Market

Automatic Mitigation Procedure. The Automatic Mitigation Procedure (AMP) has been in effect since October 30, 2002. AMP is an automated routine that compares actual BEEP energy bids with unit-specific *reference levels.* In hours that the BEEP MCP is expected to exceed $91.87, a unit that bids its energy at least $100 or 200% above its reference price is said to fail the AMP *Conduct Test*. The BEEP algorithm is re-run with the unit's bids substituted by its reference prices as bids. If this re-run of the algorithm results in a change of $50 or 200% in the BEEP MCP, the unit is said to have failed the *Impact Test*. In this case, the unit's bids would be mitigated automatically to its reference prices. For more details, please see the AMP white paper at www.caiso.com in the Stakeholder Processes MD02 Phase 1a Design Concepts section.

The Department of Market Analysis (DMA) monitors several indices to assess the performance of AMP mitigation. These include the frequencies of AMP conduct and impact test failures by entire market, as well as by generation type and ownership class. In addition, DMA tracks trends in average reference prices, which is an indicator of overall bidding trends. To date, the AMP mitigation measures have not been significantly tested, as favorable supply conditions relative to demand have generally kept prices at manageable levels. However, a series of price spikes during November and December can be used as a barometer to measure the probable performance of AMP during prolonged price spikes.

AMP mitigation was not triggered during any of the price spikes that occurred in November and December. While units that set the MCP during certain price spikes bid significantly in excess of their reference levels, this behavior was not sufficient to cause the bid to fail the Conduct Test of $100/MWh or 200 percent above their reference level. In fact, in several intervals in November and December during which the MCP was in excess of $100/MWh, units that set the MCP were able to sell at prices significantly above their marginal operating costs without failing the Conduct Test. This is due either to the unit having a reference price that is set significantly above its marginal operating costs, or to a unit having higher costs that, under the current rules, is able to bid up to $100 above its reference price without failing the AMP Conduct Test. Given the current thresholds, AMP mitigation will likely only be triggered during extreme price spikes.

Since October 30, there has not been a single failure of the Impact Test. However, there have been hours in which units have failed the Conduct Test but did not have a material impact on the MCP. Certain units in particular repeatedly have failed the Conduct test. These generally have been municipal-owned gas turbines (Muni), qualifying facilities (QF), and hydroelectric units. Furthermore, fewer than ten units account for at least 75 percent of all violations. While some such units bid excessively high prices, others fail the Conduct Test because they have very low bid-based reference levels, possibly because they had bid at low prices in order to be accepted for dispatch in the market. Units that are true price takes and submit zero price bids do not have those bids included in their reference level calculation.

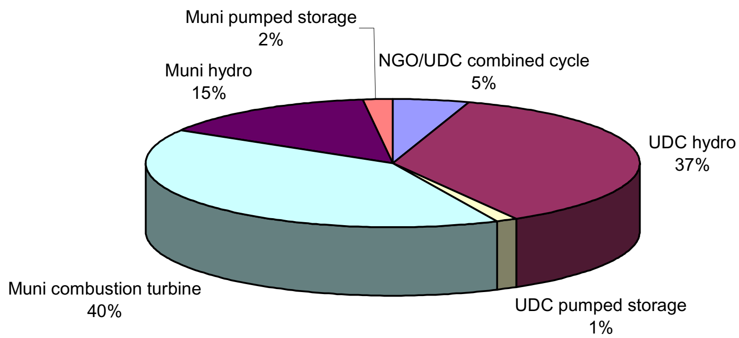
For this and other reasons, DMA does not necessarily infer that repeated failures of the Conduct Test are indicative of an attempt to exercise market power. The table below shows the number of hours of failures in each day since October 30. The pie chart that follows shows the shares by generation and ownership classes of all AMP Conduct Test failures in December.

Table 1. Hours per Day with AMP Conduct Test Failures

Day	No. of Hours
31 Oct	1
1 Nov	1
2 Nov	1
10 Nov	2
11 Nov	3
19 Nov	1
27 Nov	3
4 Dec	1
12 Dec	1
15 Dec	7
16 Dec	12
17 Dec	2
24 Dec	1

[1] A Conduct Test failure can occur in any hour, and by any unit. DMA counts failures as unit-hours. That is, units' contributions to the volume of failures are weighted by the number of hours in which they fail.

Figure 4. Shares of AMP Conduct Test Failures by Generation and Ownership Classes in December[2]



Because they are based primarily on 90-day rolling averages of accepted bids, reference prices serve as indicators of bidding trends. Reference prices for thermal units are adjusted to account for changes in the price of natural gas. While reference prices on average have been increasing, the increase in gas-fired units' prices can be explained largely by the rise in the cost of natural gas. The chart below shows average reference levels for gas-fired thermal generators, normalized to October gas prices, and suggests that reference prices generally are stable or decreasing, when controlling for the variation in gas prices.[3] The chart that follows shows non-normalized average reference levels for other generation types.

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[2] A Conduct Test failure can occur in any hour, and by any unit. DMA counts failures as unit-hours. That is, units' contributions to the volume of failures are weighted by the number of hours in which they fail.

[3] Since each reference price is based upon a rolling average of accepted bids, DMA observes trends in reference prices by comparing individual hour snapshots across time. The price is taken by volume-weighted averaging of all reference prices for each generation class in HE 16 of the third Wednesday of the month. This average price per MWh is then multiplied by the ratio of the October 2002 gas price to the price of the quoted month.

Figure 5. Average Reference Levels for Gas-Fired Generators Normalized to October 2002 Gas Prices

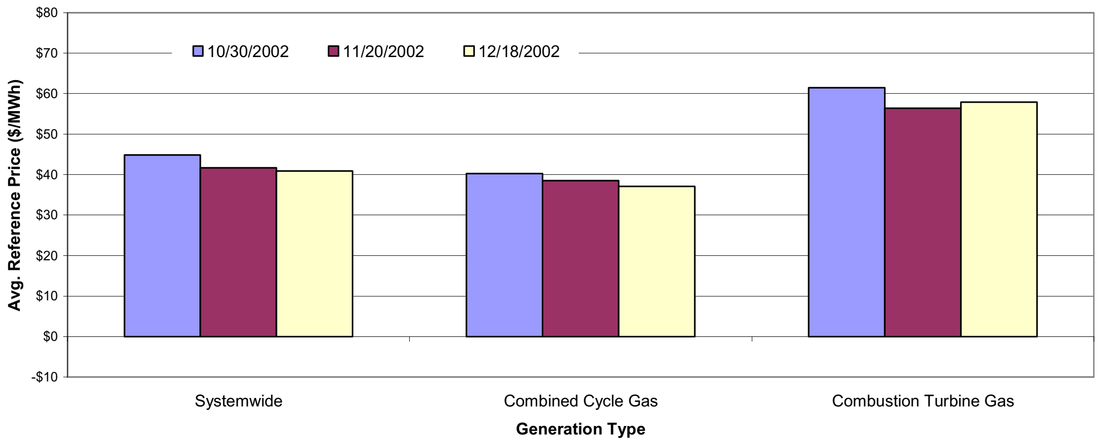
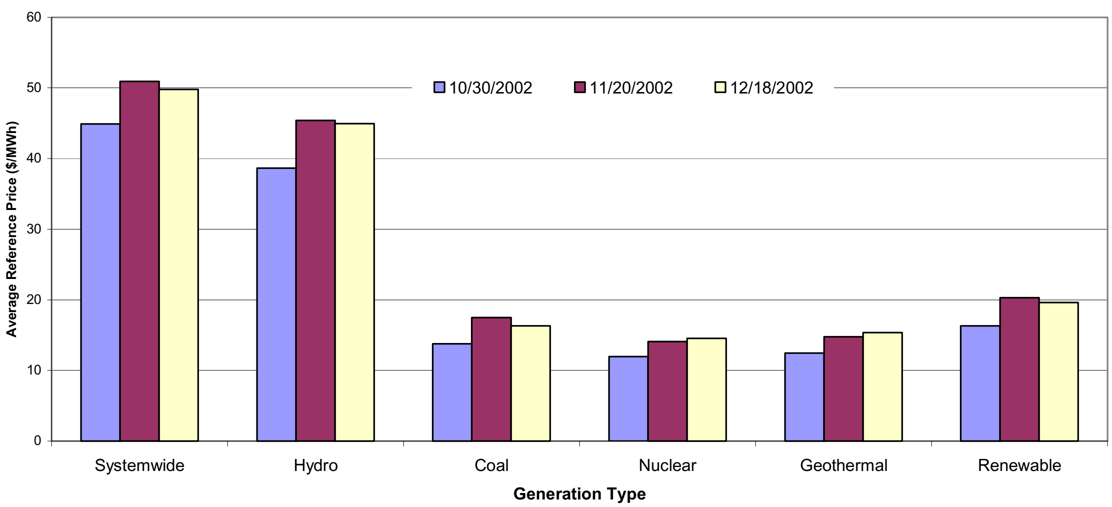
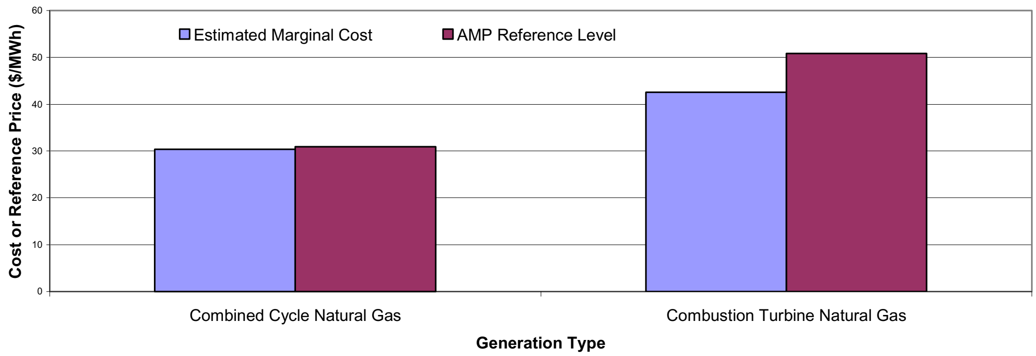


Figure 6. Average Absolute Reference Levels for Other Generation Types (Not Adjusted for Gas Price Variation)



Thus far, reference prices overall have been similar to marginal costs. The following chart compares average actual marginal operating costs to average reference levels for thermal units by generation type.

Figure 7. Average Cost vs. Average Reference Price: December 31, 2002



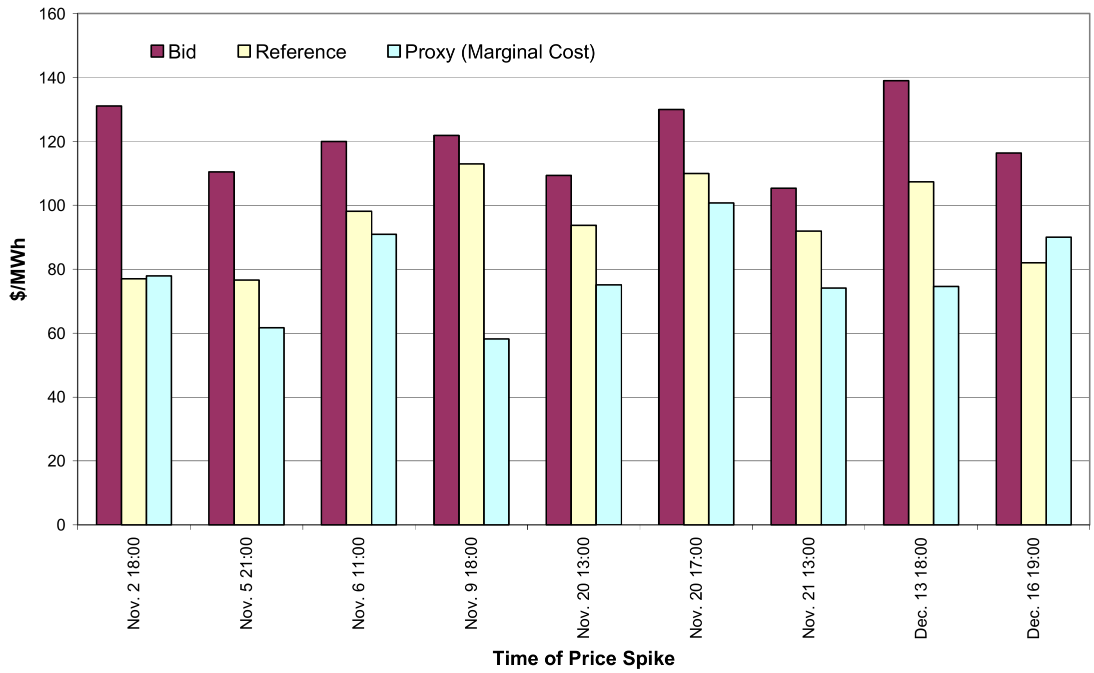
The Department of Market Analysis (DMA) will continue to monitor the efficacy of AMP mitigation in mitigating instances of market power.

Price Spikes. The increase in average BEEP INC prices can be attributed in part to price spikes in approximately 53 ten-minute intervals in November, of which three contiguous hours each occurred on the evenings of November 20 and December 16.[4] The total cumulative cost of all such spikes was approximately $1.4 million, with a relatively high average interval procurement of 218 MWh, at an average price of $119/MWh. This cost is approximately $624,000 (or $54/MWh) greater than if the same volume had been procured in those intervals at a typical peak-hour price of $65/MWh. All of the spikes occurred in SP15, usually with a split stack due to congestion on Path 15 or Path 26, and most can be attributed to import limitations during high loads as specified in the Southern California Import Transmission Nomogram (SCIT).

None of the bids that caused spikes in November or December failed the AMP Conduct Test. A lower AMP Conduct threshold level of $50 or 100% above the reference level would have caused the MCP-setting bid to have failed the Conduct Test in at least one instance. The MCP setter during the spike on November 2 offered energy at a price greater than $50/MWh above the unit's reference curve, but not high enough to trigger the existing threshold of $100/MWh or 200% above the reference curve. In one other instance, a cost-based Conduct threshold would have caused the MCP-setting bid to have failed the Conduct Test. During spikes on November 2 and 9, the MCP was at least $50 or 100% above the MCP setters' marginal cost curves (used to create proxy bids for units subject to the Must-Offer Requirement). The following chart compares MCP-setting bids during price spikes with reference prices and marginal costs associated with the bids that set the MCP.

[4] For this analysis, DMA has defined a price spike as an incremental MCP above $100/MWh.

Figure 8. MCP-Setting Bid Prices, with associated Reference Prices and Proxy Bids



In December, there were two spikes in the price of incremental energy, on December 13 and 16. On December 13, a fast evening ramp forced operators to dispatch deep into the BEEP stack between 5:00 and 6:00 p.m. This caused prices to stay above $100/MWh for 8 intervals, peaking at $139/MWh. On December 16, with Midway-Vincent line 1 already scheduled out, a storm blew down several towers supporting the Midway-Vincent line 3, curtailing Path 26 to 500 MW. This congestion necessitated that the BEEP Stack be split between northern and southern California causing prices in Southern California to spike for five hours, peaking at $140.54/MWh.

The BEEP MCP was set by a particular thermal peaker resource in approximately 29 intervals between November and December in which the MCP was at least $100/MWh. While this high-cost unit's bids routinely were high enough to cause the MCP to rise to these levels, its reference price was sufficiently high that the bids remained below the AMP Conduct Test thresholds.[5]

The following charts show BEEP interval prices for November and December.

[5] If the threshold had been set at the minimum of $50 or 100% over the reference price, as proposed by ISO Staff in its May 1 filing, bids at these prices by this resource would have failed the Conduct Test. However, this is only an hypothetical situation. A different mitigation regime necessarily would result in different bidding behavior.

Figure 9a. BEEP SP15 Ten-minute Interval Prices in November

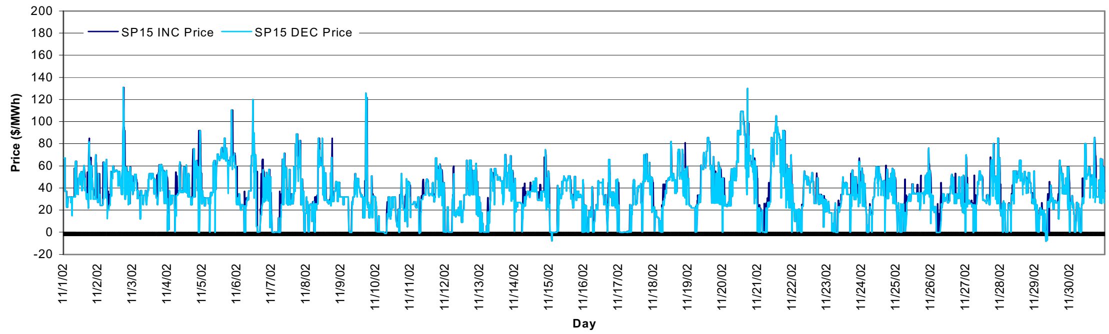
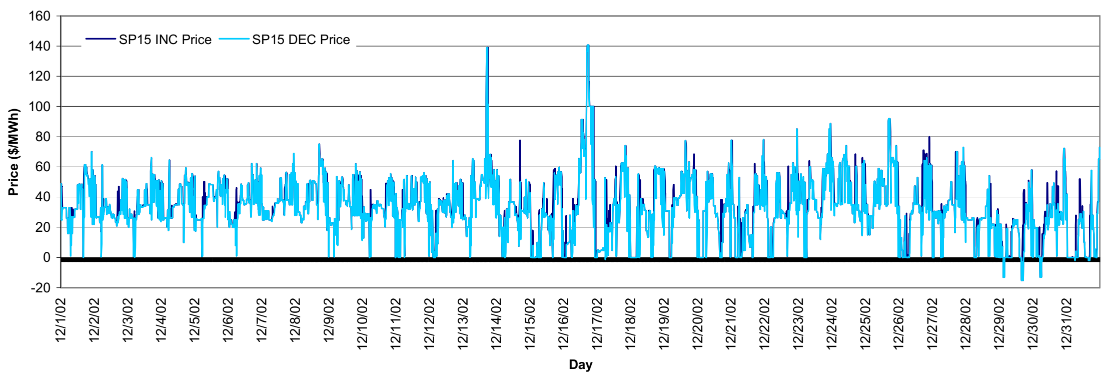


Figure 9b. BEEP SP15 Ten-minute Interval Prices in December



Out-of-Market procurement information was not available for November or December at the time of writing.

BEEP Prices. Average BEEP prices have increased since October, due largely to a higher damage control bid cap and higher natural gas prices. The average BEEP INC prices for November and December were $64.70 and $62.38/MWh, respectively, compared with $59.62/MWh in October. The DEC price, which suppliers pay to the ISO for decreasing output when scheduled energy exceeds actual load, averaged $14.17 and $15.23/MWh in November and December, respectively, compared with $10.08/MWh in October. The following tables show BEEP INC and DEC prices in November and December.

Table 2a. BEEP Average Prices and Total Volume for November

	Avg. As-Bid Price and Total Volume		Avg. BEEP Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	Inc	Dec	
Peak	No Procurement	No Procurement	$65.61	$16.24	26,421 MW
	*	*	126 GWh	104 GWh	1.0%
Off-Peak	No Procurement	No Procurement	$58.89	$11.68	21,027 MW
	*	*	20 GWh	87 GWh	-0.9%
All Hours	No Procurement	No Procurement	$64.70	$14.17	24,623 MW
	*	*	146 GWh	191 GWh	0.9%

Table 2b. BEEP Average Prices and Total Volume for December

	Avg. As-Bid Price and Total Volume		Avg. BEEP Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	Inc	Dec	
Peak	No Procurement	No Procurement	$63.96	$17.52	26,690 MW
	*	*	79 GWh	154 GWh	1.0%
Off-Peak	No Procurement	No Procurement	$58.52	$10.73	21,256 MW
	*	*	32 GWh	79 GWh	-0.2%
All Hours	No Procurement	No Procurement	$62.38	$15.23	24,879 MW
	*	*	111 GWh	233 GWh	0.8%

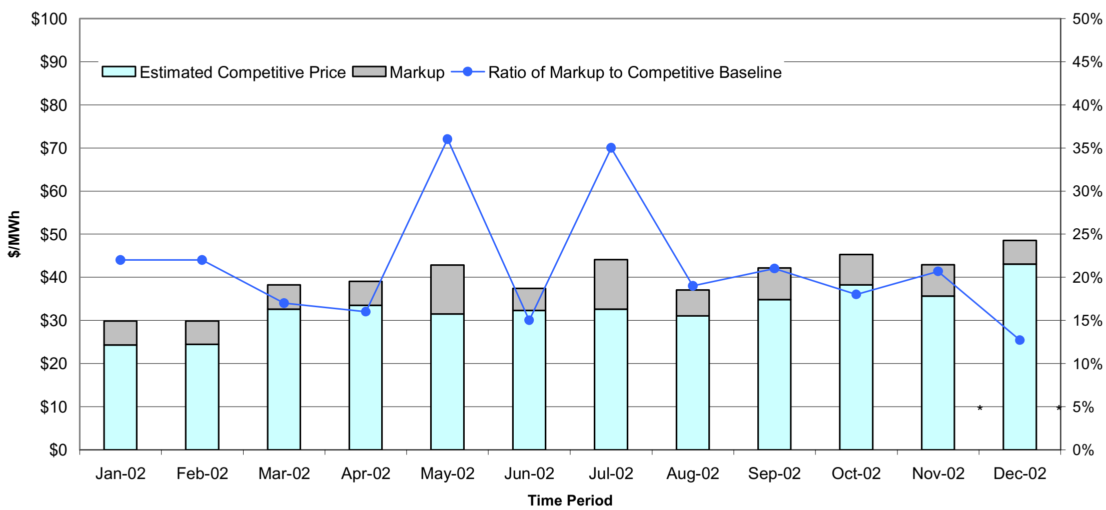
Market Power. Market power is often measured by comparing the price paid for energy to an estimate of the price that would exist under competitive conditions. The Department of Market Analysis (DMA) tracks several such indices, all of which are calculated as the ratio of the markup included in the average 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 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.

Since November, market power has not been a significant factor in short-term energy prices. The Short-Term Markup Index indicates that actual market costs have been reasonably close to estimated competitive baseline costs. The following chart shows the short-term markup, using CERS actual short-term energy procurement cost through October, and estimates for November and December. These estimates are subject to change as actual transaction data is made available by CERS.

Figure 10. Price-to-Cost Markup in Short-Term Energy in 2002[6]



III. Ancillary Services (AS)

Day-ahead upward regulation service prices averaged $11.30 and $10.30/MWh in November and December, respectively, compared to $14.51/MWh in October. Day-ahead downward regulation service prices averaged $13.03 and $10.60/MWh in November and December, respectively, compared to $14.64/MWh in October. Spinning reserves day-ahead prices averaged $2.86 and $5.12/MWh in November and December, respectively, compared to $3.08/MWh in October. Non-spinning reserves averaged $1.65 and $2.44 in November and December, respectively, compared with $1.57 in October. Replacement reserves averaged $1.31/MWh in both November and December, compared to $1.15 in October. Volumes in all services have varied little since October. The following tables show average ancillary service prices and volumes by market in November and December.

[6] November and December markups are estimated.

Table 3a. Ancillary Services Prices and Volumes by Market for November

	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	$ 11.30	$ 11.94	$ 11.34	336	24	93%
Regulation Down	$ 13.03	$ 12.19	$ 12.96	371	34	91%
Spin	$ 2.86	$ 3.71	$ 2.91	650	40	94%
Non-Spin	$ 1.65	$ 2.27	$ 1.68	672	37	94%
Replacement	$ 1.31	$ 1.91	$ 1.32	23	*	97%

Table 3b. Ancillary Services Prices and Volumes by Market for December

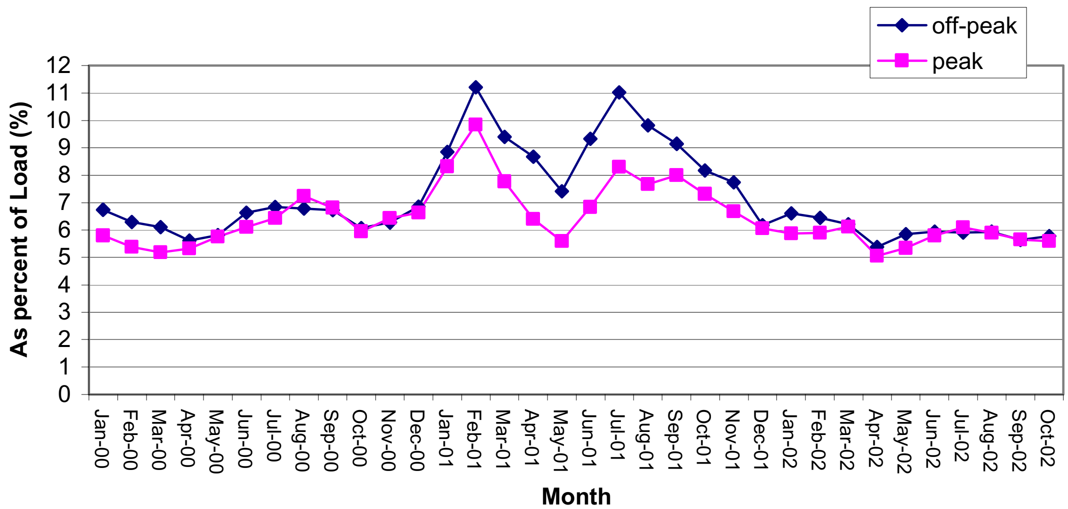
	Day-Ahead Market	Hour-Ahead Market	Quantity Weighted Price	Average Hourly MW Day Ahead	Average Hourly MW Hour Ahead	Percent Purchased in Day Ahead
Regulation Up	$ 10.30	$ 10.04	$ 10.28	346	29	92%
Regulation Down	$ 10.60	$ 11.07	$ 10.65	355	41	89%
Spin	$ 5.12	$ 3.77	$ 5.07	679	24	96%
Non-Spin	$ 2.44	$ 2.14	$ 2.44	690	12	98%
Replacement	$ 1.31	$ 1.99	$ 1.32	21	*	98%

DMA has observed several price spikes in many of the AS markets and is in the process of investigating them. For example, on December 31, HE 18:00, the ISO procured 190 MW of spinning reserves in the day-ahead market at $250/MW, which could not be sufficiently mitigated through the Rational Buyer purchasing algorithm. DMA is currently analyzing bid sufficiency and other causes as possible reasons for the price spikes in these markets.

DMA has completed a review of ISO Ancillary Service procurement practices in response to a market participant inquiry. The participant expressed concern that the ISO has lowered the volume of Ancillary Services it procures since the summer of 2001 as a result of FERC's Must Offer Order of June 19, 2001.

In reviewing the procurement data, DMA found that the ISO's changes in purchase volumes of operating reserves was not due to the must offer requirement. Procurement levels as a percentage of load in 2002 were consistent with those in 2000. In 2001, ISO operators had altered their purchasing patterns in response to changing levels of AS self-provision. Beginning approximately February 2001, scheduling coordinators began self-providing AS at a rate higher than that seen previously. Over time, the ISO Operators gained confidence in the extent of actual self-provision through observation and experience with the market, and then were able to adjust market purchasing levels accordingly. While there were changes in operating reserve requirements (and procurements) during 2001, the ISO's purchases of operating reserves were consistent on a percentage-of-load basis before and after 2001, as shown in the following chart.

Figure 11. Operating Reserves Procurement (Self-Provision and Purchases) as a Percentage of Load



The ISO's Regulation services requirement was also consistent, as a percentage of load, before and after the Must Offer Obligation, but was lowered prior to Summer 2002. The reduction of overall Regulation procurement at that time can be attributed to better management of purchased and self-provided Regulation services to achieve NERC control performance standards. In particular, the reduction is not due to the use of unloaded capacity of must-offer resources.

IV. Interzonal Congestion

Of the $2.0 million in Interzonal congestion costs incurred in November, over $1.6 million was incurred in the day-ahead market on two key paths importing into Southern California. $944,000 was incurred on Eldorado, almost entirely in the day ahead market, due to a forced outage on November 13-15 causing a derate to 536 MW. Palo Verde incurred approximately $700,000 of import congestion as schedules were near the path limit for most of the month, and exceeded the limit on November 2-4 and 14.

In December, Interzonal congestion totaled $1.6 million of which nearly $1.1 million can also be attribute to imports on Palo Verde, during derates to 1063 MW on December 7, 9, and 19, in both the day-ahead and hour-ahead markets. The derate on December 7 was unusually complicated due to maintenance during SCIT congestion. Installation of new combustion turbines at Devers necessitated the derate on December 9. The day-ahead congestion price spiked to $140/MWh during the December 19 derate, again due to SCIT congestion. Another $295,000 was incurred on Path 26, in the North-to-South direction, during the derate to 500 MW caused by the downed tower supporting Midway-Vincent Line 3 on December 16-19. These costs were spread across the day-ahead and hour-ahead markets.

The following tables show day-ahead Interzonal congestion for November and December.

Table 4a. Interzonal Day-Ahead Congestion Frequencies and Prices and Total Congestion Costs for November

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%	0%	0%				$ 385
COI	Import	3%	0%	2%	$ 0.37		$ 0.37	16,310
Eldorado	Import	4%	2%	3%	73.16	$45.49	67.99	944,201
IID-SCE	Import	0%	0%	0%				991
Mead	Import	0%	0%	0%				103,570
NOB	Import	3%	0%	2%	0.07		0.07	1,924
Palo Verde	Import	11%	5%	9%	6.03	2.50	5.38	769,504
Path 15	South-to-North	0%	7%	2%		0.	0.	1,570
Path 26	South-to-North	0%	5%	1%		3.04	3.04	37,630
Sylmar (AC)	Import	1%	0%	1%	60.00		60.00	25,213
Path 15	North-to-South	1%	0%	1%	1.39		1.39	8,400
Path 26	North-to-South	3%	0%	2%	2.08		2.08	73,161

Table 4b. Interzonal Day-Ahead Congestion Frequencies and Prices and Total Congestion Costs for December

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%	0%	0%				$ 303
COI	Import	0%	0%	0%				823
Eldorado	Import	0%	0%	0%				45,286
Mead	Import	1%	0%	1%	$ 1.40		$ 1.40	16,865
NOB	Import	0%	0%	0%				49,308
Palo Verde	Import	13%	1%	9%	9.52	$ 66.02	10.55	1,078,775
Path 15	South-to-North	1%	39%	14%				7,585
Path 26	South-to-North	0%	2%	1%		2.17	2.17	39,226
Sylmar-AC	Import	0%	3%	1%		99.93	99.93	82,731
Path 26	North-to-South	4%	0%	2%	26.07		26.07	295,008
Summit	Export	3%	3%	3%	30.00	30.00	30.00	10,822

V. Firm Transmission Rights Market

FTR scheduling. On some paths, FTRs were used to establish scheduling priority in the day-ahead markets. As shown in the following table, a high percentage of FTRs were scheduled on certain paths (in November, for example, 87% on Eldorado, 73% on IID-SCE, 62% on Paloverde, and 92% on Silver Peak, in the import direction). FTRs on those paths are mainly owned by Southern California Edison Company (SCE1). DMA has observed that the percentage of FTRs scheduled on Eldorado in the import direction decreased from 87% in November to 49% in December, suggesting that FTRs were more frequently used to hedge against congestion costs in November, and were used to earn revenues outright in December.

Table 5. FTR Scheduling Statistics in November 2002

	MW FTR Auctioned – Imp	Avg. MW FTR Sch. - Imp	Max MW FTR Sch. - Imp	Max Single SC FTR Schedule	% FTR Schedule - Imp
COI _BG	678	81	225	175	12%
ELDORADO _BG	793	691	700	700	87%
IID-SCE _BG	600	436	448	448	73%
MEAD _BG	522	145	270	170	28%
NOB _BG	734	43	200	200	6%
PALOVRDE _BG	1192	734	804	579	62%
SILVERPK _BG	10	9	10	10	92%
VICTVL _BG	926	19	55	55	2%

	MW FTR Auctioned – Exp	Avg. MW FTR Sch. - Exp	Max MW FTR Sch. - Exp	Max Single SC FTR Sch. - Exp	% FTR Schedule - Exp
PATH26 _BG	1586	176	572	470	11%

Table 6. FTR Scheduling Statistics in December 2002

	MW FTR Auctioned - Imp	Avg. MW FTR Sch. - Imp	Max MW FTR Sch. - Imp	Max Single SC FTR Schedule	% FTR Schedule - Imp
COI _BG	678	20	75	50	3%
ELDORADO _BG	793	386	700	700	49%
IID-SCE _BG	600	409	460	460	68%
MEAD _BG	522	63	182	145	12%
PALOVRDE _BG	1192	821	929	579	69%
SILVERPK _BG	10	9	10	10	92%
VICTVL _BG	926	15	51	51	2%

	MW FTR Auctioned - Exp	Avg. MW FTR Sch. - Exp	Max MW FTR Sch. - Exp	Max Single SC FTR Sch. - Exp	% FTR Schedule - Exp
PATH26 _BG	1586	294	677	500	19%

* 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 December 2002 in the current FTR cycle. Compared with the summer months, the FTR revenue on COI has decreased significantly in November and December. FTR revenue on the Eldorado line in the import direction was high in November and reported the highest FTR revenue per MW among all branch groups. There was also congestion in both directions on Path 26 in November and December. Finally, there was a significant increase in FTR revenue increase on Palo Verde in the import direction in December, due to a relatively high congestion frequency during peak hours.

Table 8. FTR Revenue Per MW($/MW)

Branch Group	Direction	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Cumm Net REV	Pro Rated Annual NET Rev
COI	IMPORT	1,088	888	4,129	4,278	581	562	153	15	0	11,695	15,594
ELDORADO	IMPORT	268	26	2	10	0	37	1,255	1,178	38	2,813	3,751
IID-SCE	IMPORT	0	0	0	0	0	0	0	2	0	2	2
MEAD	IMPORT	19	22	0	0	0	0	97	166	23	327	436
NOB	IMPORT	13	0	48	472	14	5	32	1	31	618	824
PALOVRDE	IMPORT	23	839	0	0	4	86	226	376	887	2,442	3,255
PATH26	IMPORT	0	133	370	0	0	25	28	44	31	631	842
MEAD	EXPORT	0	0	0	262	31	0	0	0	0	293	391
PATH26	EXPORT	61	134	125	1,703	116	114	23	35	178	2,489	3,319
VICTVL	EXPORT	0	249	724	0	0	0	0	0	0	973	1,298

* Pro-rated Annual FTR revenue is estimated based on the actual FTR revenue collected in this FTR cycle and assuming that FTRs would collect same rate of revenue in the remaining months of this FTR cycle

VI. Total Wholesale Energy Costs

The cost of wholesale energy and ancillary services delivered in the ISO Control Area averaged $49/MWh in both November and December 2002, compared to $44 and $43/MWh for November and December 2001, respectively. The $49/MWh level is the highest seen since September 2001. Average costs have been trending upward in the fourth quarter of 2002. Real-time costs have been low in December due to the high proportion of decremental energy in the real-time market, which offsets incremental energy costs.

Total wholesale energy costs for 2002 were approximately $10 billion, or an average of $43/MWh, compared to the 2001 level of $27 billion, or $118/MWh. Total wholesale energy costs remain above the 1999 level of approximately $7.4 billion, or $33/MWh.

The following tables show monthly energy costs for 2002, and annual energy costs since 1998.

Table 9. Wholesale Energy Costs for 2002

	ISO Load (GWh)	Forward Energy (GWh)*	Est Forward Energy Costs (MM$)**	RT Energy Costs (MM$)***	A/S Costs (MM$)****	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of RT INC Energy ($/MWh)	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	$ 45	$ 38	$ 0.97	2.5%	$ 39
Feb-02	17,153	16,654	$ 663	$ 7	$ 12	$ 670	$ 682	$ 45	$ 39	$ 0.68	1.7%	$ 40
Mar-02	18,749	18,282	$ 811	$ 6	$ 9	$ 817	$ 826	$ 52	$ 44	$ 0.50	1.2%	$ 44
Apr-02	18,511	17,937	$ 742	$ 8	$ 13	$ 750	$ 763	$ 53	$ 41	$ 0.68	1.7%	$ 41
May-02	19,690	19,031	$ 774	$ 11	$ 15	$ 786	$ 801	$ 54	$ 40	$ 0.78	2.0%	$ 41
Jun-02	20,232	19,691	$ 786	$ 10	$ 20	$ 796	$ 816	$ 52	$ 39	$ 0.97	2.5%	$ 40
Jul-02	22,079	21,319	$ 931	$ 11	$ 23	$ 942	$ 965	$ 51	$ 43	$ 1.04	2.4%	$ 44
Aug-02	21,588	20,798	$ 914	$ 8	$ 12	$ 923	$ 935	$ 47	$ 43	$ 0.58	1.3%	$ 43
Sep-02	20,498	19,089	$ 878	$ 15	$ 11	$ 893	$ 904	$ 58	$ 44	$ 0.54	1.2%	$ 44
Oct-02	18,677	17,682	$ 856	$ 4	$ 11	$ 860	$ 871	$ 60	$ 46	$ 0.59	1.3%	$ 47
Nov-02	16,967	16,839	$ 812	$ 7	$ 9	$ 819	$ 828	$ 66	$ 48	$ 0.55	1.1%	$ 49
Dec-02	18,510	17,608	$ 897	$ 3	$ 10	$ 901	$ 911	$ 62	$ 49	$ 0.56	1.1%	$ 49
Total 2002	232,011	223,870	$ 9,802	$ 99	$ 165	$9,900	$10,065					
Avg 2002	19,334	18,656	$ 817	$ 8	$ 14	$ 825	$ 839	$ 53	$ 43	$ 0.70	1.7%	$ 43

***** 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

November and December forward costs (and resulting totals) are estimated. Values in March report will include true-up and may differ from values shown here.

Table 10. Annual Wholesale Energy Costs – April 1999 through December 2002

	ISO Load (GWh)	Est Forward Energy Costs (MM$)*	RT Energy Costs (MM$)**	A/S Costs (MM$)***	Total Energy Costs (MM$)	Total Costs of Energy and A/S (MM$)	Avg Cost of Energy ($/MWh)	A/S Cost ($/MWh Load)	A/S % of Energy Cost	Avg. Cost of Energy & A/S ($/MWh Load)
Total 2002	232,011	$ 9,802	$ 99	$ 164	$ 9,900	$ 10,065				
Avg 2002	19,334	$ 817	$ 8	$ 14	$ 825	$ 839	$ 43	$ 0.70	1.7%	$ 43
Total 2001	227,024	$ 21,248	$ 4,162	$ 1,346.09	$ 25,410	$ 26,756				
Avg 2001	18,919	$ 1,771	$ 347	$ 112	$ 2,117	$ 2,230	$ 115	$ 6.07	5.3%	$ 118
Total 2000	237,543	$ 22,890	$ 2,877	$ 1,720	$ 25,373	$ 27,083				
Avg 2000	19,795	$ 1,907	$ 240	$ 143	$ 2,114	$ 2,257	$ 107	$ 7.24	6.8%	$ 114
Total 1999	227,533	$ 6,848	$ 180	$ 404	$ 7,028	$ 7,432				
Avg 1999	18,961	$ 571	$ 15	$ 34	$ 586	$ 619	$ 31	$ 1.78	5.7%	$ 33
1998 (9mo)	169,239	$ 4,704	$ 209	$ 638	$ 4,913	$ 5,551				
Avg 1998	18,804	$ 523	$ 23	$ 71	$ 546	$ 617	$ 29	$ 3.77	13.0%	$ 33

1998-2000:

* Forward costs include estimated PX and bilateral energy costs.

Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.

Estimated Bilateral Energy Cost based on the difference between hour ahead schedules and PX quantities, valued at PX prices.

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

2001 and 2002:

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

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

All years:

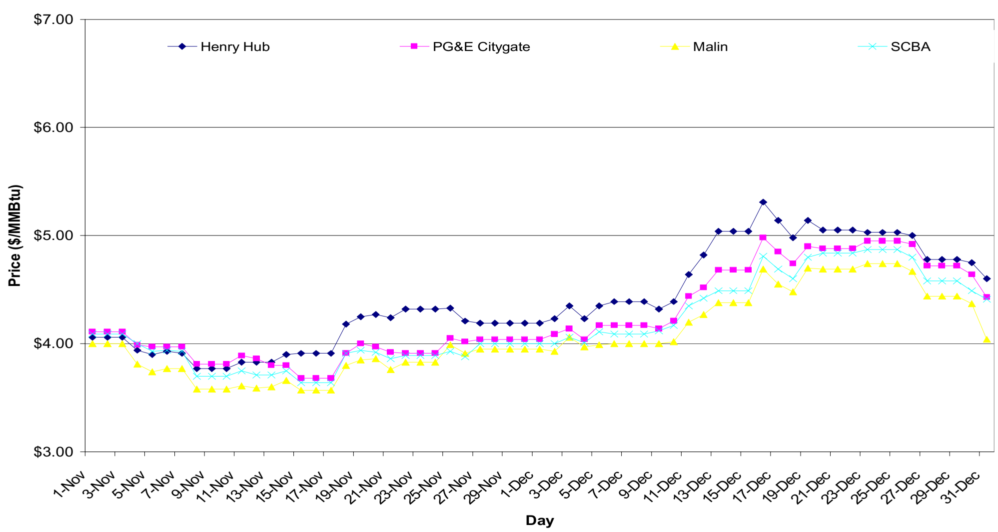
******* Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund

VII. Natural Gas Markets

While short-term variations continue to occur in the natural gas markets, average natural gas prices have increased steadily over the past several months to $5/MMBtu or more in December. Moderate temperatures through much of the country weakened natural gas prices through the first half of November. A cold front moving through the Northeast triggered a sharp increase in heating demand around 17 November, and caused Henry Hub prices to increase past the $4/MMBtu mark to roughly $4.20/MMBtu, separating from California prices by $0.20/MMBtu. As cold weather moved into the West, that spread decreased to $0.05/MMBtu by December 13, when California prices were between $4.00 and $4.15/MMBtu.

A price spike in NYMEX Henry Hub January 2003 futures contracts, ice storms through the Northeast and Midwest, and an EIA report showing 162 Bcf of withdrawals from storage during the week of December 9, all contributed to drive Henry Hub prices sharply higher on 12 December, with prices eventually peaking at $5.30/MMBtu on December 16, 2002. While weather was not as cold in California, heating demand was sufficiently high that PG&E Citygate prices reached $5.00/MMBtu and remained at that level until December 26. Moderating weather and reduced electricity demand due to the holidays caused prices to fall, with prices ending December between $4.00 and $4.60/MMBtu. Average bid week prices for November were $4.04, $4.04, and $4.12 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 1%, down 1%, and up 1% from November bid week prices. Average bid week prices for December were $4.57, $4.43, and $4.88 for SoCal Gas, Malin, and PG&E Citygate, respectively, up 13%, 9%, and 18% from November bid week prices. The following chart shows daily gas prices for November and December.

Figure 12. Natural Gas Hub Prices for November and December 2002



VIII. Regional Day-Ahead Bilateral Electricity Prices

Beginning in early November, California prices were consistently higher than prices at other external hubs by over $3/MWh during weekdays, and occasionally by as much as $7/MWh.

Nonetheless, prices declined from a high of $45 to $48/MWh in the beginning of November to below $30/MWh at Mid-Columbia, between $30 and $36/MWh at COB, and between $29 and $38/MWh at Palo Verde. On November 25th, with cold weather in the West and ongoing high natural gas prices, regional prices increased sharply, with Palo Verde and California prices above $40/MWh.

Cold weather and high natural gas prices resulted in higher electricity prices through the first three weeks of December. Weekday prices during the first two weeks averaged between $40 and $50/MWh, and between $45 and $54/MWh during the third week of December. Congestion on Path 15 due to line outages resulted in price spreads between Northern and Southern California for a few days in December. The multitude of holidays in December and the associated reduction in electricity load resulted in lower electricity prices for those days, but prices on non-holidays remained high until the end of December. The following chart shows day-ahead electricity prices at California area trading hubs for November and December.

Figure 13. Day-Ahead Bilateral Electricity Prices for November and December 2002