CALIFORNIA ISO

California Independent
System Operator

Memorandum

To: ISO Board of Governors

From: Anjali Sheffrin, Director of Market Analysis

CC: ISO Officers, ISO Board Assistants

Date: February 1, 2002

Re: Market Analysis Report for December 2001

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

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

EXECUTIVE SUMMARY

Costs for real-time energy and ancillary services stabilized in the fourth quarter of 2001, at levels lower than those seen since mid-2000. Real-time electricity prices increased moderately in December from November, as CERS ceased its out-of-market (OOM) procurement operations as of December 7, resulting in a movement of real-time procurement into the ISO's Balancing Energy Ex-Post Price (BEEP) auction market. However, market activity and prices remained light compared with levels seen earlier in 2001, due primarily to weak demand and greater reliance on forward contracts to serve load.

Overall, the average wholesale price of real-time incremental electricity increased to approximately $57 per megawatt-hour (MWh) in December, from approximately $48/MWh in November. The real-time price of decremental electricity decreased to approximately $8/MWh, from $9/MWh in November.[1] The cost impact of this decrease was minimal due to low real-time volume, which averaged less than 1 percent of total system load. Load averaged 25,310 MW, a level higher than that seen in November, due to winter heating needs, but lower than that seen in December 2000. The California Energy Commission (CEC) reports that total energy consumption has declined 4.4% compared to December 2000, after normalizing for growth and weather conditions. The Department of Market Analysis (DMA) continues to observe real-time prices above competitive benchmark levels.

The Federal Energy Regulatory Commission's (FERC) Orders of November 7 and 20, 2001, directing the ISO to enforce the creditworthiness provision of its Tariff and to treat the Department of Water Resources' California Energy Resources Scheduling Division (CERS) as it treats other scheduling coordinators (SCs), has resulted in CERS ceasing its OOM procurement operations as of December 7. DMA has observed that the bulk of the energy that CERS had been procuring in real time is now appearing in forward schedules and in the BEEP stack. Furthermore, CERS is now on schedule with payments for real-time energy delivered in 2001. FERC's series of Orders released December 19, 2001 directs the ISO to make significant changes in its market price mitigation methodology during the winter months.

[1] As of the September 2001 report, the DMA has been reporting 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.

Scheduling coordinators have continued to rely on self-provision of Ancillary Services (A/S) in recent months. A/S costs, as a percentage of total energy costs, have leveled off below 2 percent since October. Interzonal congestion costs were minimal.

KEY MARKET CONDITIONS FOR DECEMBER 2001

I. California Wholesale Energy Markets

Real-Time Market Highlights. FERC's price mitigation order of June 19, 2001, was in effect through December 19, imposing a soft price cap of $91.87/MWh on wholesale power markets in the Western United States. The ISO, in accordance with FERC's Orders of November 7 and 20, began treating CERS as a regular scheduling coordinator, and invoiced CERS for receivables past due for its real-time out-of-market (OOM) energy procurement operations. On November 29, CERS issued a letter of intent to satisfy its financial obligations to the ISO, and followed up on December 6 with its first payment for energy delivered in January 2001. The ISO disbursed these amounts to creditors on December 12. CERS has also ceased its OOM activities. CERS made OOM calls during the first seven days of December; however, since December 7, hour ending 4:00, no OOM calls have been issued by either CERS or the ISO. CERS is on schedule to satisfy the full amount of its past due obligations by February 28, 2002.

Market-clearing prices (MCPs) for incremental energy exceeded the $91/MWh level in 95 of the 2,934 ten-minute intervals in December during which the soft price cap was $91.87. On December 13, 2001, in hours ending 18:00 and 19:00, the MCP exceeded $91.85, and the ISO procured small quantities of energy as-bid (above the soft price cap) from the BEEP stack for the first time since September 2001.

On December 19, FERC concurrently released four Orders pertaining to the ISO real-time market, revising its price mitigation methodology that was established primarily in the Orders of April 26 and June 19, 2001. A consequence of these Orders was an increase in the soft price cap to $108/MWh. Please see the section on these FERC Orders for further discussion on the impact of the Orders.

Loads. Loads in December 2001 were lower than those in December 2000, due primarily to mild weather, continued conservation efforts by consumers, and a softening economy. Monthly system energy consumption for December totaled 18,830 gigawatt-hours (GWh), a 3% decrease from December 2000. The peak load for the month reached 33,159 megawatts (MW), a 1.5% decrease from the December 2000 peak of 33,672 MW. Daily peak loads averaged 30,718 MW, a 1.8% decrease from December 2000.

The California Energy Commission (CEC) provides estimates of conservation after normalizing for growth and weather conditions. The CEC calculated that monthly peak demand for electricity in December decreased by 2.3 percent from December 2000, a month in which conservation had already played a significant role in reducing load. Total monthly energy use, adjusted for growth and weather, dropped by 4.4 percent over the same period.

Wholesale Energy Prices. The ISO Department of Market Analysis (DMA) monitors several key price and volume statistics related to the real-time market. The real-time market now consists of several components as displayed in numbered columns in the following table: (1) the MCPs and quantities for incremental and decremental energy procured under the price cap from the BEEP Stack; 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. Average hourly system loads and percent underscheduling are shown in (4). The averages for each of these segments of total real-time purchases for peak, off-peak, and all hours are shown.

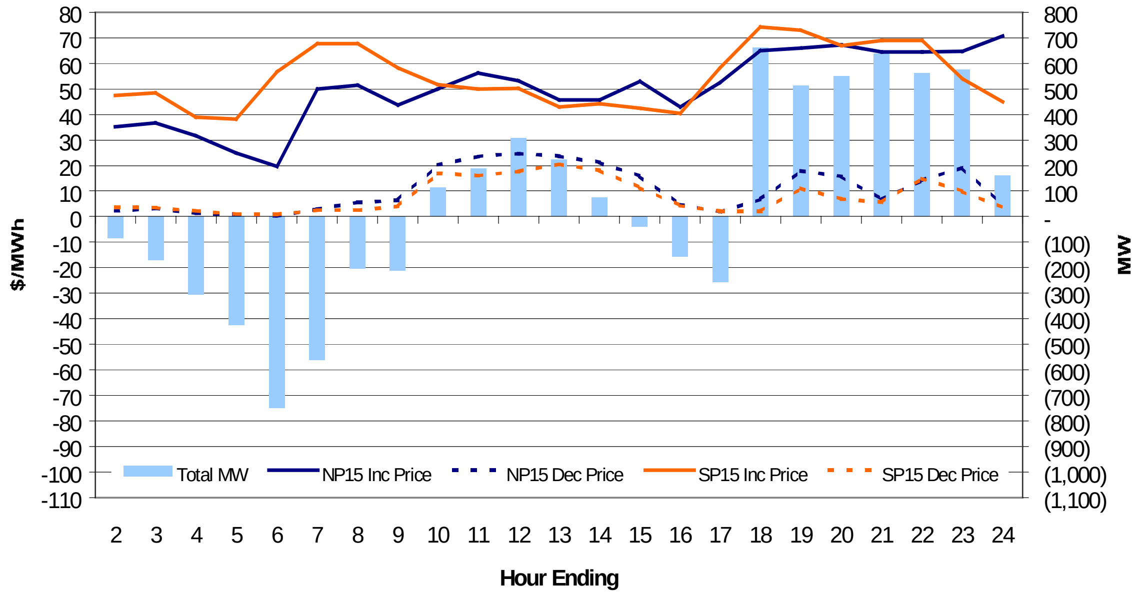
Table 1a: Real-Time Energy Price Summary for December 2001

	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	$ 61.05 186 GWh	$ 9.67 112 GWh	$ 40.02 17 GWh	$ 14.08 *	$ 59.27 203 GWh	$ 9.69 113 GWh	27,226 MW 1.0%
Off-Peak	$ 51.99 44 GWh	$ 3.85 76 GWh	$ 32.14 7 GWh	$ 21.90 3 GWh	$ 49.32 50 GWh	$ 4.61 79 GWh	21,476 MW -1.0%
All Hours	$ 59.32 229 GWh	$ 7.32 188 GWh	$ 37.78 24 GWh	$ 20.71 4 GWh	$ 57.28 253 GWh	$ 7.60 192 GWh	25,310 MW 1.0%

Average real-time INC energy prices increased approximately 19% between November and December, while DEC energy prices decreased approximately 18%. Average system load increased to 25,310 MW from 24,593 MW. On average, scheduling coordinators underscheduled by 1% in December, compared with 1% overscheduling in November.

The level of prices at which generators bid energy into the BEEP stack has been a problem during the evening peak hours ending 18:00 through 21:00. For at least 11 days in December, total MWh bid into the BEEP stack at prices under $50 were not sufficient to meet load at some point during these hours. Thus, the ISO found it necessary to procure energy at higher prices in order to meet load. Figure 1 shows real-time prices and quantities for incremental and decremental energy in December, averaged by hour of day (monthly averages are noted in column (3) of Table 1).

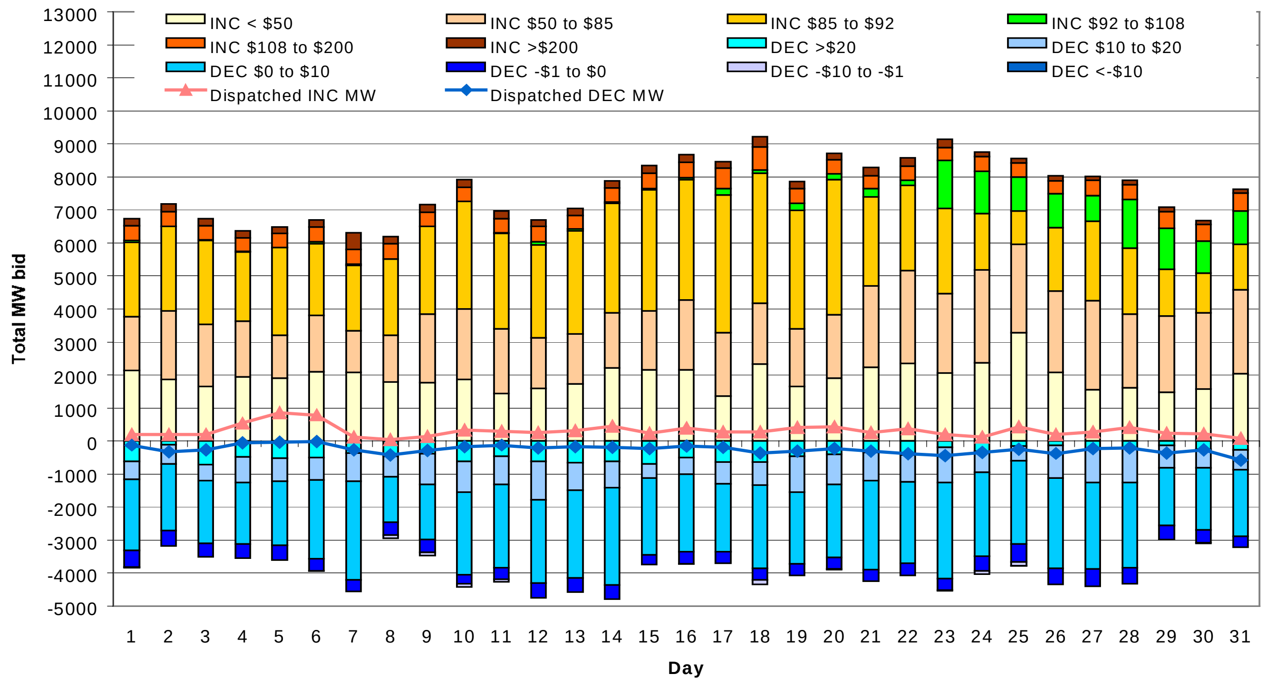
Figure 1: Hourly Average Real-Time INC and DEC Energy Prices and Quantities - December 2001



The volume of energy transactions traded in the ISO's BEEP market continues to be minimal. Beginning in January 2001, 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 through December 2001.

The soft demand situation has mitigated the ability of generators to exercise market power in the real-time markets. Most bids have been below the cap level, but generators continue to bid substantial portions of their energy near the price cap, and small portions above the cap. Indeed, the quantity of MWh bid in the range $92-$108 increased shortly after FERC increased the price cap from $91.87 to $108. Figure 2 shows bids into the BEEP stack by price bin for December, with INC and DEC volumes shown by MWh bid, depicted in shades of orange and blue, respectively. Volume for INC bids in the range $92-$108 is highlighted in green.

Figure 2: Original Bids into BEEP Stack (Hourly Average by Day) – December 2001



The lack of bids at low prices has been a problem during the evening peak hours ending 18:00 through 21:00. For at least 11 days in December, total MWh bid into the BEEP stack at prices under $50 were not sufficient to meet load.

The low prices for natural gas observed in recent months continue not to be wholly reflected in real-time spot prices, which have risen since November. This is partly explained by CERS' cessation of OOM activities. CERS procured OOM energy from generators in bilateral contracts for specific quantities of energy, whereas BEEP energy is an on-demand product, and may involve higher costs per unit of energy delivered. However, the volume of real-time energy procured in the ISO's control area in December was too low to calculate a meaningful estimate of the degree to which generators exercised market power. As noted, DMA has observed substantial BEEP procurements near the price cap, and will continue to report to FERC events that are indicative of the exercise of market power.

Key elements of FERC Orders of December 19, 2001. FERC directed that the ISO change the methodology used to calculate the BEEP auction market's soft price cap during the winter season (through April 30, 2002). The minimum level of the soft price cap is now $108/MWh, which was the production cost of the highest-cost unit dispatched during the most recent hour-long Stage 1 Emergency (on May 31, 2001), effective hour ending 10:00 on December 21, 2001. The cap previously had been set at $91.87, or 85 percent of this level. For the remainder of the 2002 winter season, the cap will be recalculated based upon bid-week gas prices, whenever the monthly average of the California gas price index increases or decreases by at least 10 percent, but no lower than $108/MWh.

FERC also changed the ISO's market rules concerning units that can set the MCP. For example, importers from outside the ISO's control area may now bid to set the MCP provided they submit heat rates, and hydro resources must now bid as price takers (i.e. submit bid prices of zero, and be paid the MCP). Previously, importers were required to bid as price takers, while hydro resources could bid to set the MCP.

In another Order, FERC issued directions concerning the ISO's process of granting exemption waivers to the requirement that generating units be available to produce energy in the real-time market. FERC validated the ISO's waiver-granting process, and specified that generating units are entitled to recover start-up and minimum-load costs, by invoicing the ISO for these costs separately from their real-time energy costs, whenever they are not granted waivers. However, units are not entitled to recover these costs when they are granted waivers but remain on line anyway.

FERC also directed that the ISO redefine a Stage 1 Emergency as a situation in which operating reserves fall below 7% of load, and that the ISO recalculate emergency-hour proxy MCPs (equal to the highest production cost of all dispatched units) back to May 29, 2001 based upon this rule. Previously, the ISO was able to exercise more discretion in declaring emergencies. The ISO will seek clarification from FERC in regard to whether these recalculated proxy MCPs will affect the aforementioned new minimum for the price cap.

FERC clarified that generators that submit bids above the price cap need only defend those bids as "just and reasonable" when they are actually dispatched. Moreover, such bids that are dispatched are now entitled to the 10% credit risk adder, which previously applied only to energy procured at the MCP. While DMA has observed an increase in MWh bid in the $92 - $108 range since December 19 (as shown by the green stack in Figure 2), it has not detected any substantial increase in MWh bid above the price cap. DMA will continue to monitor bidding behavior and report to FERC incidents that are indicative of the exercise of market power.

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

Ancillary Service Prices

Ancillary services (A/S) are procured through day-ahead and hour-ahead markets to meet reserve requirements. 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, pursuant to FERC's Order of December 15, 2000. This has resulted in significant savings.

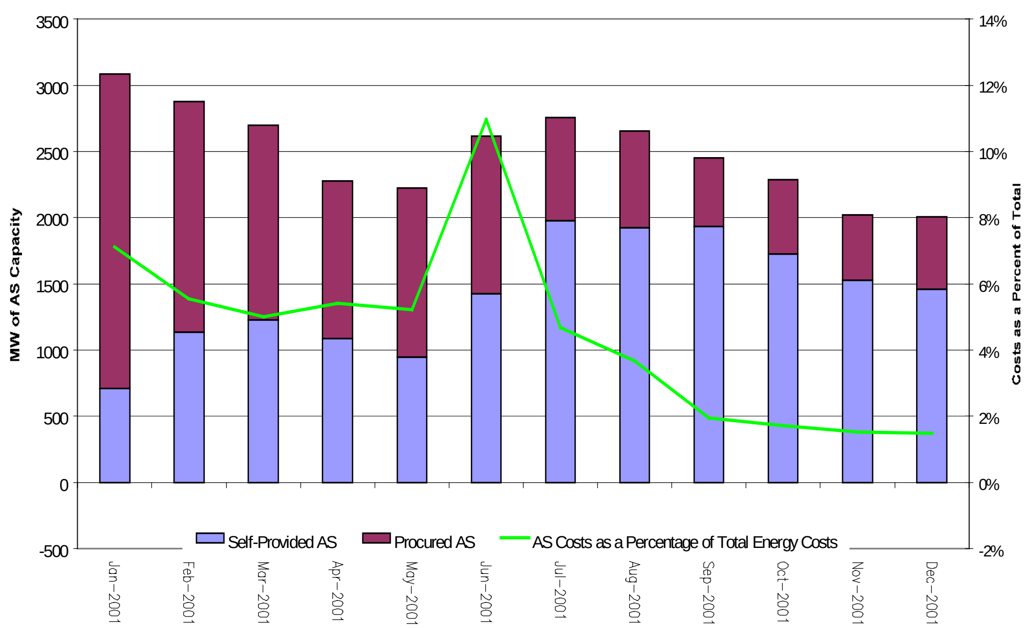
Changes in average prices for A/S were mixed between November and December. Upward and Downward Regulation prices respectively increased and decreased by approximately 17% and 8% to $14 and $11. Average prices for Spinning, Non-Spinning, and Replacement Reserves have all remained under $3 since October 2001. Between 79% and 96% 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 December, in both the day-ahead and hour-ahead markets.

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

	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	$ 14	$ 19	$ 14	477	50	90%
Regulation Down	$ 11	$ 12	$ 11	455	61	88%
Spin	$ 2	$ 3	$ 2	745	24	96%
Non-Spin	*	$ 2	*	744	30	96%
Replacement	$ 2	$ 6	$ 3	89	23	79%

Since January 2001, SCs have increasingly self-provided A/S. In December, approximately 27% of the total MW of capacity required were self-provided. Figure 3 shows the volume of A/S self-provided by SCs, compared with the volume procured through the ISO's A/S markets. The graph also shows explicit A/S procurement costs as a percentage of total energy costs (in green), which had declined since June 2001, and has fallen below 2% for the last three months of 2001.[3]

Figure 3: Self-Provided and Procured Ancillary Services



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[2] 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. An asterisk (*) indicates a price below $1. 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.

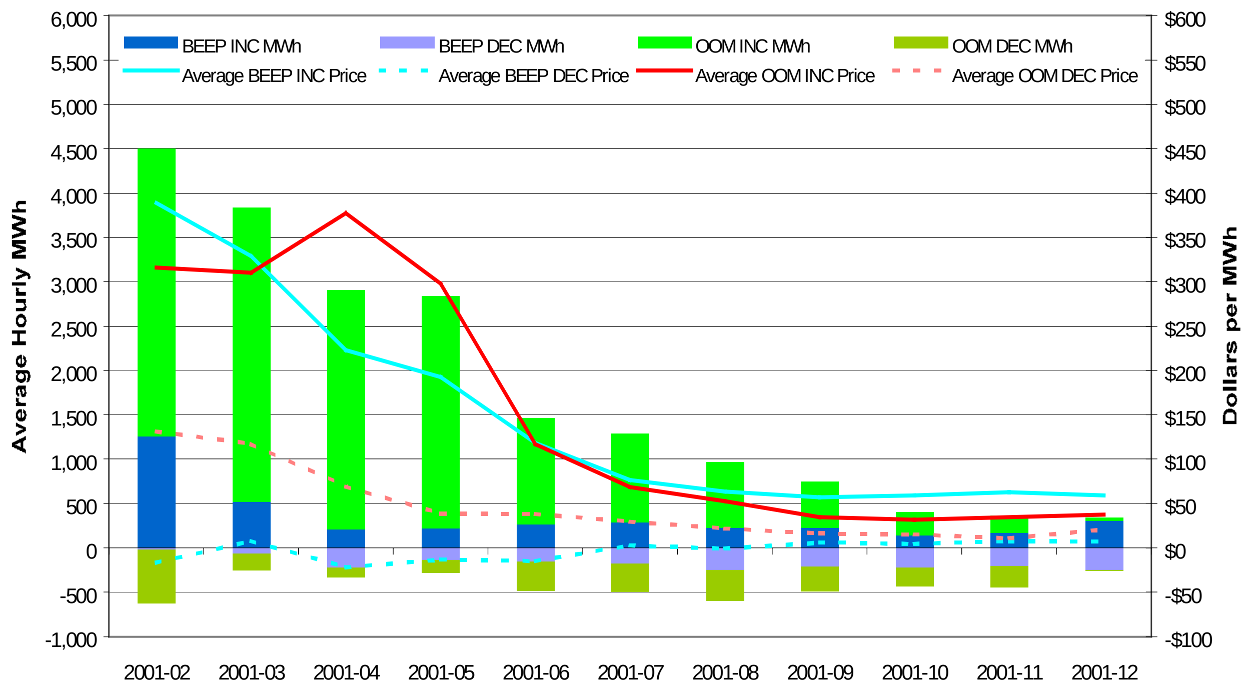
[3] We note that this understates the true economic costs of A/S. When a SC self-provides A/S, the cost of A/S is included in the SC's bid price for energy. This cost is thus not included in computation of the data underlying the green line. However, this cost is presumably small during periods of overscheduling, since most generators have plenty of reserve capacity at that time.

III. Out of Market (OOM) Calls and BEEP Volumes

As noted earlier, CERS ceased OOM procurement activities as of December 7. For the remainder of the month, the ISO did not procure any OOM energy. Through December 7, DMA estimates that average OOM INC and DEC prices were $43.86/MWh and $20.71/MWh, compared with November OOM INC and DEC prices of $36.31 and $10.72, respectively. On an hourly average basis, December INC and DEC OOM quantities were 60 MW and 4 MW, respectively. DMA estimates the total cost of OOM purchases in December decreased to approximately $0.8 million from $3.3 million in November.[4]

Hourly OOM INC and DEC volume and prices are compared with corresponding BEEP statistics below in Fig 4.

Figure 4. Average Hourly of BEEP and Out-of-market Purchases



Since December 7, additional energy has been appearing in the BEEP stack and in forward markets. In accordance with FERC's Order of November 20, 2001, DMA will not detail CERS' activities in particular after December 7.

IV. Summary of Market Costs

The total costs of energy and A/S amounted to approximately $838 million in December, up from $796 million in November. This is the seventh 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 $45/MWh in November to $44/MWh in December. 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 nine 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 $7.43 billion (for twelve months), with an average of $33/MWh as well. However, costs increased substantially in 2000.

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[4] Total OOM costs are net INC and DEC costs. October cost statistic is updated from the previous report. In accordance with FERC Order of 11/7/2001, DMA will report separate INC and DEC OOM volumes as of this report. Since CERS OOM calls are bilateral contracts between the State of California and suppliers, exact prices are not available to the ISO.

For the entirety of 2001, total energy and A/S costs have exceeded $26.7 billion, with an average cost of $118/MWh of load served. Total costs for energy and A/S in 2000 were approximately $27.08 billion, resulting in an average cost of $114/MWh of load served. The increase in cost per MWh is due primarily to the extraordinary costs incurred between November 2000 and May 2001. This trend reversed in June, and prices for the summer and fall have been substantially lower than those in 2000. Table 4, on the following page, provides a summary of energy and A/S costs. The costs estimated in this table include estimates for utility generation, CERS purchases prior to December 7, and bilateral transactions to serve load within the ISO control area.

Table 4: Summary of Estimated Market Costs, January through December 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
OCT-01	19,105	19,395	$ 854	$ 10	$ 15	$ 864	$ 878	$ 45	$ 0.77	1.7%	$ 46
NOV-01	17,707	18,028	$ 774	$ 10	$ 12	$ 784	$ 796	$ 44	$ 0.68	1.5%	$ 45
DEC-01	18,830	18,673	$ 811	$ 14	$ 12	$ 826	$ 838	$ 44	$ 0.65	1.5%	$ 44
Total 2001	227,024	220,484	21,194	4,162	1,346	25,356	26,702				
Avg 2001	18,919	18,374	1,766	347	112	2,113	2,225	114	6	5.3%	$ 118

***** Sum of hour-ahead scheduled quantities
** Includes UDC costs (estimated at costs of production), CDWR costs (after 8/2001, projections only), and other bilaterals estimated 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

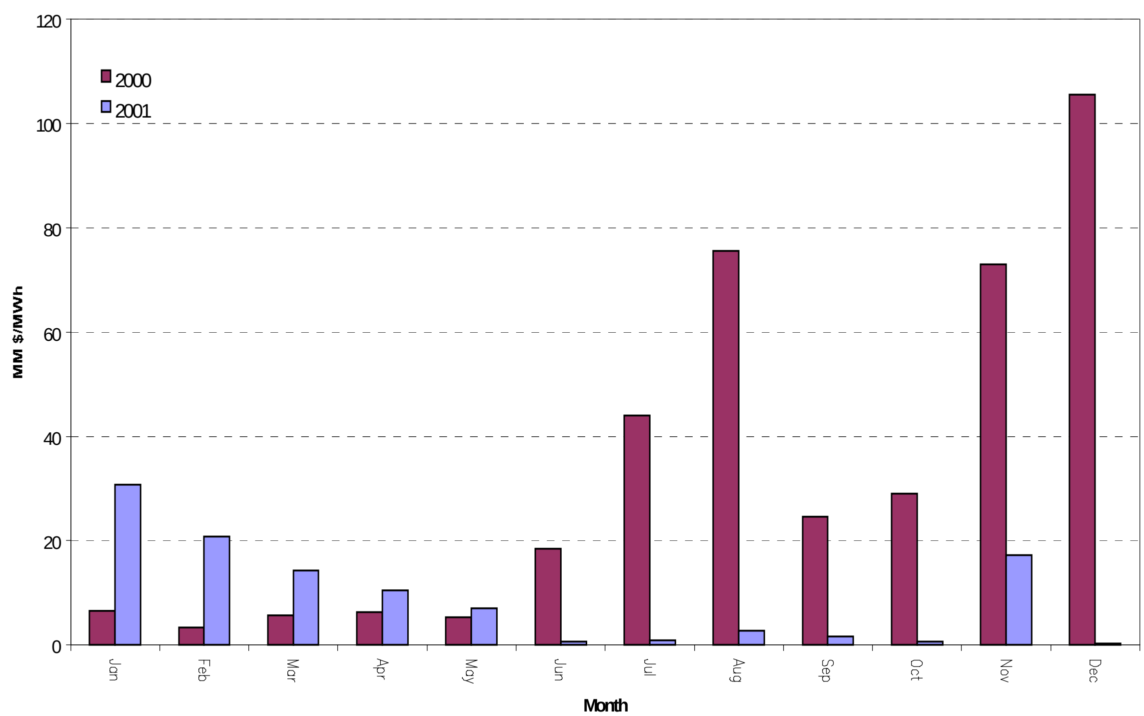
Congestion in December was limited primarily to day-ahead imports on COI and Eldorado; day-ahead South-to-North activity on Paths 15 and 26; hour-ahead imports on COI, Eldorado, Mead, NOB, Palo Verde, and Sylmar; and hour-ahead South-to-North activity on Path 15. Total congestion costs for December were approximately $300,000 in December, compared with over $17 million in November. Import congestion on Palo Verde accounted for over $16.4 million of the total congestion costs in November, due in large part to the simultaneous derates of Palo Verde and NOB, on November 13.

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

Table 5: Day-Ahead Congestion Summary for December

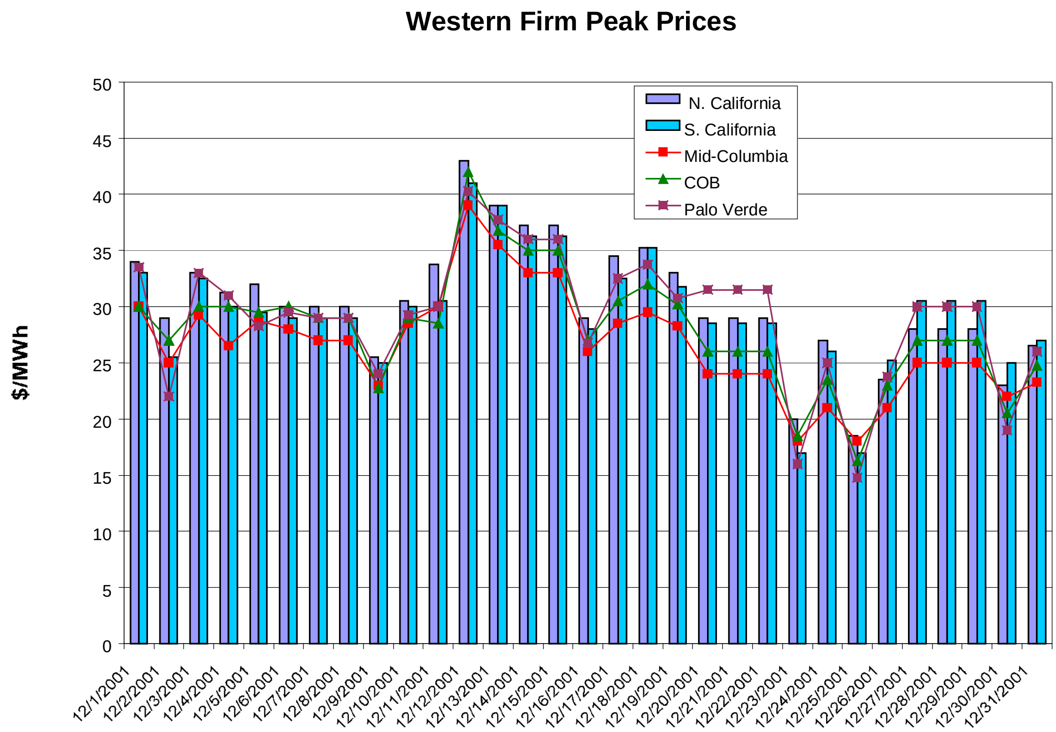
	Percentage Congestion by Period			Average Congestion Charges ($/MW)		
	Peak	Off peak	All Hours	Peak	Off peak	All Hours
COI (Import)	6.46%	2.27%	4.97%	$0.05	$0.20	$0.08
Eldorado (Import)	0.42%	0%	0.27%	$30		$30
Path 15 (S-N)	46.67%	98.86%	65.19%	$0		$0
Path 26 (S-N)	0.42%	1.52%	0.81%	$52	$57	$55.33

Figure 5: Comparison of Monthly Inter-zonal Congestion Costs



VI. Western Regional Market Prices

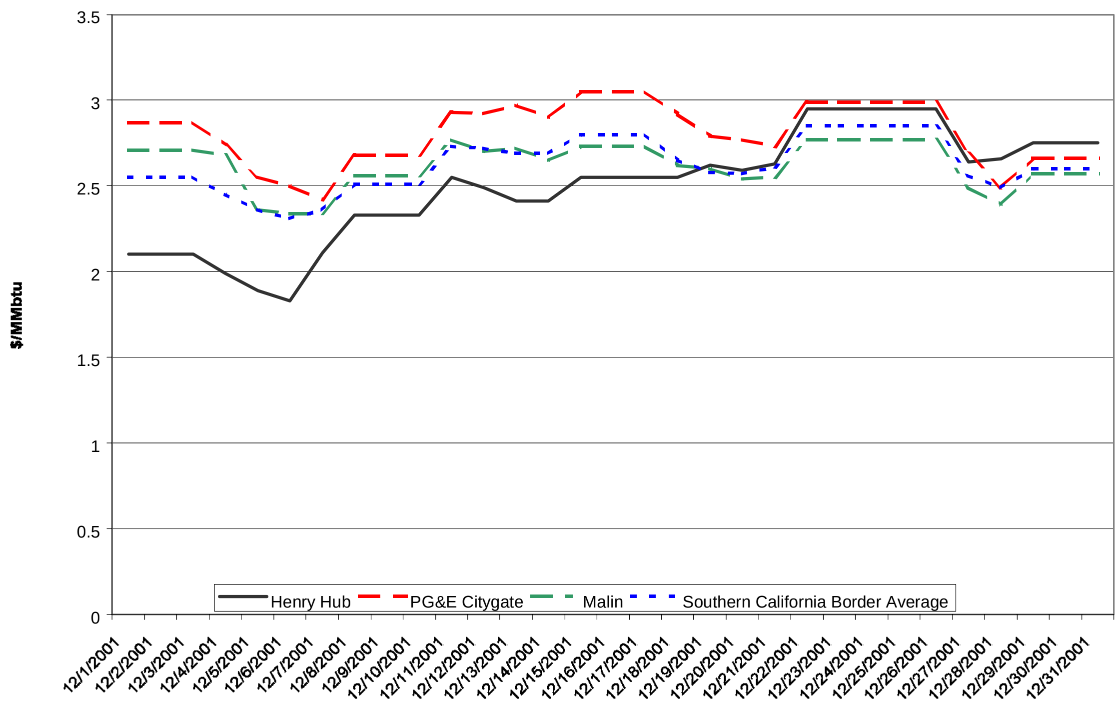
Figure 6: Western Regional Spot Electric Market Prices[5]



Volatility of Western peak power prices decreased significantly in December. Prices remained predominantly within the $20/MWh to $35/MWh price range, with some exceptions. Weak natural gas spot and futures prices helped to keep peak power prices low through the month as well. The first two weeks of the month saw prices staying generally within the $25 to $35/MWh range, with occasional dips below $25/MWh, due to slightly warmer weather. Prices then spiked to around $40/MWh on December 13, owing to increased heating demand and higher spot gas prices caused by cooler temperatures, and several forced unit outages; in particular, Four Corners #4 was out due to repairs on a condenser leak, and Mohave #2 was out due to control valve problems. Prices remained high, but decreased somewhat, as these units were out and temperatures remained cool, falling to the $30/MWh level by December 16. The holiday season resulted in reduced demand between the 24th to 26th, where prices plunged, and rose again following the 26th. By the end of the month, peak power prices were approximately $25/MWh.

[5] Prices are peak hour, firm product prices as reported by Energy Market Report, published by Economic Insight, Inc.

Figure 7: California Natural Gas Prices



As with Western power prices, natural gas price volatility was significantly reduced compared to November, with prices trading within the $2.25 to $3.00/MMbtu range by the end of December. Warm temperatures across much of the continental U.S. drove down demand slightly during the beginning of the month. With plentiful supply of natural gas, prices dipped slightly during the first week of December. The second week saw somewhat cooler temperatures and rising prices, but the high natural gas supply levels kept prices at low levels. Temperatures were cold enough to maintain steady demand during the latter half of December; coupled with still high levels of supply, prices remained flat through much of the rest of the month, although warming temperatures in Southern California caused prices to dip slightly at the end of December. Average bid week prices for January were $2.62, $2.61, and $2.85 for SoCal Gas, Malin, and PG&E Citygate, respectively.

VII. Performance of the Firm Transmission Rights Market

FTR Concentration

One Firm Transmission Rights (FTR) contract changed hands in the secondary market on December 11, 2001 -- a transfer of 101 MW for Palo Verde in the import direction from Aquila Power (AQPC) to Trans-Alta (TRAL), for peak hours on selected days in December, and for all hours for the remainder of the current FTR period from January through March 2002. Because most paths with relatively high FTR concentrations recorded low frequencies of congestion (all below 10 percent, except for Path 15, for which no FTRs are auctioned), FTR concentration levels do not raise concerns at this time. The Following table shows FTR ownership concentration at or above 25% on different paths (Branch Group and direction) as of the end of December 2001.

Table 6: FTR Concentration Ratios for December

Branch Group	Owner ID	Owner Name	Max FTRs Owned	Hours Max FTR Owned	Total FTRs Auctioned	% Conc.
		export direction				
SILVERPK	IPC1	Idaho Power Company	10	2184	10	100
NOB	VERN	City of Vernon	82	2184	111	74
ELDORADO	IPC1	Idaho Power Company	401	2184	626	64
COI	SCEM	Mirant	33	2184	56	59
VICTVL	IPC1	Idaho Power Company	166	2184	296	56
CFE	PETP	PG&E Energy Trading Power, L.P.	200	2184	408	49
PALOVRDE	WESC	Williams Energy Services Corporation	381	2184	796	48
MEAD	IPC1	Idaho Power Company	213	2184	456	47
COI	IPC1	Idaho Power Company	23	2184	56	41
PATH26	SCE1	Southern California Edison Company	575	2184	1727	33
PATH26	PETP	PG&E Energy Trading Power, L.P.	500	2184	1727	29
PATH26	SCEM	Mirant	477	2184	1727	28
MEAD	SCEM	Mirant	125	2184	456	27
CFE	IPC1	Idaho Power Company	106	2184	408	26
VICTVL	VERN	City of Vernon	75	2184	296	25
PALOVRDE	IPC1	Idaho Power Company	200	2184	796	25
CFE	MSCG	Morgan Stanley Capital Group, Inc.	102	2184	408	25
		import direction				
SILVERPK	SCE1	Southern California Edison Company	10	2184	10	100
ELDORADO	SCE1	Southern California Edison Company	582	2184	707	82
IID-SCE	SCE1	Southern California Edison Company	460	2184	600	77
PATH26	SCEM	Mirant	100	2184	199	50
NOB	SCE1	Southern California Edison Company	250	2184	523	48
CFE	MSCG	Morgan Stanley Capital Group, Inc.	171	2184	408	42
PATH26	NEI1	NewEnergy Inc.	74	2184	199	37
COI	IPC1	Idaho Power Company	219	2184	600	37
PALOVRDE	SCE1	Southern California Edison Company	602	2184	1819	33
VICTVL	MSCG	Morgan Stanley Capital Group, Inc.	316	2184	1013	31
VICTVL	SCEM	Mirant	314	2184	1013	31
PALOVRDE	WESC	Williams Energy Services Corporation	500	2184	1819	27
MEAD	SCEM	Mirant	125	2184	487	26

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 for December amounted to 18% of the total available FTR volume on all paths, compared to 17% in November. On some paths, relative volume was was high (e.g., 83% on Eldorado, 100% on Silverpeak, and 71% on IID-SCE, all in the import direction). However, these paths exhibited low congestion frequency. FTR scheduling was not significant on paths with high FTR ownership concentration, such as NOB (export direction) and Victorville (export direction). The following table shows the paths on which 1% or more of FTRs were attached to schedules, along with related statistics, for December.

Table 7: FTR Scheduling Statistics for December

	Import							Export
IMPORT	COI	ELDORADO	IID-SCE	MEAD	PALOVRDE	SILVERPK	VICTVL	PATH26
MW FTR Auctioned	600	707	600	487	1,819	10	1,013	1727
Avg. MW FTR Sch.	141	589	427	17	764	10	12	37
% FTR Schedule	24%	83%	71%	3%	42%	100%	1%	2%
Max MW FTR Sch.	326	707	450	100	1,112	10	37	269
Max Single SC FTR Schedule	200	582	450	50	600	10	25	269

VIII. Issues Under Review and Analysis

FERC December 19 Orders

As noted previously, FERC issued several Orders on December 19 that contain changes and clarifications to the market power mitigation provisions of the April 26 and June 19 Orders. These include clarification on compensation of minimum load costs for generating units complying with the must-offer provision, clarification on which units are eligible to set the market-clearing price in the ISO's real-time market, and changes to the West-Wide Price Limit during the winter period ending April 30, 2002. DMA is actively involved in reviewing these orders and assisting the ISO in developing compliance and rehearing filings.

Refunds

DMA continues to play a lead role in refund proceedings before FERC. FERC's Order of December 19, 2001, makes a relatively minor modification in the methodology initially outlined in its July 25, 2000 Order for calculating the prices to be used in mitigated sales in the ISO and PX markets, for the period from October 2, 2000 to June 20, 2001. Rather than identifying the marginal unit to be used in setting the mitigated price each interval based on heat rates, as specified in the July 25 Order, the December 19 Order requires that the marginal unit be identified based directly on estimated marginal fuel costs (i.e. the unit's heat rate, multiplied by published prices for the daily spot market gas purchases). The modification necessitated that the ISO recalculate prices previously submitted in the refund proceedings. On January 10, 2002, the ISO submitted supplemental testimony, including revised calculations of the prices to be used in mitigating transactions during the refund period.

DMA also performed analysis to estimate the impact of this methodological modification made in the December 19 Order on overall refunds. Results indicate that refunds would be about 3-4% lower with these revised prices, relative to estimates based upon the methodology initially specified in the July 25 Order. Results of this analysis were used to support a request by the ISO made in administrative proceedings in January that the magnitude of this impact would not warrant proceeding with another re-run of the ISO settlement system at this time. The ISO's request was granted by the Administrative Law Judge presiding over the case, avoiding the need to incur the time and expense of another settlements re-run at this time.

Following the December 19 Order, energy suppliers filed requests for clarification or rehearing on a number of key methodological issues affecting refunds. Most notably, they have asked the Commission to rule (1) that the mitigated price calculated pursuant to the July 25/December 19 Orders should be applied as a new transaction price, rather than as a limit on historical prices in the ISO and PX markets; and (2) that the ISO should calculate the mitigated price using average heat rates (including extremely high heat rates of units operating at minimum load levels) rather than the incremental heat rates used by the ISO to calculate unit marginal costs. All issues raised by the suppliers have already been addressed by the ISO in initial testimony submitted in the administrative proceedings, and will be addressed in an answer filed with the Commission in response to the generators' requests for rehearing and clarification.

The revised schedule for refund proceedings calls for another round of testimony in February, followed by a hearing on the mitigated price to be used in calculating refunds, on March 11-15. Hearings on the total amount of refunds, and the determination of which parties are to pay and which are to receive payments, are scheduled for June 17-20, so that any findings of fact and recommendations from the Administrative proceedings may be sent to the Commission in July 2002.