California Independent
System Operator

CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: November 25, 2003

Re: **Market Analysis Report for October 2003**

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

Executive Summary

Systemwide loads increased 5.4 percent in October 2003 beyond those in October 2002, due to unseasonably warm weather throughout the State, particularly in southern California. Energy schedules exceeded actual load in most hours, as the ISO issued minimal energy dispatches in the incremental direction, and a significant volume of dispatches in the decremental direction, to balance generation with actual loads in real time. Prices for incremental balancing energy increased 11 percent from September 2003 levels, while decremental prices decreased just over 14 percent. Overall, the ISO's real-time balancing market continues to perform well, as actual prices were within 15 percent of competitive price estimates in October.

Transmission derates and outages due to fires in Southern California in the final week of October created significant congestion within the SP15 zone in real time. The ISO dispatched a significant volume of energy out of merit in order to work around this congestion. In October, the ISO incurred incremental and decremental redispatch costs of approximately $3.9 million and $3.8 million, respectively. In addition, the ISO retained capacity within the control area on minimum load to assure reliability in Southern California during periods in which the fires affected transmission lines.

Average prices for ancillary reserve services were moderate compared to those in the summer of 2003; however, the ISO was frequently unable to procure the required ancillary services capacity from the hour-ahead market. To address this problem, the ISO was forced to call upon RMR contracts to supply operating reserves that could not be procured through the available bids from the A/S markets. Please see the section on Issues under Review for a discussion of incentives and bid insufficiency in the A/S markets.

Usage costs due to congestion on key transmission paths between California and neighboring areas totaled $4.2 million in October, a significant increase from the $1.8 million reported in September. Approximately $3 million of this congestion was incurred on Path 26, a primary artery between Northern and Southern California, in the North-to-South direction. The recent wildfires in Southern California had minimal direct cost impact on the forward interzonal congestion markets.

Due to low prices in the western wholesale power market over the past several months, owners of several units constructed in the 1950s and 1960s have elected to retire or mothball approximately 1,400 MW of generation within the ISO Control Area since October 1. The ISO will be monitoring the effect of unit retirement going forward, as a significant quantity of older, inefficient capacity in California has not been sold under long term contracts. Future long-term procurement rules currently under proceedings at the California Public Utilities Commission will likely have a significant effect on the future of this trend.

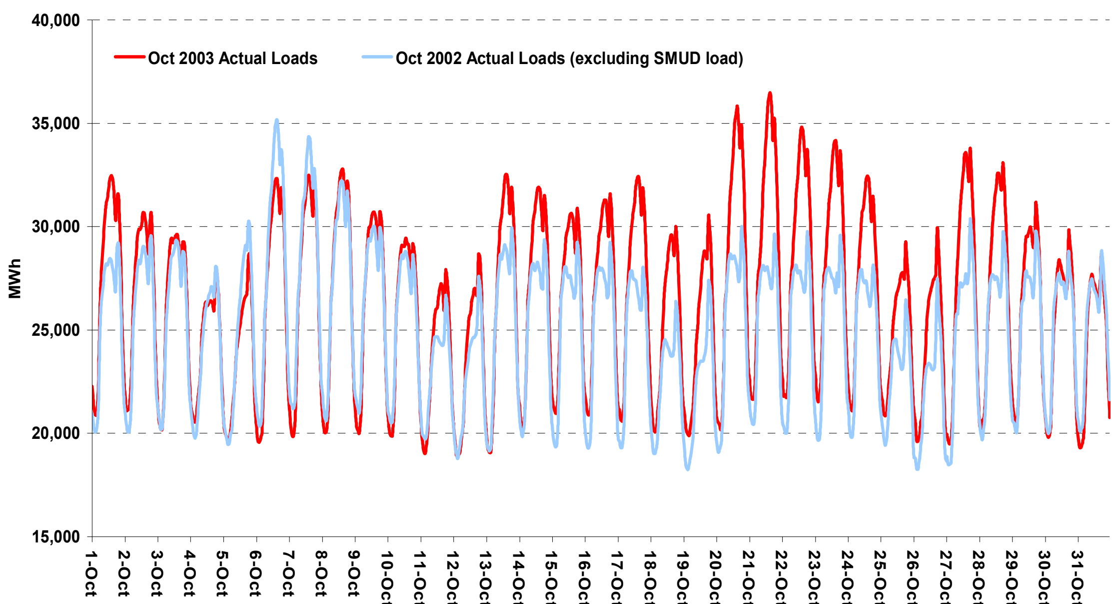
I. Market Trends

The Southern California heat wave caused loads to spike in SP15 between October 21 and 24.

Systemwide load averaged 26,476 MW in October 2003, up 5.4 percent from the October 2002 average, due in part to unseasonably warm weather throughout the State and particularly in Southern California. The monthly peak load reached 36,480 MW on October 21, between 3:00 and 4:00 p.m., up 3.7 percent from the October 2002 peak.

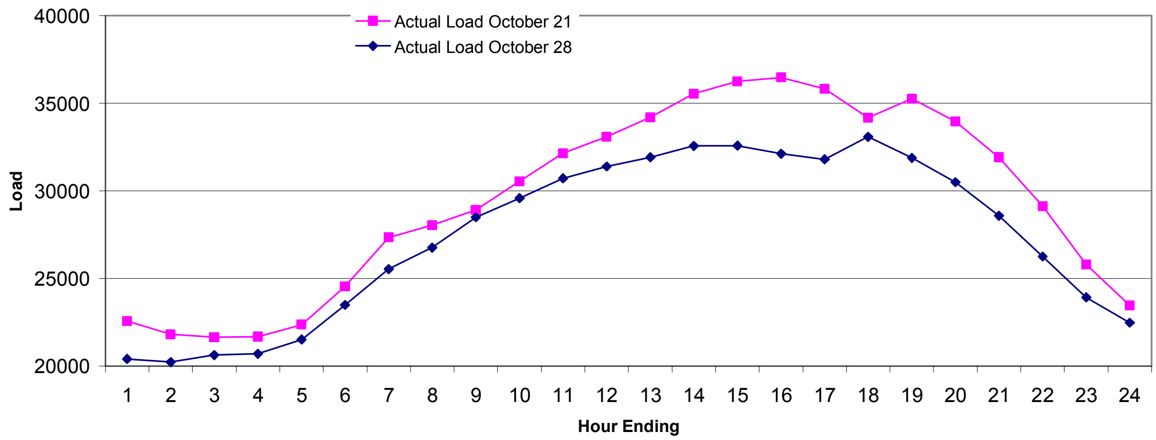
The aforementioned heat wave in Southern California, whose Santa Ana winds eventually caused the spread of several wildfires, pushed loads within the SP15 area to all-time peak levels for the month of October. On October 20, between 1:00 and 2:00 p.m., the Southern California area load reached 20,471 MW, its highest level of record in October. The SP15 record peak load stands at 24,610 MW, set September 5, 2003, between 3:00 and 4:00 p.m. The following chart shows hourly loads in October 2003, compared to those in October 2002.

Figure 1. Actual Loads: October 2003 v. October 2002



Cold weather in the final week of the month and the return to Standard Time caused a shift in load patterns, from the summer afternoon-peaking pattern to the winter evening-peaking pattern. For example, on Tuesday, October 21, the peak hour of the day was hour ending 16:00 (between 3:00 and 4:00 p.m.), due to demand driven by air conditioning during the warmest hours of the day. In comparison, on the following Tuesday, October 28, the peak hour of the day was hour ending 18:00 (between 5:00 and 6:00 p.m.), due to demand driven by residential heating and lighting. This evening peak should become more pronounced in the later months of the year. The following chart shows actual loads on October 21 and 28, 2003.

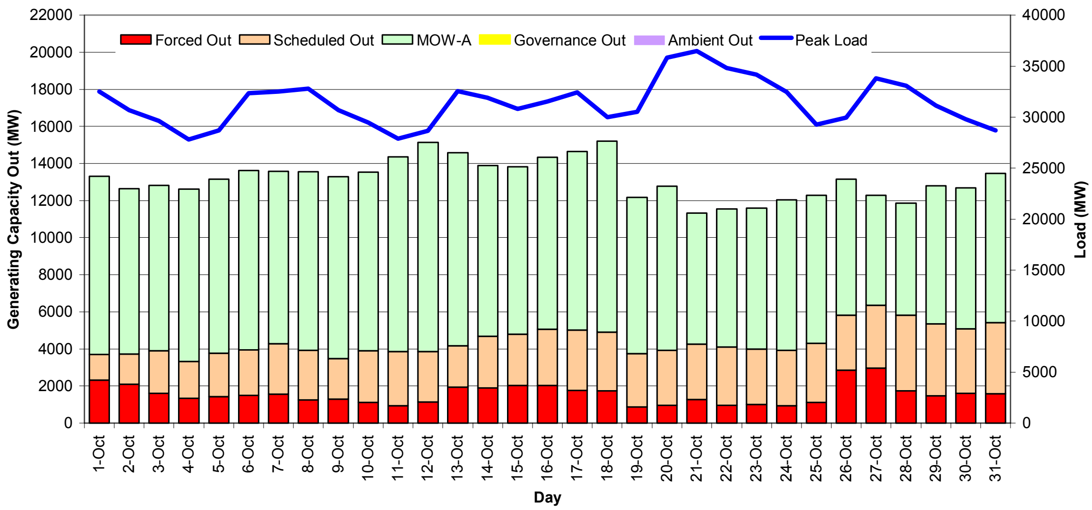
Figure 2. Change in Load Daily Profiles
Hourly Loads for October 21 and 28, 2003



Planned outages increased in October, as generators went off-line for seasonal maintenance. On Wednesday, October 1, approximately 1369 MW was unavailable due to planned outage. This number increased to 3870 MW by Wednesday, October 29. Fires in the last week of October caused forced outages of at least 1200 MW of capacity in Southern California on October 26; these units were all restored to service by October 28. The fires also caused the ISO to reduce significantly the amount of capacity in Southern California out on waivers from the Must-Offer Obligation[1] in its efforts to maintain operational stability of the system during the last week of October, as discussed below in the section on real-time procurement. The following chart shows daily average MW out by outage type in October.

[1] Federal Energy Regulatory Commission, "Order on rehearing of monitoring and mitigation plan for the California wholesale electric markets, establishing west-wide mitigation, and establishing settlement conference," issued June 19, 2001, 95 FERC ¶ 61,418, and subsequent Orders.

Figure 3. Daily Average Outages in October



II. Real-Time Balancing Energy Market

Scheduled energy often exceeded actual load in most hours, causing the ISO to dispatch a significant amount of decremental generation to balance the system.

Transmission derates due to fires in Southern California in the final week of October caused significant congestion within the SP15 zone in real time.

Energy subject to minimum-load cost compensation was twice as high in October 2003 as in October 2002 due to the fires.

The ISO continues to make real-time redispatch calls to resolve intrazonal congestion between new generation in Mexico and load in San Diego, and to work around remaining derates attributed to the Vincent Substation fire in March 2003.

As in recent months, scheduled energy has been more than sufficient to supply load. Consequently, the ISO continues to dispatch more decremental than incremental balancing energy, by a four-to-one margin. While the average incremental market-clearing price increased to $75.06/MWh in October from $67.54/MWh in September, total instructed energy decreased to 102 GWh from 120 GWh, resulting in a decrease in total incremental instructed market energy costs.

Meanwhile, the average decremental price, the price suppliers pay to the ISO when permitted to decrease generation in periods in which schedules exceed actual load, decreased to $18.10/MWh in October, from $21.16/MWh in September. All else equal, this increases total costs to load. An increase in total instructed decremental energy to 434 GWh in October, from 411 GWh in September, compounded this increase. The table immediately below shows average real-time incremental and decremental energy prices in October, in addition to the volumes of total instructed energy, and system loads and underscheduling in October. The chart that follows shows monthly average real-time balancing energy prices and volumes of dispatch instructions, for the twelve months ending in October.

Figure 4. Monthly Average Real-Time Balancing Energy Prices And Average Volumes of Dispatch Instructions through October[2]

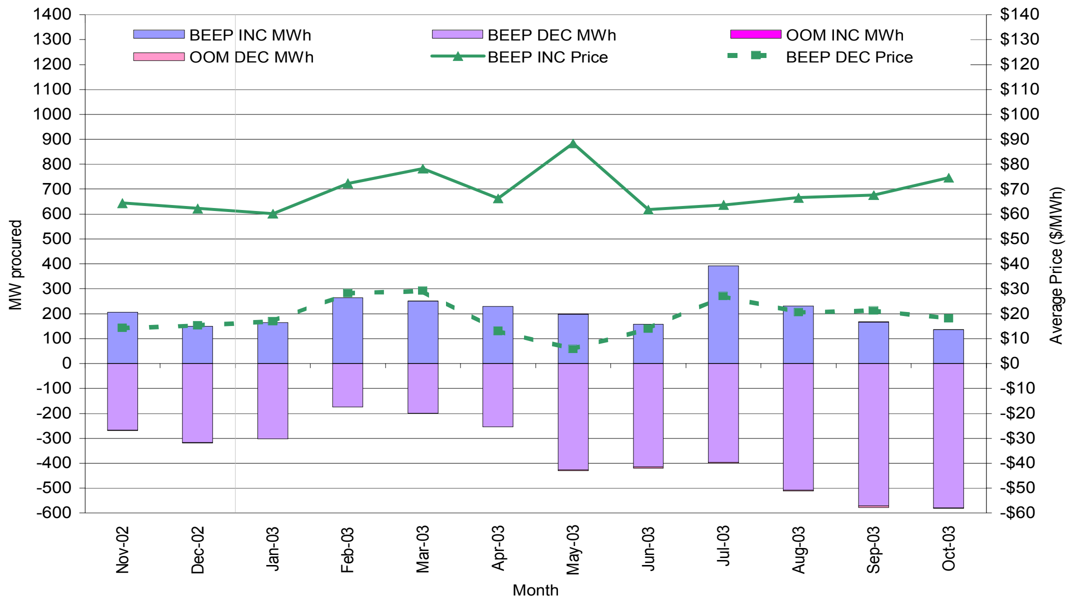


Table 1. Monthly Average Real-Time Balancing Energy Prices, Total Instructed Energy, Average System Loads, and Underscheduling, in October

	Overall Avg. Real-Time Price and Total Energy		Avg. System Loads (MW) and Pct. Underscheduling
	Inc.	**Dec.**	
Peak	$ 79.84	$ 20.60	28,836 MW
	80 GWh	322 GWh	0.5%
Off-Peak	$ 57.94	$ 10.91	21,578 MW
	22 GWh	112 GWh	-0.6%
All Hours	$ 75.06	$ 18.10	26,476 MW
	102 GWh	434 GWh	0.2%

[2] "BEEP" energy is procured from bids into the ISO's Balancing Energy Ex-Post Price computerized auction market (the "BEEP Stack"). In the event that the ISO is not able to dispatch sufficient volumes through the BEEP Stack, it can procure the remainder through a last-resort manual procedure known as Out-of-Market (OOM) procurement, pursuant to ISO Operating Procedure M-403.

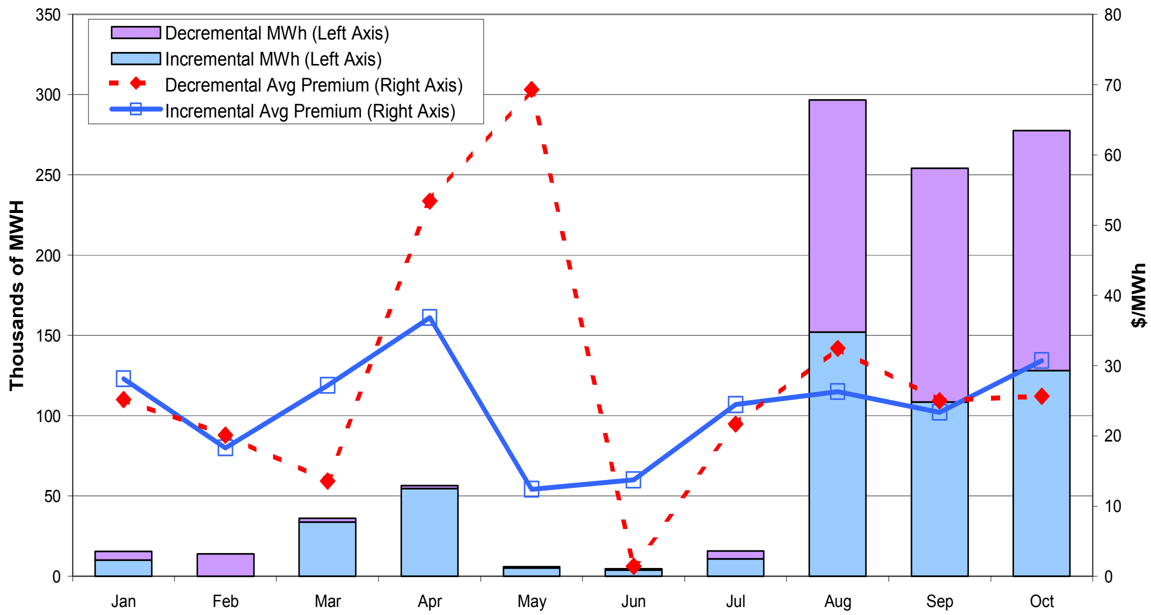
Intrazonal (within-zone) Congestion in SP15. Several problems necessitated out-of-sequence (OOS) procurement in October. These include:

- *Southern California Fires:* The fires in Southern California caused a number of transmission lines to be taken out of service intermittently. The ISO dispatched specific generation units out of sequence to compensate for this lack of transmission access to load.
- *Vincent Transformer Banks:* Due to a fire in March, only two of the three 500/230 kV transformers have been in reliable service at the Vincent substation, a key transmission interface between Northern and Southern California. The replacement of the third bank was tested on October 4, but peripheral installation work continues, resulting in only intermittent availability. To manage the Vincent congestion, the ISO must make incremental OOS calls to generators within SP15.
- *Sylmar Bank overloads:* Excess generation in Southern California Edison's service territory resulted in overloading of the banks at the Sylmar substation, a key interface for transmission into Southern California.
- *South of Lugo:* The ISO manages congestion south of the Lugo Substation, a key interface between generation in Nevada and Arizona and load in Southern California, by incrementing generation OOS within Southern California.
- *Miguel*: The ongoing congestion caused by a lack of transmission capacity into the Miguel Substation, the primary interface between new generation in Mexicali, Mexico, and load in San Diego, resulted in further incremental calls to generation units in SP15
- *Seasonal Outages:* A number of transmission lines were out of service for seasonal maintenance. In particular, the Pacific DC Intertie (also known as the North-of-Oregon Border Intertie, or NOB) has been available only intermittently due to maintenance.

As in September, the ISO called upon bids OOS, in both the incremental and decremental directions, to manage intrazonal congestion. This congestion was caused primarily by the ongoing derate of the Vincent substation due to a fire on March 21, 2003, new generation in northern Mexico, and the recent fires in southern California. In October, the ISO dispatched 128 GWh of incremental OOS. This resulted in a net cost in excess of payments at the market-clearing price of approximately $3.9 million (also known as the *redispatch premium*), or an average payment of $31.70/MWh above the market-clearing price. The ISO dispatched 149 GWh of decremental OOS, with redispatch premiums totaling approximately $3.8 million, or approximately $26/MWh.

Local market power mitigation of incremental dispatches through Automatic Mitigation Procedures (AMP LMPM) resulted in savings of $331,305, or approximately 4.3% of the total redispatch premium. During competitive market conditions we would expect the redispatch premium to be low. As shown in Figure 5 below, the redispatch premium for OOS dispatches has been at a moderate level of $20 - $30/MWh for the past few months. However, the OOS dispatch volumes for both incremental and decremental energy have been high since August resulting in significant OOS redispatch costs.

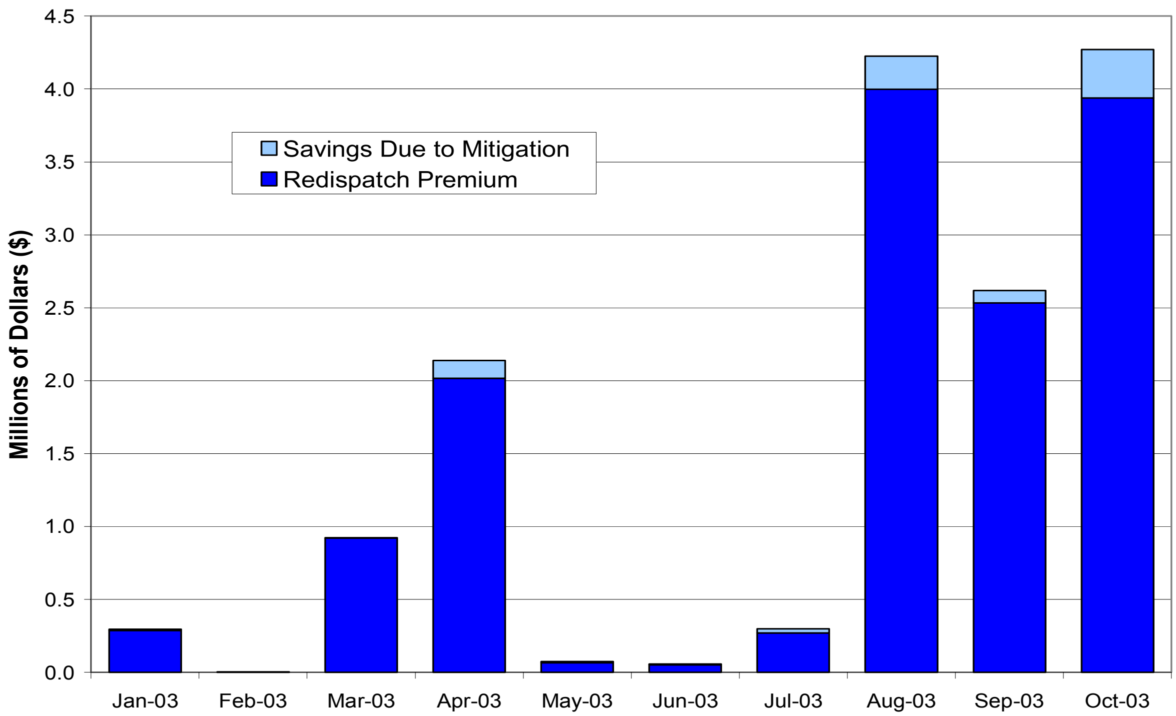
Figure 5. Out-of-Sequence Volumes and Average Redispatch Premiums



Under the current structure for local market power mitigation, an out-of-sequence dispatched bid is mitigated whenever it is at least the minimum of $50/MWh above or twice its respective *reference level,* a unit-specific index based upon that unit's bids and sale prices in the most recent 90-day period. The current local market power mitigation structure has resulted in minimal bid mitigation. Since the beginning of January 2003 there has been a total of approximately $30.5 million of gross OOS incremental costs. The current mitigation structure has resulted in approximately $817,259 in cost reductions year-to-date (2.6% of gross cost or 5.5% of re-dispatch premium), due to incremental OOS bid mitigation.

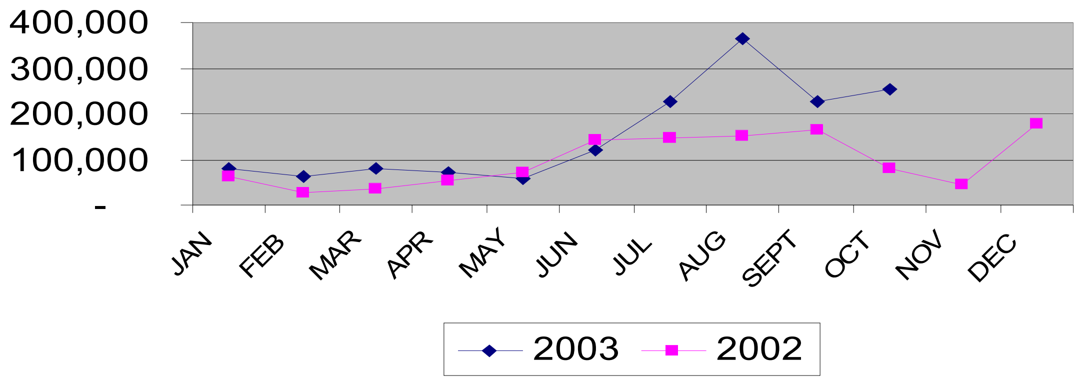
Figure 6 below shows AMP LMPM redispatch premiums in yellow and the savings due to mitigation of incremental dispatches in blue.

Figure 6. Incremental Redispatch Premiums and Savings due to Local market Power Mitigation



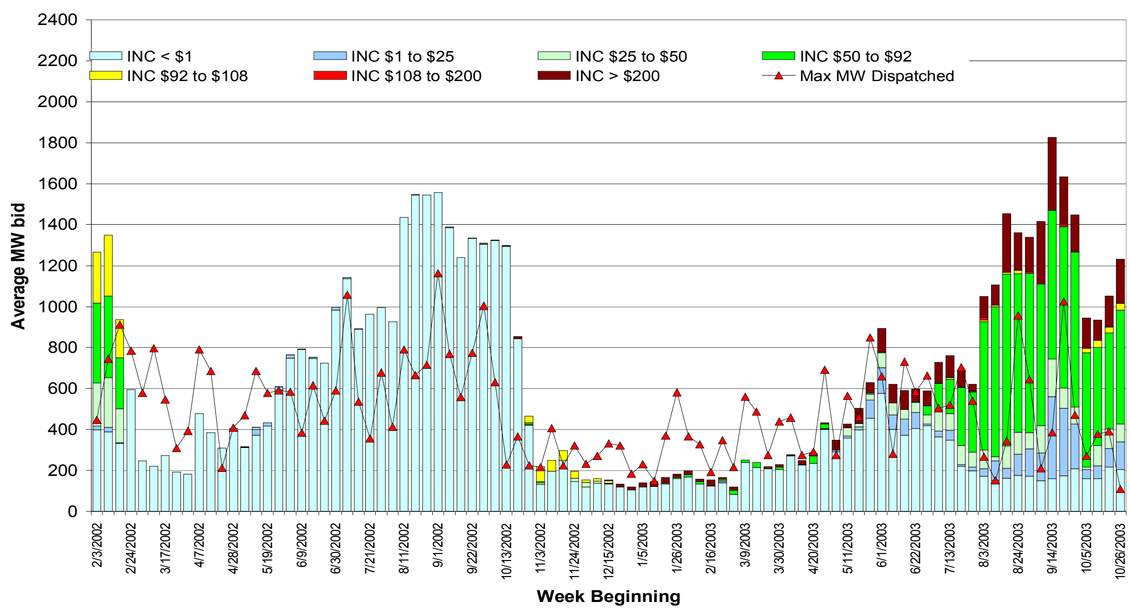
Minimum Load Cost Compensation. During the recent series of wildfires in Southern California, the ISO declared a transmission emergency to maintain reliability, and kept several units online and running at minimum load by declining applications to waive the Must-Offer Requirement. Pursuant to the FERC Must-Offer Order, these units are entitled to compensation for their minimum-load operating costs. Energy generated by minimum-load units was more than twice the level in October 2003 than in October 2002. The following chart shows energy generated by units kept on minimum load pursuant to the Must-Offer Obligation by month in 2002 and in 2003.

Figure 7. Energy Subject to Minimum Load Cost Compensation: 2002 v. 2003[3]



Import Bids in the Real-Time Market. The restriction that real-time bids from imports (also known as System Resources) bid incremental energy at a price of $0/MWh was lifted by FERC on June 25, 2003. Since that time, import bid volume increased to approximately 1400 MW by mid-September. However, import bid volume retreated to approximately 1000 MW in October, as suppliers in the Pacific Northwest were limited by derates of transmission into California. The following chart shows weekly average import bid volumes in the BEEP Stack through October.

Figure 8. Weekly Average Real-Time Import Bid Volumes through October

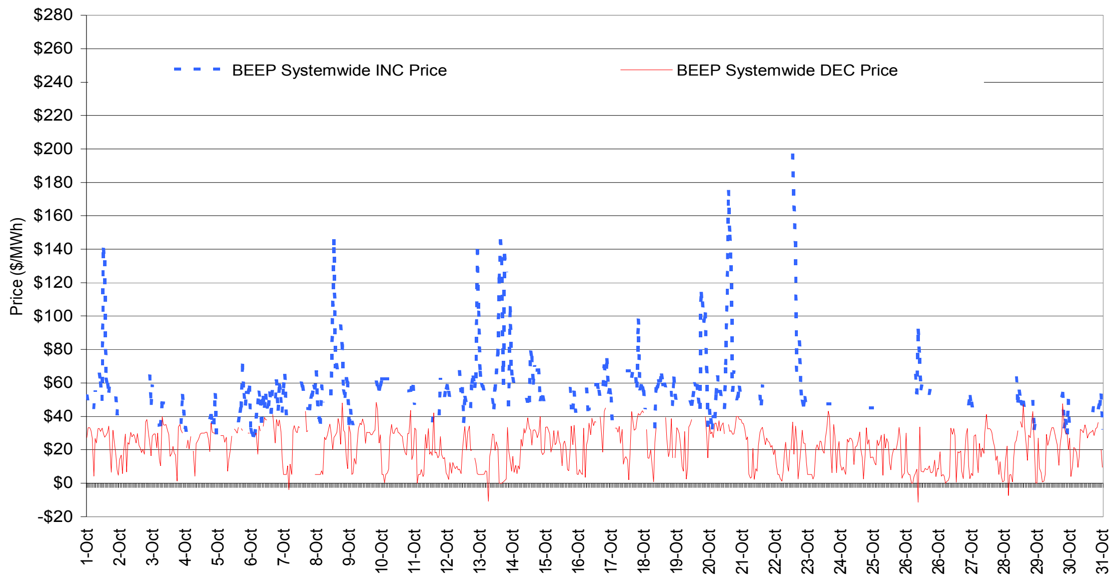


Review of Price Spikes and AMP Performance. Several price spikes occurred in October in markets for both incremental and decremental energy. These spikes were limited primarily to Southern California, during periods of congestion on Path 26.

[3] Actual minimum-load costs for October 2003 were not available at the time of writing. However, they are approximately proportional to the energy subject to cost compensation shown in Figure 7.

The Automatic Mitigation Procedures (AMP) were not activated during any price spikes, since the hour-ahead predictions of the real-time price were below the "price screen" threshold of $91.87/MWh in all cases. Price predictions in excess of $91.87/MWh caused AMP to activate in several hours on October 6. However, no price spikes actually occurred in these hours, so no units failed the AMP Conduct Test or were subject to mitigation. The following chart shows hourly average prices for real-time balancing incremental and decremental energy in October.

Figure 9. Hourly Average Prices for Real-Time Energy in October[4]



On October 1, a generator malfunction near San Diego caused a sudden loss of 705 MW. This necessitated several recovery actions, including the dispatch of ancillary services reserved for contingency situations, out-of-sequence procurement, and the awarding of instructed energy "as bid" to a resource that bid above the price cap of $250/MWh.[5] The real-time market-clearing price for incremental energy spiked to $145/MWh between 12:40 and 2:00 p.m., creating a market impact of approximately $62,000.

On October 7, between 3:50 and 5:00 a.m., a software problem concurrent with a scheduled derate of the Pacific DC Intertie (also known as the North-of-Oregon Border Intertie, or NOB) resulted in the dispatch of all units that had offered decremental energy. That is, the ISO instructed all units willing to decrease generation to do so in order to match generation to load. The price of decremental energy was set by the lowest-priced dispatched unit at -$25/MWh. That is, the ISO

[4] Prices are not shown for hours in which no energy was procured.
[5] Pursuant to the FERC Orders of 4/26/01 (95 FERC ¶ 61,115) and6/19/01 (95 FERC ¶ 61,418), and subsequent Orders, generating resources may bid to sell incremental energy above the price cap of $250/MWh. In the case that the ISO must procure energy from those resources, it will pay them "as bid", meaning they are paid directly and are not eligible to set the market-clearing price of the BEEP auction market. In this case, the market-clearing price is set by the highest-priced bid below $250/MWh. In this case, those bidders must provide verification that their bid prices are "just and reasonable".

paid all units in that period $25/MWh to decrease output. The market impact of this spike was approximately $15,000.

On October 8, between 12:40 and 2:00 p.m., the real-time incremental price ranged between $125.86 and $145/MWh within Southern California. Pursuant to ISO procedure, the dispatch algorithm skipped ancillary services bids reserved for contingency situations. The market impact of this spike was approximately $105,000.

On October 19, the real-time incremental price ranged between $100 and $125.86/MWh intermittently between 6:30 and 9:30 p.m., due to problems with ramp planning during a forced outage of the Eldorado-Lugo and McCullough-Victorville interties, limiting transmission into Southern California. The market impact of this spike was approximately $200,000. Because the predicted price was below $91.87/MWh, AMP was not activated.

On October 20, a large generator in Southern California relayed, causing a loss of 583 MW. This, combined with declined dispatch instructions, caused the Southern California real-time incremental price to range between $145 and $193.12/MWh from 1:30 to 4:40 p.m., and the Northern California price to range between $115 and $141 from 2:10 to 4:00 p.m. The ISO called upon ancillary services reserved for contingency situations, and also dispatched 6 MWh of energy as bid at a price above $250/MWh. The market impact of this spike was approximately $425,000. Because the predicted price was below $91.87/MWh, AMP was not activated.

On October 22, high loads within Southern California and transmission congestion into that region caused the real-time incremental energy price to range between $165.25 and $196.26/MWh between 1:50 and 3:40 p.m. In addition, the ISO procured 35 MWh of energy as bid above $250/MWh. In the dispatch sequence, the ISO skipped bids reserved for contingency situations. The market impact of this spike was approximately $275,000. Because the predicted price was below $91.87/MWh, AMP was not activated.

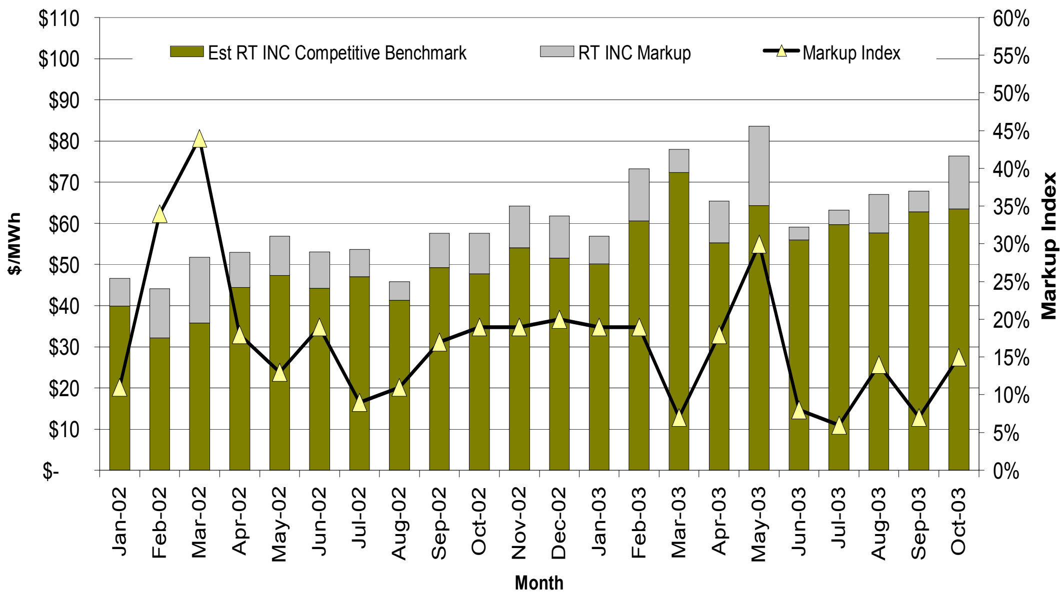
On October 29, the decremental price spiked to -$20/MWh between 2:20 and 3:00 a.m., as all internal resources available to be decremented were instructed to do so. Since many resources typically are shut down or brought to minimum operating points during low-load periods, such as this particular time, few resources were available for decrementation. The market impact of this spike was approximately $34,000.

Market Competitiveness. One measure of market power, or the ability of one or more sellers to maintain prices above those that would occur in a competitive market, is price-to-cost markup. The market for real-time incremental instructed energy exhibited an increase in the ISO's index of price-to-cost markup in October. Actual real-time prices averaged 15 percent above estimates of competitive prices in October, compared to approximately 5 percent in September. In dollar terms, this share of energy costs attributable to real-time incremental markup totaled approximately $1.3 million. The bulk of the markup occurred during a small number of price spikes.

The Department of Market Analysis is currently using a temporary index focused solely on the real-time market until day-ahead energy cost information can be obtained from the California investor-owned utilities. This real-time index is a conservative estimate of market power, because it includes only units that were dispatched by the ISO, as discussed at some length in the Market

Analysis Report dated September 19, 2003. It does not include the market impacts of either bidding high prices to avoid being dispatched by the ISO's real-time market (also known as economic withholding), or the deliberate prolonging of generator outages (also known as physical withholding). The following chart shows temporary price-to-cost markup in real-time incremental balancing energy through October.

Figure 10. Temporary Real-Time Markup Index through October[6]



Much of the monthly markup can be attributed to a few key price spikes. In particular, approximately 22.6 percent of the total dollars of markup for the month of October was incurred during the four hours of the spike on October 20, and another 22.7 percent was incurred during the three hours of the spike on October 22. The single hour of operation in October with the greatest share of total dollar markup was between 2:00 and 3:00 p.m. on October 22, accounting for approximately 17.4 percent of the monthly total markup, or $228,000.

III. Ancillary Services (A/S) Markets

Average prices for all services were moderate compared to prices during the summer of 2003.

Frequent bid insufficiency in the spin market caused deficiencies in the amount of operating reserves acquired through the market. ***RMR contracts were called to supply reserves that could not be procured through the A/S markets.***

[6] The real-time mark-up index is based on resources responding to dispatch instructions, and does not include the impacts of possible physical or economic withholding.

In many hours, A/S markets accepted the highest-priced bid offered, as bids were exhausted.

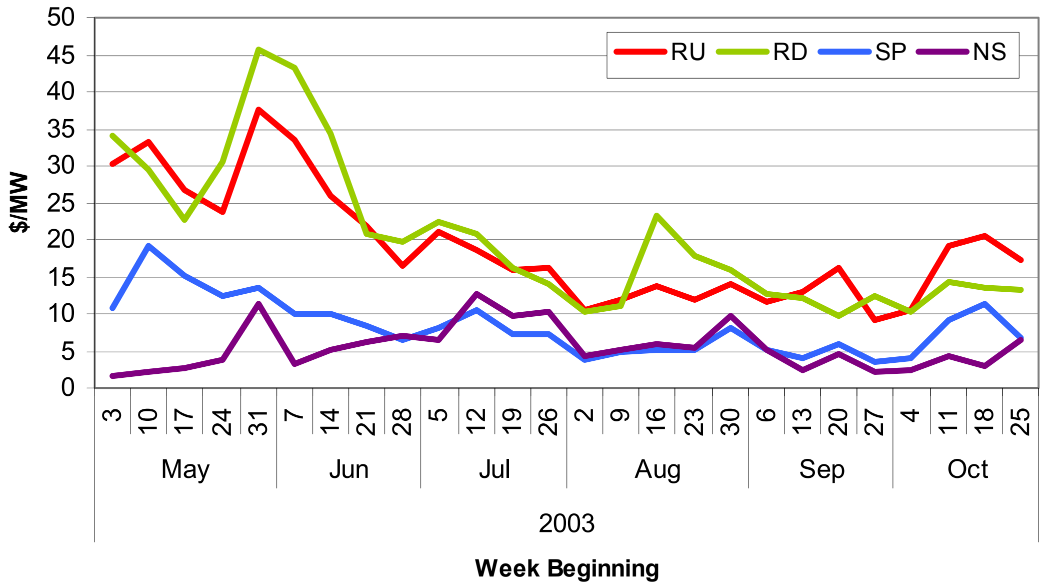
Market Prices. Although demand for Regulation Up (RU), Regulation Down (RD), Spinning Reserve (SP) and Non-Spinning Reserve (NS) decreased from September to October 2003, prices for RU, RD and SP increased on average. In particular, the $3.21/MW increase in RU and the $1.49/MW increase in SP occurred primarily because few resources were available to provide A/S, so low priced bids were removed from the market. During October, many providers of RU and SP requested and were granted waivers from the "Must-Offer" obligation, permitting them to go offline. As a result, those units were not available to provide A/S.

Table 2. A/S Average Supply and Price

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Sep 03	389	429	896	826	$ 13.02	$ 12.16	$ 5.75	$ 5.22
Oct 03	382	404	796	731	$ 16.23	$ 12.73	$ 7.24	$ 3.85

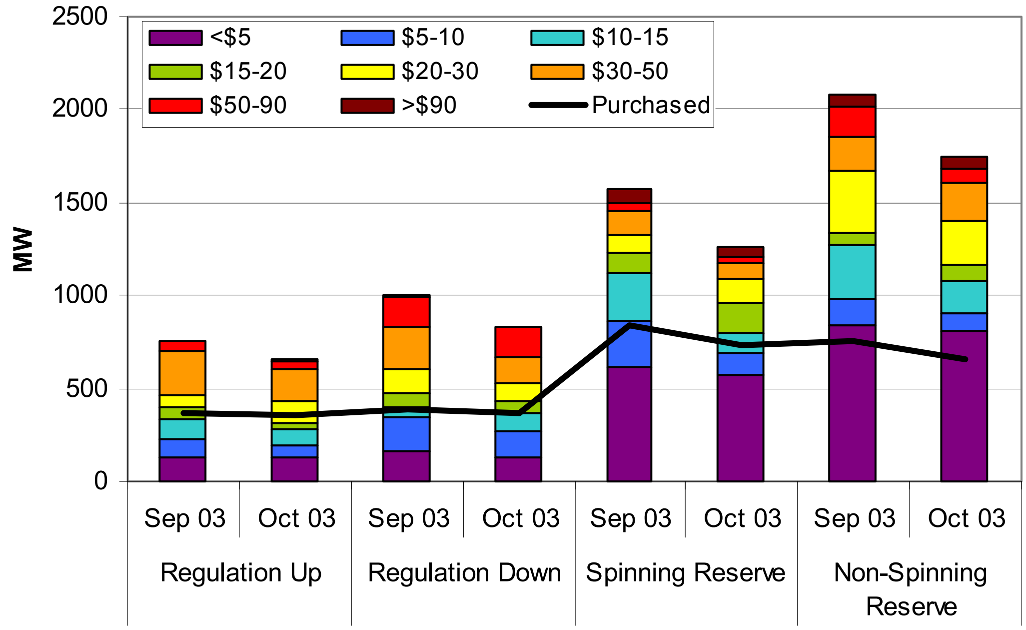
Prices were highest during the two middle weeks of October. Requests for must-offer-waivers peaked during this period. The following chart shows weekly average prices through October, and indicates that October's prices for A/S products were substantially lower than those in the early part of the summer.

Figure 11. Weekly Average Ancillary Service Prices



Market Bids. The average capacity offered to the A/S markets declined between September and October. In the case of Regulation Up (RU) and Spinning Reserve (SP), this decline reduced the volume of low-priced bids, causing increases in average prices.

Figure 12. Monthly Average Bid Composition



Please see the section on Issues under Review for additional discussion of incentives and bid insufficiency in the A/S markets.

IV. Congestion on Transmission Lines between California and Neighboring Regions (Interzonal Congestion)

Path 26, an electricity bottleneck between Northern and Southern California, was congested in the North-to-South direction for 28% of peak hours in October, and incurred congestion costs totaling $3 million.

Wildfires in Southern California impacted forward congestion markets only minimally.

Interzonal congestion costs totaled $4.2 million in October, a significant increase from the $1.8 million reported in September. Of $4.2 million in interzonal congestion costs, nearly $3 million was incurred on the Path 26 branch group in the North-to-South direction. As in recent months, Path 26 continues to be a major bottleneck on the grid. Other congestion costs occurred mostly in the import direction, on COI, Eldorado, Mead, Palo Verde, and Path 15, in the South-to-North direction.

As in earlier months of the year, Path 26 North-to-South congestion tends to occur during the peak hours (between 7:00 a.m. and 10:00 p.m., Mondays through Saturdays). In October, Path 26 was congested in 28 percent of all peak hours in the day-ahead market, with an average congestion price of $10.76/MWh. Congestion prices in the North-to-South direction reached $92/MWh on October 15 between 1:00 and 4:00 p.m., during a derate of the line to 500 MW. Approximately $600,000 in costs was incurred during these three hours. In most days in October, Path 26 was rated at a capacity of 2,500 MW in the North-to-South direction, but on a few days, such as October 5, 15, 16, 17, and 19, the capacity fluctuated between 2,500 MW and 3,000 MW as a result of system conditions in the Vincent area.

The California-Oregon Intertie (COI) and NOB, the two major branch groups that import power from the Northwest region to the ISO control area, also experienced congestion, primarily due to derates. COI and NOB experienced multiple derates throughout October due to scheduled maintenance. NOB was completely out of service from October 7 to October 22 due to scheduled maintenance. From October 22, the importing capacity on NOB was 734 MW, significantly lower than its normal import capacity of about 2,000 MW. Similarly, the import capacity on COI was also derated due to scheduled maintenance. COI was derated to the range of 500 to 600 MW on October 25 and 26, from its usual range of 3500 to 4000 MW, due to scheduled annual tests.

Congestion also occurred on the Eldorado and Palo Verde branch groups, the interties that connect the ISO control area to the southwest region. All such congestion was in the import direction. Eldorado was congested on October 28, from 10:00 p.m. to 12:00 midnight, with congestion prices of $43/MWh; and on October 21, from 12:00 noon to 12:00 midnight, with congestion prices of $32/MWh. Palo Verde was congested on October 14, 22, 24, and 25, with a maximum congestion price of $3.76/MWh.

The recent wildfires in Southern California appear to have impacted the forward interzonal congestion markets only minimally. For example, the Palo Verde line was derated by approximately 1,000 MW for 22 hours on October 27, in the hour-ahead market, due to the wildfire under the Miguel and Imperial Valley line, but no money actually changed hands as a consequence. The following tables show Interzonal congestion frequencies, prices, and costs in October.

Table 3. Interzonal Congestion Frequencies and Prices, October 2003

			Day Ahead			Hour Ahead		
Branch Group	**Direction of Cngs.**	**Peak/Off-Peak Hours**	**No. of Cngs. Hours**	**Pct of Hours Being Cngs.**	**Avg. Cngs. Price ($/MWh)**	**No. of Cngs. Hours**	**Pct of Hours Being Cngs.**	**Avg. Cngs. Price ($/MWh)**
CASCADE	EXPORT	ON-PEAK				16	4%	0.00
COI	IMPORT	OFF-PEAK	9	4%	1.00			
COI	IMPORT	ON-PEAK	100	21%	4.74	101	22%	11.30
ELDORADO	IMPORT	OFF-PEAK	4	2%	37.91			
ELDORADO	IMPORT	ON-PEAK	10	2%	32.62	8	2%	21.33
LUGO-IPP (DC)	IMPORT	ON-PEAK	1	0%	30.00			
LUGO-MONA	IMPORT	ON-PEAK	17	4%	28.32			
LUGO-WEST WING	IMPORT	ON-PEAK				1	0%	30.00
MEAD	IMPORT	ON-PEAK				15	3%	42.54
NOB	IMPORT	ON-PEAK	31	6%	1.69	32	5%	11.37
NOB	EXPORT	OFF-PEAK				2	1%	2.50
NOB	EXPORT	ON-PEAK	4	0%	0.25	6	0%	2.33
PALO VERDE	IMPORT	OFF-PEAK	2	1%	1.50	3	1%	35.63
PALO VERDE	IMPORT	ON-PEAK	28	6%	1.62	17	4%	42.93
PATH 15	S-N	OFF-PEAK	84	35%	1.07	5	2%	17.17
PATH 15	S-N	ON-PEAK	21	4%	0.32	14	3%	26.14
PATH 26	N-S	ON-PEAK	132	28%	10.76	47	10%	23.54
SUMMIT	EXPORT	ON-PEAK	45	9%	0.00	11	2%	5.45

Table 4. Interzonal Congestion Costs, October 2003

Branch Group	**Day-ahead**		**Hour-ahead**		**Total Congestion Cost**		**Total Congestion Cost**		**Total Congestion Cost**
	Import	Export	Import	Export	Export	Import	Day-ahead	Hour-ahead	
COI	$256,724	$0	$102,165	$0	$358,889	$0	$256,724	$102,165	$358,889
ELDORADO	$349,566	$0	$35,862	$0	$385,428	$0	$349,566	$35,862	$385,428
LUGO-IPP (DC)	$11,101	$0	$0	$0	$11,101	$0	$11,101	$0	$11,101
LUGO-MONA	$77,054	$0	$0	$0	$77,054	$0	$77,054	$0	$77,054
MEAD	$0	$0	$105,581	$0	$105,581	$0	$0	$105,581	$105,581
NOB	$38,537	$0	$11,200	$2,491	$49,737	$2,491	$38,537	$13,691	$52,228
PALO VERDE	$93,933	$0	$462	$0	$94,395	$0	$93,933	$462	$94,395
PATH 15	$184,706	$0	$6,111	$0	$190,817	$0	$184,706	$6,111	$190,817
PATH 26	$0	$2,932,993	$0	$25,416	$0	$2,958,409	$2,932,993	$25,416	$2,958,409
SUMMIT	$0	$0	$2	$0	$2	$0	$0	$2	$2
Grand Total	$1,011,620	$2,932,993	$261,383	$27,907	$1,273,003	$2,960,900	$3,944,613	$289,290	$4,233,903

V. Firm Transmission Rights Market (FTR)

FTR scheduling. FTRs can be used to hedge against high congestion prices and also to establish scheduling priority in the day ahead. As shown in the following tables, a high percentage of FTRs was scheduled on certain paths (78% on Eldorado, 91% on LUGO-IPP (DC), 66% on Palo Verde, 98% on Silver Peak in the import direction, and 46% on Path 26 in the South-to-North direction). FTRs on those paths are mainly owned by Southern California Edison Company (SCE1) and municipal utilities.

Table 5. FTR Scheduling Statistics for October, 2003[7]

Direction	Branch Group	MW FTR Auctioned	Avg. MW FTR Scheduled	Max MW FTR Scheduled	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	COI	745	285	510	500	38%
IMP	ELDORADO	510	400	410	410	78%
IMP	IID-SCE	600	431	470	450	72%
IMP	LUGO-IPP (DC) **	370	347	367	235	94%
IMP	LUGO-MONA **	167	93	117	65	55%
IMP	LUGO-WEST WING **	93	28	41	28	30%
IMP	MEAD	516	51	121	50	10%
IMP	NOB	686	21	201	100	3%
IMP	PALO VERDE	627	412	425	400	66%
IMP	SILVER PEAK	10	10	10	10	98%
EXP	LUGO-MARKETPLACE **	247	3	3	3	1%
EXP	NOB	664	6	74	74	1%
S-N	PATH 26	1,425	649	1,306	560	46%

FTR Revenue per Megawatt. The following table summarizes the FTR revenue collected through October. FTR revenue per MW increased on most branch groups in October due to the presence of congestion. The FTR revenues on COI (import), Eldorado (import), and Path 26 (North-to-South) were $352/MW, $516/MWh, and $1433/MW respectively in October, higher than those reported in September. The following table shows FTR revenues in September.

7 Only those paths on which 1% or more of FTRs were attached are listed.

** The FTRs on these paths were awarded to municipal utilities that converted their lines under the ISO operation and thus were not released in the primary auction.

Table 6. FTR Revenue Per MW ($/MW), October 2003

Direction	Branch Group	Net $/MW FTR Rev Apr	May	Jun	Jul	Aug	Sep	Oct	Cum. Net $/MW FTRREV – Imp	Pro Rated NET $/MW FTRREV - Imp	FTR Auction Price
IMPORT	BLYTHE	69	0	231	1,422	376	0	0	2,097	3,596	5,460
IMPORT	COI	723	536	299	138	440	192	352	2,680	4,595	59,484
IMPORT	ELDORADO	0	0	1	0	0	268	516	785	1,345	33,888
IMPORT	LUGO-IPP (DC)**	272	0	0	5,151	8	0	30	5,461	9,361	0
IMPORT	LUGO-MONA**	0	715	7	0	15	310	461	1,509	2,586	0
IMPORT	LUGO-WEST WING**	3	0	0	0	0	9	0	12	21	0
IMPORT	MEAD	166	0	14	150	85	137	158	709	1,215	46,920
IMPORT	NOB	249	203	68	96	118	42	68	843	1,446	73,470
IMPORT	PALO VERDE	233	15	5	251	355	413	49	1,322	2,266	88,167
S-N	PATH 26	0	0	5	0	0	0	0	5	8	1,470
IMPORT	SUMMIT	108	0	0	0	0	0	0	108	186	2,600
EXPORT	IID-SDGE	0	480	0	0	5,651	0	0	6,131	10,511	364
EXPORT	NOB	0	0	0	0	0	0	3	3	6	5,085
N-S	PATH 15	0	5	0	0	0	0	0	5	9	0
N-S	PATH 26	1,147	1,500	224	780	572	113	1,433	5,770	9,891	34,408
EXPORT	SILVER PEAK	0	0	720	0	0	0	0	720	1,234	100

*Pro-rate 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.
** FTRs on these paths were awarded to municipal utilities that converted their lines to the ISO, and there were not released in the primary auction.

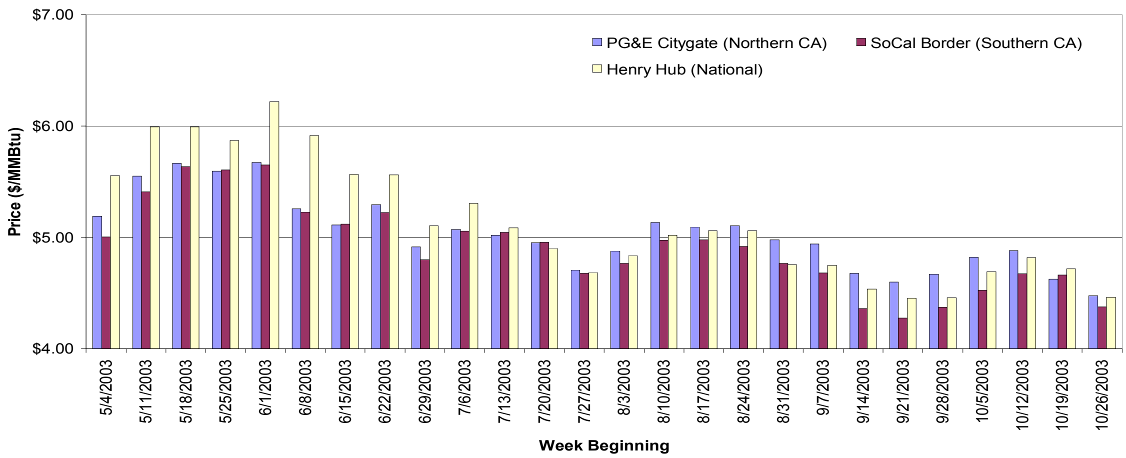
FTR Concentration There were no trades in the secondary FTR market in October. The FTR owner concentration table reported in April remains intact.

VI. Natural Gas Prices

Natural gas prices continued their downward trend for the year in October, with occasional increases, as pumping into storage raised prices mid-month. October prices averaged $4.47/MMBtu at Henry Hub, a national trading location. Regional prices averaged $4.36/MMBtu at Malin, and California border prices were $4.75 per million British thermal units (MMBtu) at PG&E Citygate, and $4.52/MMBtu at Southern California Border. The weekly pattern of prices showed decreases from the end of September to the first week of October, ranging between $4.22 and $4.61/MMBtu, on average. Prices increased as more gas was placed into storage in the second and third weeks of October, during which average prices ranged between $4.52 and $4.88/MMBtu. Prices weakened between October 17 and 20, after which Henry Hub and California prices returned to $4.60/MMBtu levels. Malin prices, however, averaged $4.26/MMBtu during this period. Moderate temperatures prevailed throughout the West in the final few days of October, when prices ranged between $4.15 and $4.44/MMBtu on average, although colder weather in the Pacific Northwest and in Northern California drove PG&E Citygate prices above Henry Hub prices.

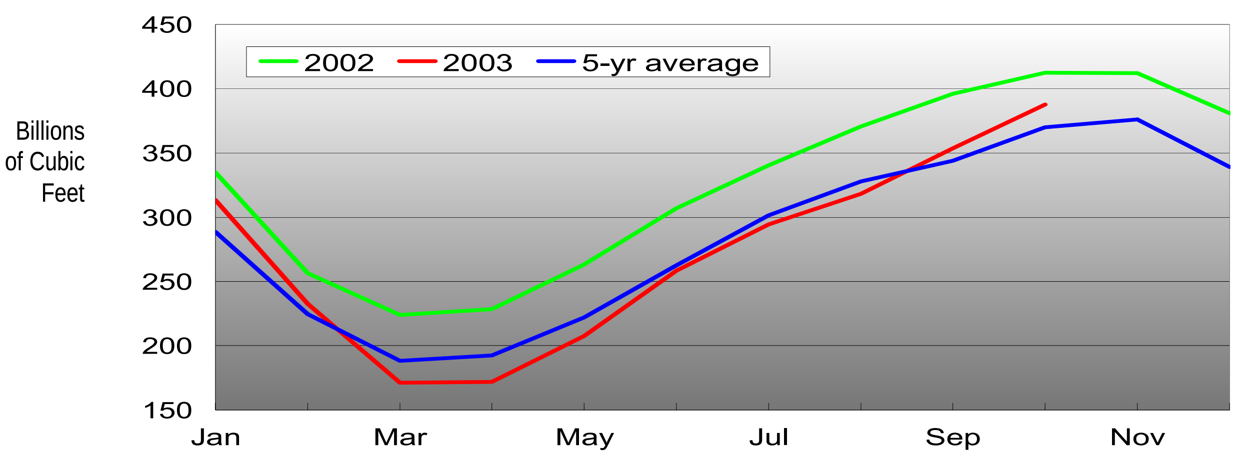
October Bid-week prices, or the forecast of prices for November monthly contracts, were $4.28, $4.25, and $4.54 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 2%, 1%, and 4%, from September bid week prices. The following chart shows weekly average gas prices through October.

Figure 13. Regional Gas Prices through October



Regional storage levels increased in October 2003 relative to the same month in recent years. The following chart shows monthly natural gas storage levels through 2003.

Figure 14. Western Regional Gas Storage Levels, 2001 through 2003

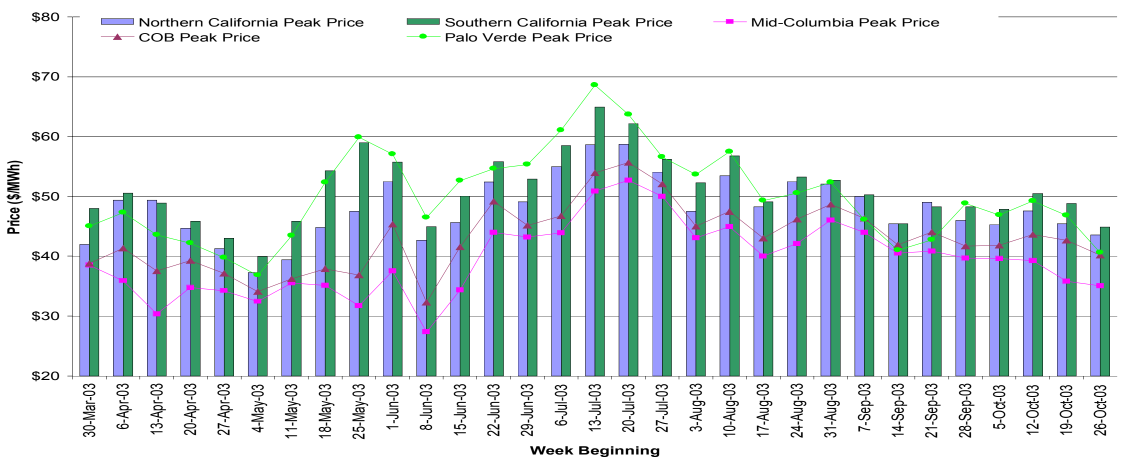


VII. Regional Day-Ahead Bilateral Prices

Regional day-ahead electricity prices averaged $42.93/MWh at the California-Oregon Border, $38.39/MWh at Mid-Columbia, $46.71/MWh at Palo Verde, $48.48/MWh in Northern California, and $50.00/MWh in Southern California on the weekdays in October. During the first week of October, prices decreased from the end of September to average between $39.75 and $53.25/MWh. In particular, Palo Verde hub prices decreased from over $60/MWh at the end of

September to $48.00/MWh on October 5. Relatively high gas prices during the second, third and fourth weeks of October drove up electricity prices, with Southern California and Palo Verde prices averaging around $50/MWh and Northwest and Northern California prices averaging $44/MWh. Day-ahead electricity prices moderated during the last week of October in step with gas prices; by month's end, electricity prices ranged between $39.00 and $43.25/MWh. The following chart shows weekly average day-ahead prices for bilateral contracts reported in trade publications through October.

Figure 15. Regional Bilateral Day-Ahead Prices



VIII. Issue under Review

The combination of Must-Offer Waivers and RMR Condition 2 appear to have created incentives that adversely impact bid volume offered into A/S markets.

Incentive Issues in Ancillary Services Markets. One of the causes of the decline in bid sufficiency in A/S markets may be the perverse incentive to withhold capacity created by RMR Condition 2 Contracts and the Must-Offer Waiver process. This situation is exacerbated whenever generation units do not have bilateral contracts to sell energy, and must depend solely on imbalance energy and A/S capacity sales to be online each day.

Reliability Must-Run (RMR) Condition 2 contracts, which effectively provide the ISO with a lease on an entire unit to operate it as needed for reliability purposes, preclude such units from offering to the A/S markets. Between 2002 and 2003, a substantial portion of capacity exited the A/S markets, as unit owners elected to sign RMR Condition 2 contracts. This implies that the benefits of RMR Condition 2 contracts to generation owners may outweigh the market opportunities to sell real-time balancing energy and ancillary service capacity from these units. If additional generators elect to move generators to Condition 2 contracts, the total capacity available to the market may further diminish.

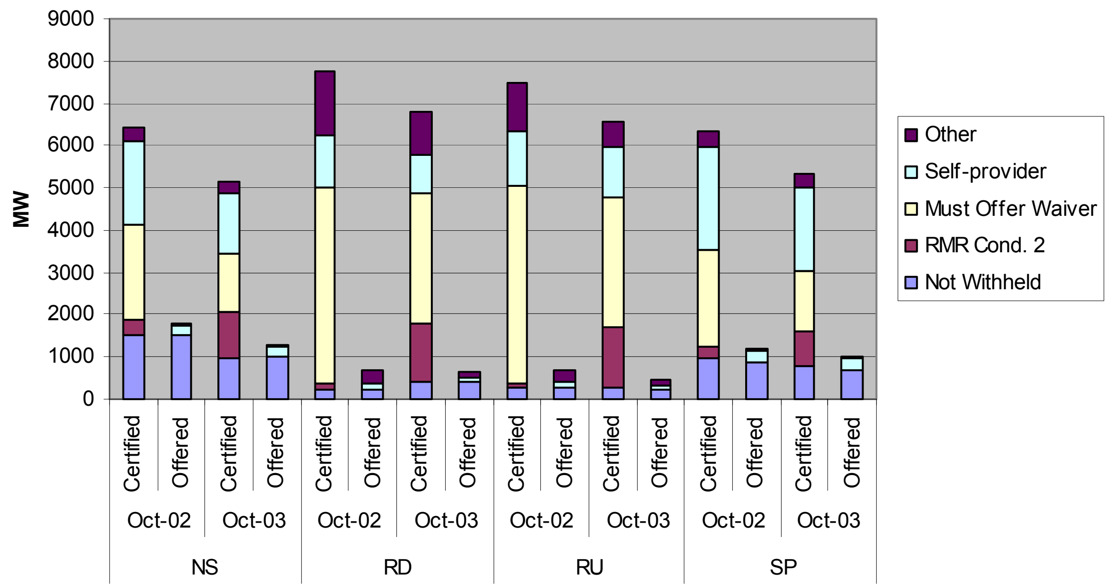
Generating units that are offline are generally not eligible to provide A/S (except for ten-minute quick start units in certain circumstances). Similarly, generating units that have been granted waivers to the Must-Offer Obligation are not eligible to provide A/S. Both of these conditions are voluntary, and generally would be selected by a unit owner for economic reasons. This suggests that the A/S and imbalance energy markets may not provide sufficient revenues to certified generators that need not be on and running to meet contracted demand. These two categories together account for 2,000 MW or more of capacity.

In many hours of October 2003, the capacity offered to the hour-ahead (HA) SP market was not adequate to fulfill the hour-ahead requirement for SP. On October 16, 2003, the HA SP market was short by as much as 301 MW – nearly 40% of the average hourly requirement -- for eight hours. On October 27, 2003, the HA SP market was short of capacity (up to 132 MW) for six hours. These deficits were covered by capacity from RMR contracts.

For example, in October 2003, approximately 5,310 MW of certified Spinning Reserve capacity could have been available to the system in an average hour. Of that capacity, on average only 1,265 MW (12.1%) was offered to the markets. In October 2003, 825 MW (7.9%) of certified SP capacity was unavailable to the market under an RMR Condition 2 contract, compared to 275 MW (2.6%) in October 2002.

The following chart shows A/S certified capacity by status for each service in October 2002 and 2003. Please note that capacity that is actually generating, capacity that is offline, and capacity that does not participate in ISO markets, are not reflected in this chart.

Figure 16. A/S Certified Capacity by Status[8]



Most of this withheld capacity consists of units whose applications for waivers from the Must-Offer Obligation were denied. When a unit is denied a waiver application, and then offers A/S capacity and is awarded, it is no longer entitled to either the minimum load cost compensation (MLCC) or uninstructed energy (UE) payments. The rescinding of these payments appears to create a disincentive for generators to offer capacity into the A/S markets.

The nominal availability (based on certified ramp rate and name plate rating) of resources self-providing ancillary services typically is much greater than the capacity offered into each market. A large portion of self-provided A/S capacity is from hydroelectric resources, and additional capacity beyond that which was offered into market may not be available due to inadequate water storage behind dams or other operational reasons. Furthermore, self-providing generating units must allocate firm capacity to each service rather than offering all available capacity to each market.

Given current conditions, only a few hundred megawatts of the 4,000 or so available megawatts certified but not offering capacity into the market would be needed to restore adequate volume to the market.

[8] Units that are certified to offer multiple services may offer available capacity bids for each of those services. Each pair of bars in the chart compares certified capacity for a particular service type (NS, RD, RU, SP) to the corresponding capacity of that service type actually offered. New generation and changes in actual load may affect annual trends in certified available capacity, for example. The "Other" category represents capacity that is online and not known to be unable to bid A/S.