Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: June 21, 2002

Re: Market Analysis Report for May 2002

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

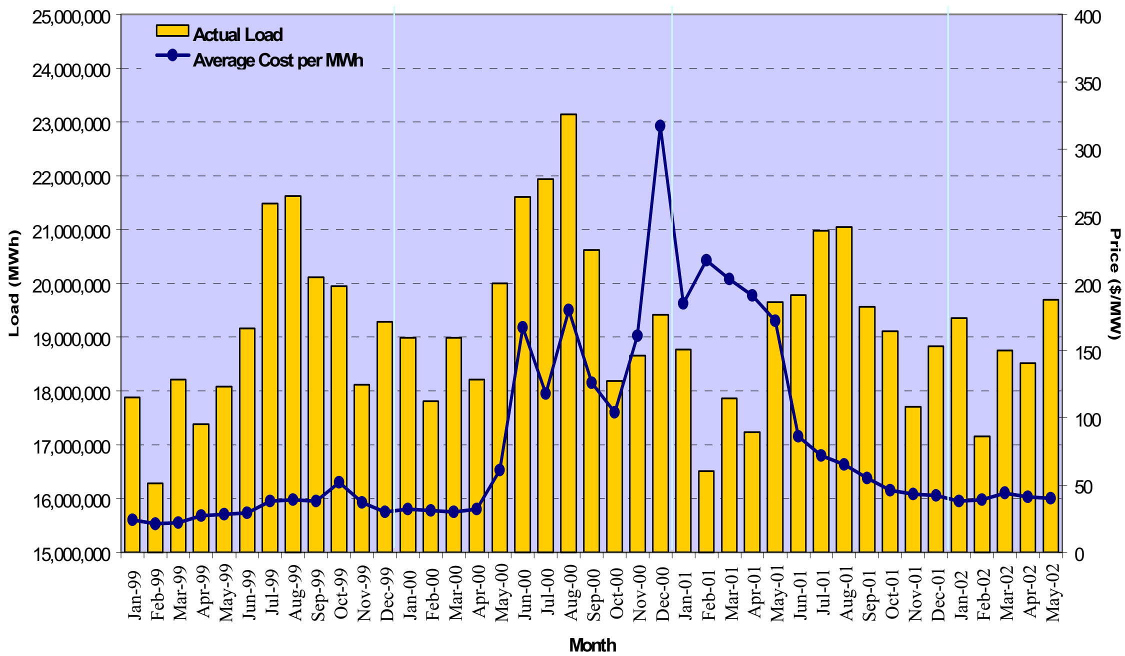
Executive Summary

Total energy costs stayed relatively constant between April and May despite higher demand than last year, as ISO load continued to benefit from plentiful hydroelectric supplies in the Pacific Northwest and from low gas prices in California. The average cost to load of energy and ancillary services remained at $41 per megawatt-hour (MWh) in May, unchanged from the April level, and within the range of $39 to $46/MWh for the eighth consecutive month, as shown below in Figure 1. Average prices for real-time energy needed to balance load in May were similar to those seen in April. Specifically, average prices for incremental (INC) and decremental (DEC) energy in May respectively were $54.13/MWh and $3.96/MWh. A notable change in real-time market performance between April and May was the rise in underscheduled load during peak hours, prompting a 26 percent increase in real-time INC volume.

However, the volume of bids for decremental (DEC) energy in the ISO's real-time Balancing Energy Ex-Post auction market (the BEEP Stack) has not been sufficient to balance generation with load in off-peak hours, and during periods of overscheduling in particular. In what has become a daily problem in cost as well as reliability terms, scheduling coordinators (SCs) have consistently scheduled more energy over ISO transmission lines than load has consumed. In order to maintain system frequency, ISO operators at times have had to dispatch every available DEC bid in the BEEP Stack, often at prices that would be very attractive to suppliers, and still have found it necessary to make out-of-market (OOM) calls to balance generation with load. Inactivity by some suppliers results in ISO operators' reliance on certain other suppliers for DEC energy when needed. This has the compound effect of compromising system-wide reliability, and conferring market power on the more reliable suppliers.

The following chart shows monthly system load and average total cost to load through May.

Figure 1. System Load and Average Cost by Month



I. Energy Market Statistics

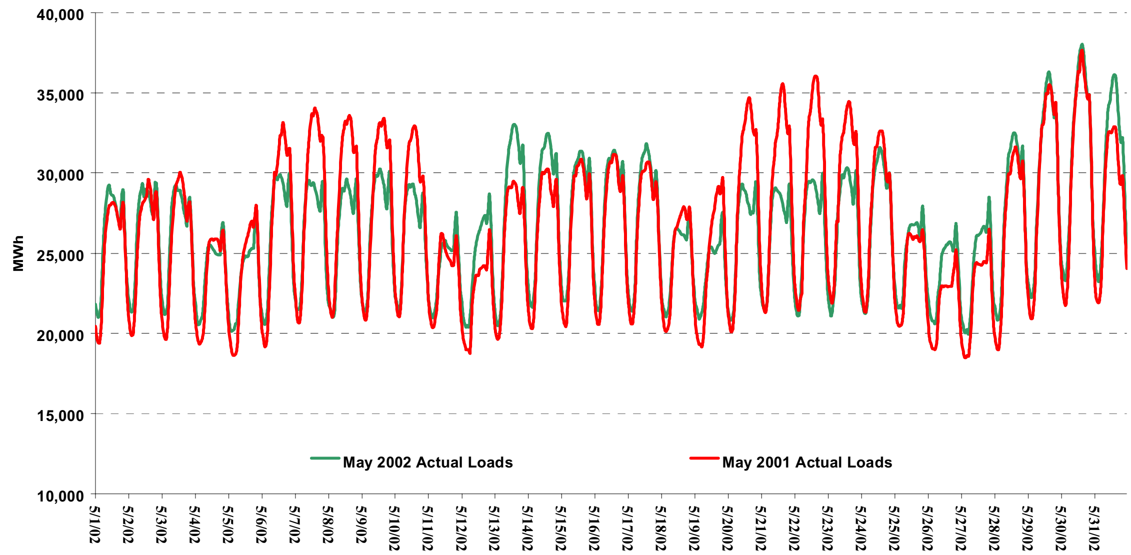
Loads. ISO Load totaled 19,690 gigawatt-hours in May, or an average of 26,465 megawatts (MW) for the month. In comparison, hourly load was 26,412 MW in May 2001, and 25,710 MW in April 2002.

The table below compares monthly average peak and average loads by hour in May 2001 with those in May 2002. The chart that follows compares actual hourly loads in May 2001 with those in May 2002.

Table 1. Monthly Peak and Average Loads: May 2001 and 2002

	2001	2002	Pct. Chg.
Peak Load (MW)	37,633	38,016	1.0%
Avg. Energy (MW)	26,412	26,465	0.2%

Figure 2. Hourly Loads: May 2001 and 2002

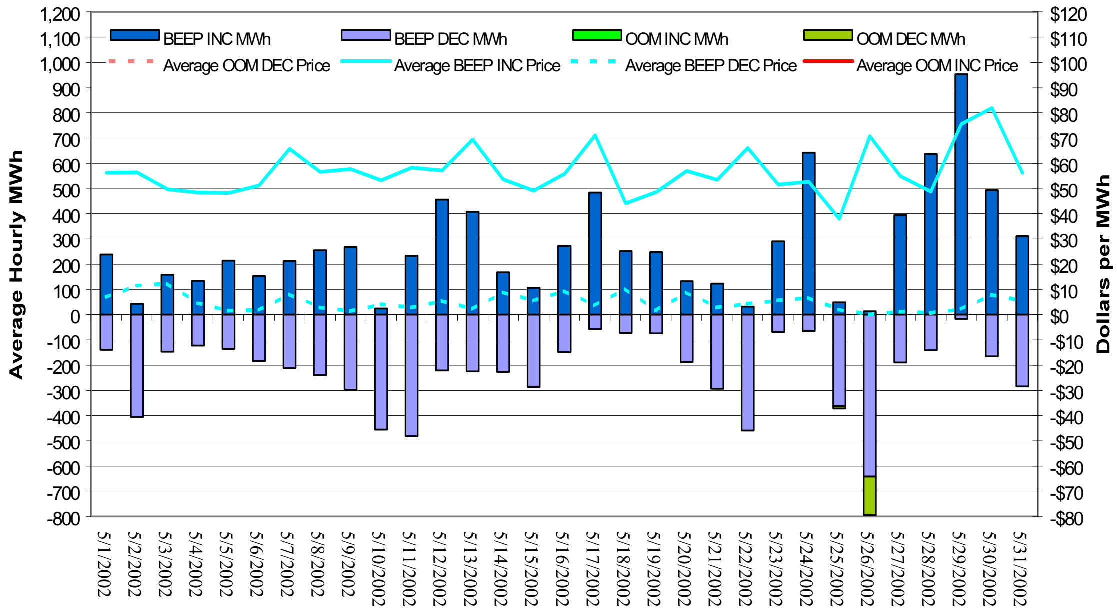


Conservation. The California Energy Commission (CEC) estimates conservation levels as changes in total energy and peak load, adjusted for growth and weather conditions. The CEC reports that adjusted monthly peak load increased 3.9 percent above the May 2001 level, but was 6.9 percent below the May 2000 level.

Real-Time BEEP Prices and Volumes. The average monthly real-time INC price has inched upward to $54.13/MWh in May, compared to $53.16/MWh in April. INC volume was 194 GWh in May, or an average of 260 MW in hours with INC volume, compared to 207 MW in April. The average monthly real-time DEC price was $3.96/MWh in May, compared to $3.75/MWh in April.[1] DEC volume was 165 GWh in May, or an average of 222 MW in hours with DEC volume, compared to 220 MW in April. The overall increase in INC volume is the result of an increase in underscheduled load from 2 percent to 3 percent of total load. The following chart shows real-time BEEP volumes and average prices by procurement type.

[1] OOM and overall average real-time prices were incorrectly reported in the April report. Please see the addendum to the April report for corrections.

Figure 3. Daily Average Real –Time Market Volumes and Prices for May 2002



The Federal Energy Regulatory Commission's (FERC) Orders of April 26 and June 19, 2001, permit the ISO to procure balancing incremental energy bid into the BEEP Stack at prices above the soft price cap of $91.87/MWh when procurement below the cap is not sufficient to meet load. In such a case, these offers to provide energy at prices above the cap would be paid "as bid"; that is, the bids are paid at the offered price, but may not set the market-clearing price (MCP). The MCP would instead be set by the highest-priced bid below the price cap that is accepted. Submitters of these bids must then show justification to FERC that their above-cap prices are cost-justified, or face refund. As of this report, no suppliers have yet succeeded in justifying as-bid prices.

In May, the ISO procured as-bid energy in five of 744 hours. All were for incremental energy during afternoon peak hours. In two hours on the afternoon of May 29, the ISO made two small as-bid procurements at $250/MWh, the highest real-time price seen since September 1, 2001, at a total cost of $18,693. May 29 came in the midst of a sudden heat wave and had the highest loads of the year to date. Southbound congestion on Path 15 and derates of several other key transmission lines made this procurement necessary.

Real-Time Out-of-Market Procurement. In hours of operation during which SCs have scheduled more electricity in the forward markets than actually is consumed by load, ISO control operators must instruct generators to decrement their electricity output in real time. To express their interest, generators bid prices they are willing to pay to be decremented as DEC bids in the BEEP Stack. The lowest accepted DEC price sets the market-clearing price (MCP) that every generator dispatched to DEC must pay. Lately, the volume of DEC bids submitted has not been sufficient to balance generation with load in all hours, particularly during the nighttime off-peak and morning shoulder hours. Consequently, the ISO has had to rely on out-of-market (OOM) transactions, which are negotiated as bilateral transactions between the ISO and the SC.

Procuring energy through OOM transactions can be costly in the long run. Because transactions are bilateral and must be kept confidential, they inhibit price discovery. This reduces competition, as potential suppliers are less likely to know when they will be profitable, so they have an incentive to demand higher prices than they would in a single-price market such as the BEEP Stack.

The ISO made OOM calls in twelve of 744 hours in May.[2] All were DEC calls, during the overnight off-peak and morning ramp hours. The average OOM DEC price was $ -0.13/MWh. That is, the ISO was required to pay generators an average of $0.13/MWh to decrease load, when the volume of DEC bids in the BEEP Stack was not sufficient to reduce generation in periods of overscheduling. Total BEEP volume for the month was 4 GWh.

Overscheduling. Over the past several weeks, the ISO has had to manage large amounts of overscheduled generation in off-peak hours on off-peak days. This problem is exacerbated by the lack of sufficient decremental energy bids in off-peak hours. The ISO continues to work with the IOUs and CERS to ensure greater scheduling accuracy.

The ISO monitors key price and volume statistics for real-time energy that it procures on behalf of load. The following table shows (1) average prices and total volumes for real-time energy procured through the BEEP Stack at the MCP, below the price cap; and (2) procured through the BEEP Stack as bid, above the price cap. The combination of (1) and (2) comprise the average price and total volume of (3) overall BEEP procurement. Also shown is (4) average OOM prices and volumes. The combination of (3) and (4) comprise (5) average real-time prices and total volumes of all real-time balancing energy. The final column (6) shows average system loads and percent underscheduling.

Table 2. Real-Time Energy Statistics for May 2002

	Avg. Market-Clearing Price and Total Volume (1)		Avg. Out-of-Market Price and Total Volume (2)		Overall Avg. Real-Time Price and Total Volume (3)		Avg. System Loads (MW) and Pct. Underscheduling (4)
	Inc	**Dec**	**Inc**	**Dec**	**Inc**	**Dec**	
Peak	$ 54.35 164 GWh	$ 5.56 88 GWh	No Procurement *	$ 1.21 *	$ 54.46 164 GWh	$ 5.52 89 GWh	28,463 MW 3%
Off-Peak	$ 52.39 31 GWh	$ 2.26 73 GWh	No Procurement *	$(0.54) 3 GWh	$ 52.39 31 GWh	$ 2.15 76 GWh	22,468 MW 1%
All Hours	$ 54.05 194 GWh	$ 4.06 161 GWh	No Procurement *	$(0.13) 4 GWh	$ 54.13 194 GWh	$ 3.96 165 GWh	26,465 MW 3%

* Indicates less than 1 GWh of procurement for the month.

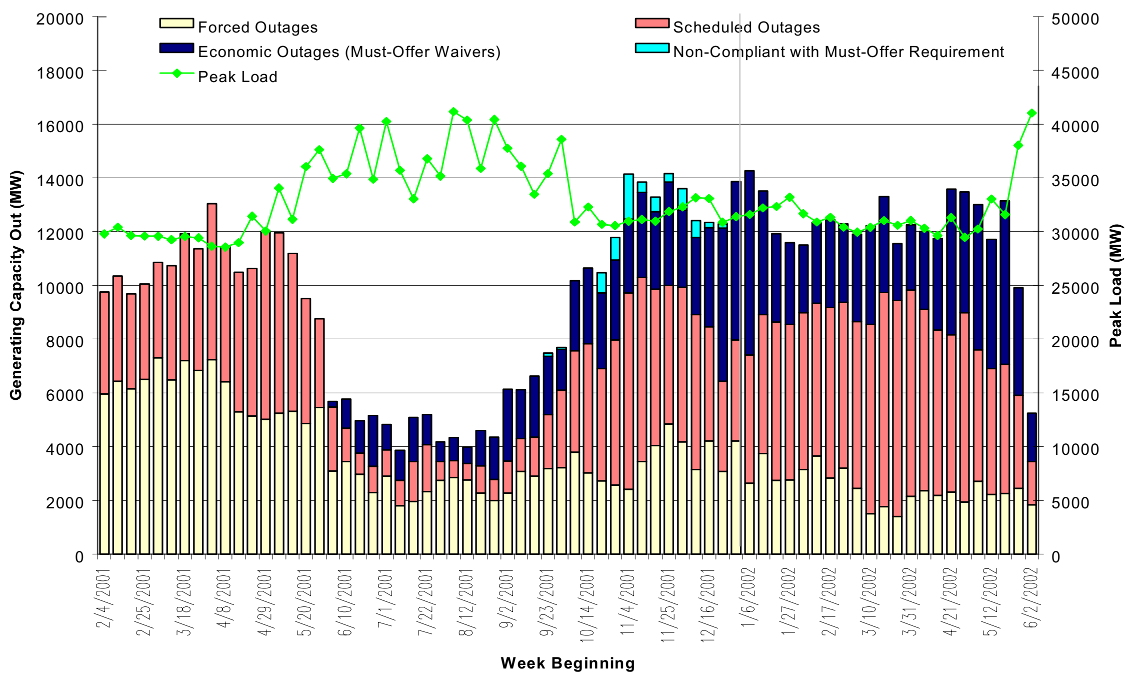
[2] ISO operators make OOM calls as a last resort, when they are unable to balance scheduled generation with actual load by dispatching resources that have submitted bids into the BEEP Stack.

Price Cap Hits. The ISO monitors the frequency with which the BEEP MCP comes within $1 of the current soft price cap. Pursuant to the FERC Orders of June 19 and December 19, 2001, the cap reverted to its summer-season level of $91.87/MWh on May 1, and, subject to further directions by FERC, will remain at this level until the next hour of reserve deficiency due to excessive load.[3] The mitigation is set to expire September 30, 2002.

The MCP came within $1 of the price cap or exceeded it in 24 of 2058 intervals (1 percent) in which the ISO procured incremental energy in NP15, and in 30 of 2051 intervals (1 percent) in SP15. Most were in peak afternoon hours on May 29 and 30, days on which peak load reached 36,307 MW and 38,016 MW, respectively. This was the largest frequency of hits since December 2001. There were no hits in either zone in March 2002.

Outages. The volume of generating capacity subject to outage has decreased in the last weeks of May and the first week of June. Approximately 3,200 MW of capacity planned to be out returned to service between May 19 and June 8. In addition, peak loads in excess of 40,000 MW over the same period, due to unseasonably hot weather in California, prompted ISO operators to call back to service approximately 4,300 MW of capacity that had been waived from the Must-Offer Requirement. The following chart shows weekly average outages by type through the first week of June.

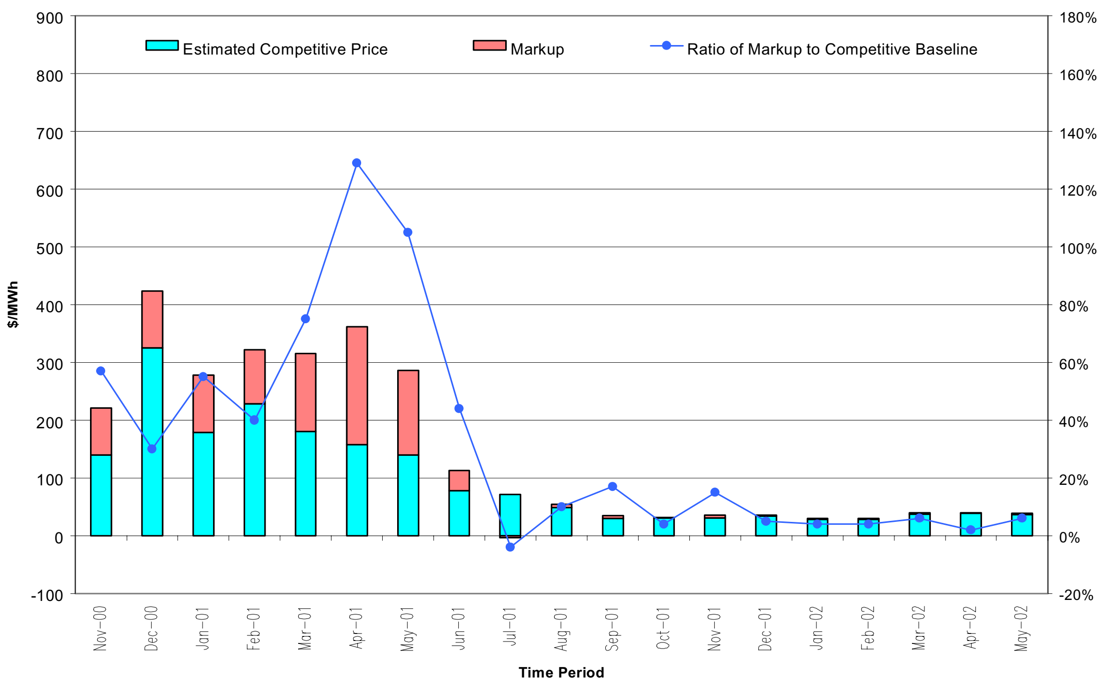
Figure 2. Weekly Average Outages by Outage Type



[3] The ISO sustained a full hour of reserves below 7 percent when the Path 26 transmission line was derated to zero MW due to a brush fire on June 5. The ISO is currently seeking clarification from FERC in regard to resetting the price cap during deficiencies that are not related to load or availability of generation.

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 one such index, the price-to-cost markup for short-term energy, by calculating the ratio of the markup of prices in California's *short-term* energy markets to the estimated competitive price. A perfectly competitive market would be indicated by the index equal to zero (no percentage markup). Since December 2001, short-term markup has stabilized at approximately 10 percent of costs, well below its all-time high of approximately 130 percent in April 2001, during California's energy crisis. Markup indices for March through May 2002 are estimates only until actual purchase prices are available from the Department of Water Resources' California Energy Resources Scheduling Division (CERS).The following table shows the price-to-cost markup in short-term energy (which does not include long-term forward energy contracts) since late 2000.

Figure 3. Price-to-Cost Markup in Short Term Energy



II. Ancillary Services

The ISO monitors AS prices and volumes by service type and market. Costs for AS rose approximately 18 percent between April and May, returning to February levels. Nonetheless, AS cost as a percentage of total energy cost remains relatively low at about 2 percent. The average prices of upward and downward regulation services (RU and RD) in the ISO's day-ahead market were $14.08/MWh and $16.51/MWh in May, up 11 and 61 percent from April levels, respectively. Average volumes of 468 MW and 457 MW, respectively, were similar to those seen in April. Average spinning and non-spinning reserve prices were $4.43/MWh and $1.30/MWh, up 30 and 78 percent, respectively. The average volume of spinning reserves increased to 714 MW in May, up 7 percent since April. The average volume of non-spinning reserves was 663 MW in May, similar to that seen in April. The following table shows AS prices and volumes by market.

Table 3. AS Prices and Volumes by Market

	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	$ 14.08	$ 16.68	$ 14.31	468	46	91%
Regulation Down	$ 16.51	$ 7.62	$ 15.58	457	54	89%
Spin	$ 4.43	$ 9.83	$ 4.67	714	33	95%
Non-Spin	$ 1.30	$ 2.12	$ 1.35	663	42	94%
Replacement	$ 0.08	$ 0.62	$ 0.12	62	5	92%

III. Inter-zonal Congestion

There was an increase in congestion costs in May compared to recent months, due primarily to outages and derates of major transmission lines. The California-Oregon Intertie (COI) incurred approximately $1.2 million in day-ahead congestion costs in the import direction on May 29, when that path was derated from its usual transmission capacity of 3,200 MW to 1,600 MW due to a fire under the Olinda-Captain Jack 500kV line. Similarly, when Palo Verde was derated from 2,700 MW to 1,700 MW for eight hours on May 25-26 due to scheduled maintenance, the path incurred over $978,000 in day-ahead congestion costs.

The chart below shows that congestion costs for 2002 have been substantially lower than those incurred in 2001. The table that follows shows day-ahead congestion statistics for May, including the percentage of hours during which paths are congested and average congestion price, in peak, off-peak, and all hours. The table also shows total day-ahead and hour-ahead congestion costs for each path.

Figure 4. Monthly Congestion Costs in 2001 and 2002

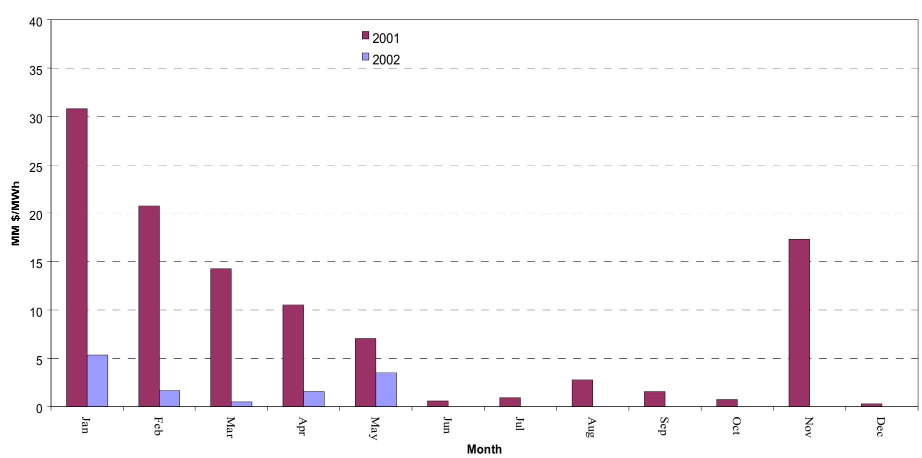


Table 4. Day-Ahead Interzonal Congestion Frequencies and Prices and Total Congestion Costs for May 2002

Branch Group and Direction	Peak Congestion Pctg.	Off-Peak Congestion Pctg.	All-Hour Congestion Pctg.	Avg. Peak Congestion Price	Avg. Off-Peak Congestion Price	Avg. All-Hours Congestion Price	Total Congestion Cost (DA + HA)
Cascade (Import)	3.2%		2.2%	52.01		52.01	$66,598
COI (Import)	11.9%	4.0%	9.3%	14.28	0.01	12.21	$2,335,850
Eldorado (Import)							$99,100
Mead (Import)							$18,741
NOB (Import)	6.1%	0.0%	4.0%		0	0	$179,870
Palo Verde (Import)	0.0%	3.2%	1.1%	52.01		52.01	$980,656
Path 15 (South-to-North)	0.0%	2.0%	0.7%		0	0	$180,268
Path 15 (North-to-South)	3.2%	0.0	2.2%	16.56		16.56	$42,064
Path 26 (South-to-North)	0.0	1.6%	0.5%		27.25	27.25	$116,793
Path 26 (North-to-South)	1.4%	0.0%	0.9%	19.14		19.14	$268,964
Silver Peak							$2,106
Sylmar (AC) (Import)	3.%	3.2%	3.2%	249.72	249.72	249.72	$374,936
Victorville (Export)							$219,529
Total Costs							**$4,885,475**

IV. Summary of Market Costs

DMA estimates that wholesale cost to load for energy and AS totaled $800 million in May, or an average of $41/MWh, similar to the average price in April. These stable costs can be attributed to strong hydro conditions in the Pacific Northwest and low natural gas prices in California. Average wholesale costs have remained below $50/MWh since October 2001. The following tables show costs for wholesale energy and AS for 2002 to date, and summaries for years 2001 and earlier.

Table 5a. Monthly Costs for Wholesale Energy in 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$)	Avg Cost of Energy ($/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	$ 785	$ 800	$ 40	$ 0.76	1.9%	$ 41
Total 2002	93,460	90,844	$ 3,726	$ 40	$ 67	$ 3,766	$ 3,834				
Avg 2002	18,692	18,169	$ 745	$ 8	$ 13	$ 753	$ 767	$ 40	$ 0.72	1.8%	$ 41

* 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

*****March, April, and May forward costs (and resulting totals) are estimated. Values in July report will include true-up and may differ from values shown here.

Table 5b. Annual Costs for Wholesale Energy through 2001

	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 2001	227,024	$ 21,248	$ 4,162	$ 1,346.09	$ 25,409.97	$ 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 only:

* Sum of hour-ahead scheduled costs. 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

All years:

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

V. Firm Transmission Rights

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

FTR scheduling. On some paths, FTRs were used to establish the scheduling priority in the day-ahead markets. As shown in the following table, a high percentage of FTRs was scheduled on some path (e.g. 77% on Eldorado, 71% on IID-SCE, 65% on Palo Verde, and 100% on Silver Peak, all in the import direction). FTRs on those paths are mainly owned by Southern California Edison Company (SCE1). FTRs on most other paths were primarily used for their financial entitlement to transmission usage charges. FTR concentration levels do not appear to raise concerns of market manipulation at the present time.

Table 6. FTR Scheduling Statistics

	Import								Export	
	COI	ELDORADO	IID-SCE	MEAD	NOB	PALOVRDE	SILVERPK	VICTVL	MEAD	PATH26
MW FTR Auctioned - Imp	658	793	600	478	698	1167	10	926	456	1566
Avg. MW FTR Sch. - Imp	80	609	427	56	6	762	10	35	14	103
Max MW FTR Sch. - Imp	200	710	432	220	155	805	10	78	150	514
Max Single SC FTR Schedule	175	710	432	178	150	579	10	50	100	514
% FTR Schedule - Imp	12%	77%	71%	12%	1%	65%	100%	4%	3%	7%

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

FTR per-Megawatt Revenue. The following table summarizes FTR revenue per MW for May 2002. FTR revenues on COI and Paloverde were relatively high in the import direction (e.g. $888/MW on COI and $839/MW on Paloverde).

Table 7. FTR Revenue Per MW, May 2002 ($/MW)

COI	IMPORT	$888
Eldorado	IMPORT	$26
Mead	IMPORT	$22
Palo Verde	IMPORT	$839
Path 26	IMPORT	$133
Path 26	EXPORT	$134
Victorville	EXPORT	$249

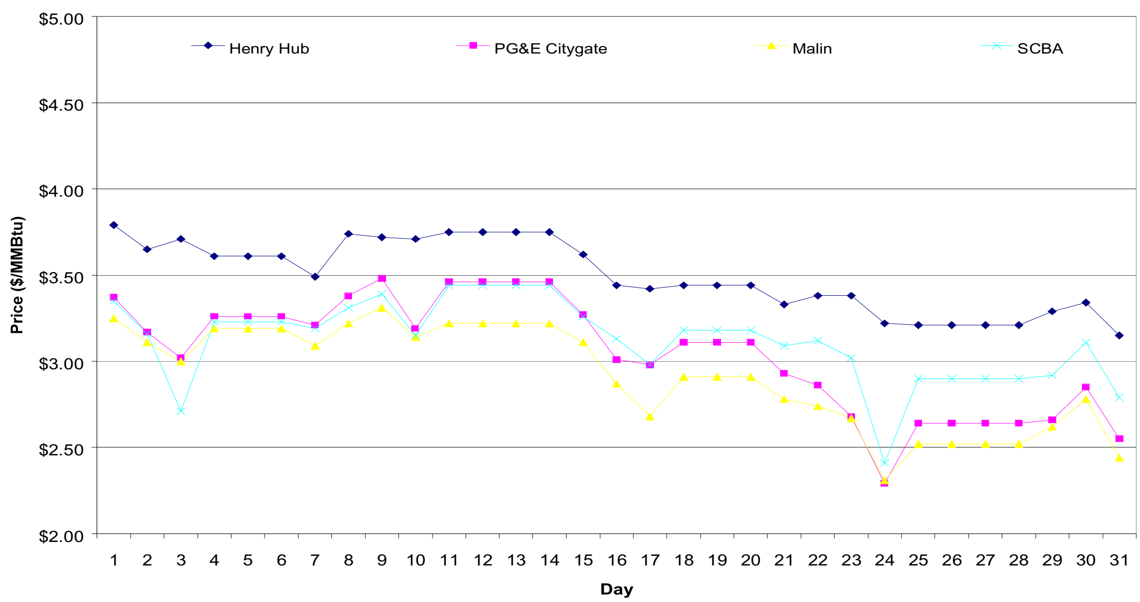
VI. Natural Gas Markets

Spot natural gas prices were substantially unchanged during the first half of May. Prices followed a decreasing trend during the latter half of the month, as mild weather and strong hydro conditions eased demand for gas-fired electric generation. High temperatures in the Southern United States kept Henry Hub prices in the $3.50 to $3.80/MMBtu range, at least $0.25/MMBtu greater than California hub prices. California prices weakened slightly during the first three days of May, but regained strength during the second week of May due to gains in the natural gas futures contract market.

After May 14, temperatures in the Southern U.S. decreased as a cold front moved through the area, decreasing demand for natural gas. By May 16, prices at Henry Hub dropped to below $3.50/MMBtu and remained in the $3.15 to $3.50/MMBtu range for the remainder of May. Prices in California fell from nearly $3.50/MMBtu on May 14 to below $3.00/MMBtu on May 16. On May 24, California hub prices markedly dropped to below $2.45/MMBtu due to weak futures prices, mild weather, and the load decrease associated with the Memorial Day weekend. Prices remained within the $2.50 to $3.00/MMBtu range between May 25 and May 29. Prices increased as air conditioning load increased leading up to May 30, but decreased sharply on May 31. By the end of May, Henry Hub spot natural gas prices were at $3.15/MMBtu, while California hub prices ranged from $2.44 to $2.79/MMBtu. Average bid week prices for June were $2.88, $2.62, and $2.65 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 10%, 11%, and 14% from May bid week prices.

The following chart shows daily gas prices at California delivery points and Henry Hub for May.

Figure 5. Natural Gas Trading Hub Prices for May 2002



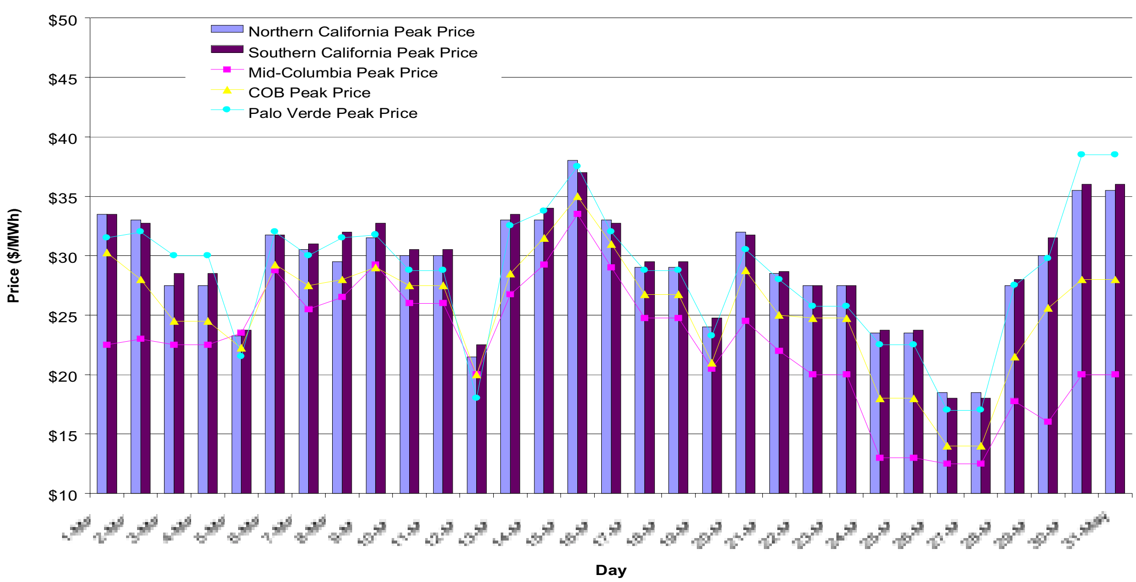
VII. Regional Electric Markets

Regional peak day-ahead forward electricity prices began May in the range of $30 to $35/MWh, with the exception of prices at the Mid-Columbia hub, which began May at $23/MWh, owing to continued supply of hydroelectric power from the Northwest and the return of the California-Oregon Intertie (COI) to full capacity. Cool weather also had the effect of delaying runoff, which decreased hydroelectric production in the early days of the month. This decrease in supply, in conjunction with higher gas prices, caused the Mid-Columbia price to increase sharply on May 6 to the $30/MWh level. Prices remained at this level until May 12, after which they dropped due to reduced weekend demand. On May 15, prices rebounded to the range of $34 to $37/MWh, due to forecasted warming in the Southwest. Electricity prices quickly fell to between $20 and $25/MWh on May 19 as natural gas prices fell $0.50/MMBtu or more on spot and futures markets.

As refueling at the San Onofre Nuclear Generating Station #2 (1,070 MW) began, California and Palo Verde prices reached $30/MWh, but fell steadily until May 28. At this time, cooler weather moved into California and Arizona, softening demand, and natural gas prices remained at lower levels. Also, Mid-Columbia and California Oregon Border prices fell in excess of $5/MWh on May 24, reaching monthly lows below $15/MWh, as runoff returned to normal levels in the Columbia River Basin and other fish migration measures in the Northwest increased hydroelectric generation. After May 28, sharply warmer temperatures in the Southwest and in California put upward pressure on prices. Between May 28 and May 31, Palo Verde prices increased by over $20/MWh, ending the month at $38.50/MWh.

The following chart shows regional hub prices for May.

Figure 6. Western Regional Day-Ahead Bilateral Market Prices for May 2002[4]



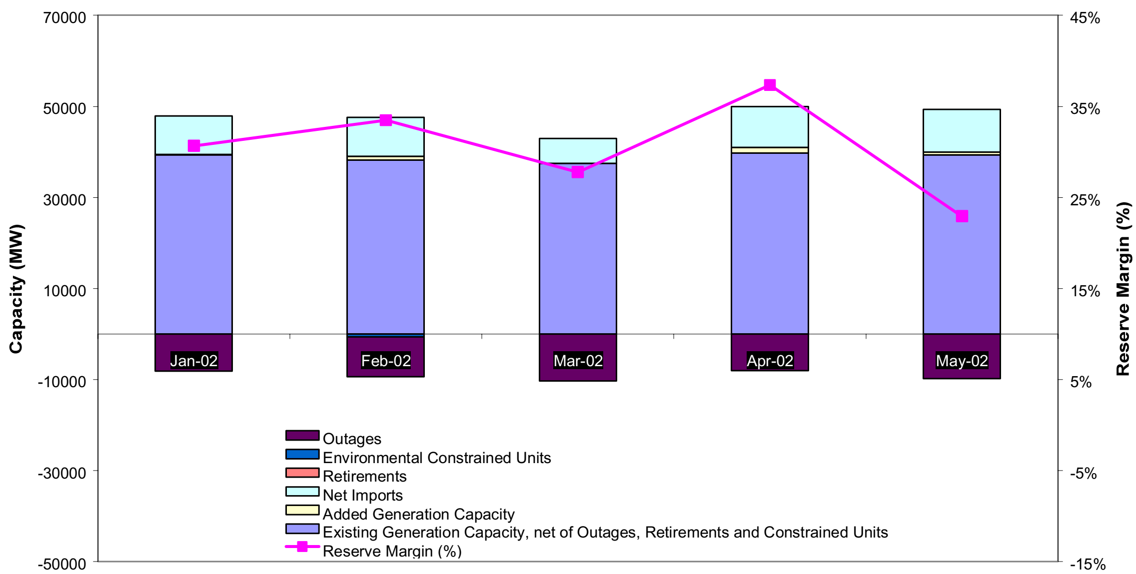
VIII. Reserve Margins

The Department of Market Analysis (DMA) monitors the reserve margin in California's energy markets. Reserve margin, or difference between available generating capacity and peak load, is an indicator of market power potential. An SC with a total portfolio capacity in excess of the reserve margin can be considered pivotal, and in some circumstances may have the ability to

[4] Regional prices represent day-ahead firm peak energy prices. California area prices are not ISO real-time prices.

withhold generation (or bid its generation at excessive prices). The following chart compares peak load with available generating resources, including net imports, less outages, to date in 2002.

Figure 7. Average Monthly Net Dependable Capacity vs. Reserve Margin, 2002



IX. CERS Long-Term Contracts Update

By May 2, CERS had successfully renegotiated 15 long-term power purchase agreements with Calpine Energy Services, Constellation Power Source, Whitewater Energy Corporation, Capitol Power, and Calpeak Power. CERS also terminated one contract with Calpeak. As a result, CERS has 55 agreements outstanding with 26 suppliers for terms of up to 11 years in duration. The primary results of renegotiations were increases in the quantities of dispatchable and firm capacity under the CERS supply portfolio. Firm energy now comprises up to 6,586 MW (56 percent) of peak deliveries and 4,626 MW (56 percent) of off-peak deliveries under the renegotiated CERS contracts, compared to 4,715 MW (40 percent) of peak deliveries and 3,010 MW (37 percent) of off-peak deliveries prior to the renegotiations. Total firm and non-firm capacity increased 189 MW (1.5 percent) in peak hours, and 56 MW (0.7 percent) in off-peak hours.

X. Demand Response Programs

Utilities have been implementing programs to stimulate demand-side price response. Approximately 200 MW of load are now participating in the statewide Demand Bidding Program, which enables load to be curtailed during stage emergencies. California's 20/20 program has also been reinstated for summer 2002 for residential consumers. This program gives consumers that consume 20 percent less energy in summer 2002 than in 2000 to receive a 20% credit on their electric bill. According to the Pacific Gas and Electric Company, 34 percent of their residential customers qualified for a 20/20 credit in the summer of 2001. The ISO will continue to make every possible effort to assist in implementation of demand response programs whenever possible.

The ISO's Participating Load Program (PLP) allows loads to participate in the ISO's AS markets and also to bid into the BEEP Stack. Whereas generation would bid to increment or decrement output, PLP participants may offer to curtail or augment load in real time. By enabling load to bid prices at which they are willing to pay to increase consumption, this program could be especially beneficial, for example, in remedying the DEC problem discussed earlier in this Report. Participation in past summers has varied from volumes of 800 MW bid in the summer of 2000, to fewer than 100 MW in the summer of 2001, due to adverse hydro conditions and creditworthiness issues. After the ISO receives approval from FERC for the 2002 Market Redesign (MD02) – which includes several flexibility enhancements for load – it will launch a broad awareness campaign highlighting new market opportunities for load participants.

XI. Issues under Review

Enron Memoranda. DMA staff continue to work with a variety of Federal and State legal and regulatory entities investigating the type of trading practices described in a series of internal Enron memoranda released last month.

Amendment 43. On June 11, 2002, FERC issued an Order accepting the ISO's proposal of Amendment 43 to its Tariff. This amendment allows importers of energy that bid into the BEEP Stack to be paid at the instructed energy price, even if the ISO changes its dispatch instructions within an hour of operation and the importer is unable to respond to the change. Previously, importers had been paid for energy at ten-minute prices. However, some importers have the capability only to provide energy on an hourly basis. The difference between those importers' hourly deliveries and the ISO's ten-minute dispatch instructions had been considered uninstructed deviations. Since incremental deviations are paid at the (often lower) ten-minute DEC price and decremental deviations are charged the (often higher) ten-minute INC price, importers could not be guaranteed favorable prices when bidding. Consequently, fewer importers bid into the BEEP Stack. The amendment should improve system reliability by increasing the volume of BEEP bids, as well as enhance the degree to which the ISO real-time market is competitive, and ultimately reduce cost to load. The rule change in the Amendment will expire September 30, 2002.

MD02 Filing. On June 17, the ISO completed and filed at FERC tariff language for implementing the long-term design elements of MD02. DMA participated in this process by reviewing draft tariff language and providing input on implementation details, particularly those relating to bidding activity rules and market power mitigation. The ISO also filed responses to stakeholder protests of the ISO's MD02 filing on May 1. Since many of these protests and comments received by FERC were directed at the market power mitigation provisions proposed in MD02, DMA has played a key role in drafting responses to those comments.

FERC Orders of May 15, 2002. DMA analysis point to serious potential problems with the following elements of the Orders issued by FERC on May 15. Some key concerns are summarized as follows.

FERC denied the ISO's petition to change the requirement that importers be required to bid energy into the BEEP Stack at prices different from $0/MWh. (See Market Analysis Report for March 2002.) The ISO had proposed that importers be permitted to submit nonzero bids to signal prices they are willing to accept to provide energy, but be ineligible to set the BEEP MCP. Though the proposal had received a consensus endorsement from shareholders, FERC denied ISO's petition out of concern that it might facilitate megawatt laundering. The zero-bid requirement, which has reduced the volume of import bids into the BEEP Stack, may also have the effect of bestowing market power on generating resources within the ISO Control Area. Even though higher prices would attract importers back into the market at certain times, internal resources will still have a significantly greater ability to determine prices.

FERC also ruled that importers need not give the ISO the ability to review their generation schedules to be eligible to set the BEEP MCP. This ruling treats external resources preferentially, since they cannot be monitored by the ISO to ensure compliance with the "Must Offer" obligation, directed in FERC's Order of June 19, 2001.

FERC denied netting of market profits against minimum load cost compensation. As a component of the "Must Offer" obligation, generators are entitled to recover from the ISO the costs they incur to remain available. This requires that generating units remain on at minimum output, whenever they are not waived from the obligation by the ISO. The ISO had petitioned to pay generators only the availability costs that they had not recovered in profit from energy transactions. In its rejection of the ISO's petition, FERC asserted that a generator whose application to be waived from the obligation had been denied by the ISO is entitled to apply market profits to the recovery of fixed costs, rather than to the recovery of availability costs. DMA has questions concerning this decision. A generator that had successfully obtained a waiver would remain shut down, and thus would have no market profit at all. It follows that any profit is incidental, in the sense that the generator would not have received it if its request to shut down were approved, and, in the opinion of DMA, should be applied to availability costs.

FERC reiterated that the soft price cap be recalculated whenever operating reserves fall below 7 percent of load. As noted previously in this Report, this would require recalculating of the soft price cap, and likely cause it to fall from its current level of $91.87/MWh to approximately $45/MWh. This likely would result in extraordinary levels of as-bid and OOM procurement, and compromise system reliability. Thus, the ISO is seeking further clarification on this matter from FERC.