CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: March 18, 2004

Re: **Market Analysis Report for February 2004**

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

Executive Summary

The California wholesale electric markets continued to perform well in February serving average customer demand that was 4.5 percent higher than February of last year. The increase in demand was a result of the combination of the improving economy as well as the comparison with demand resulting from very mild weather in the first half of 2003. The real-time market was stable in February with only a few price spikes occurring during the early evening load ramp periods. The average incremental imbalance energy price decreased to $61.81/MWh from January's $70.17/MWh. Our estimate of the mark-up above cost of production, measuring the competitiveness of the real-time market was even lower than January's levels. We estimate the mark-up to be between 4 and 10 percent. This indicates that the imbalance energy market continues to be competitive.

Natural gas prices declined steadily through February. Prices averaged around $5/MMbtu. They were substantially lower than those in January as moderate temperatures throughout California reduced demand for gas heating. Day-ahead bilateral electricity prices declined throughout the month from $50/MWh to $40/MWh as a result of the lower natural gas prices. Prices at the end of February were at the lowest levels since Nov 2003.

The major problem once again affecting the real-time imbalance energy market was managing congestion in real-time (intra-zonal (within zone) congestion). The San Onofre Nuclear Generating Station (SONGS) Unit 2 began planned refueling on February 9 and is not expected to return to service until March 25. The loss of its generation south of Los Angeles has resulted in greater flows over the South West Power Link (SWPL, a transmission line between Arizona and San Diego), exacerbating congestion at the Miguel substation. This resulted in significantly higher out-of-sequence (OOS) costs to resolve congestion in real-time. OOS costs totaled approximately $8.0 million in February, an increase from $5 million in January.

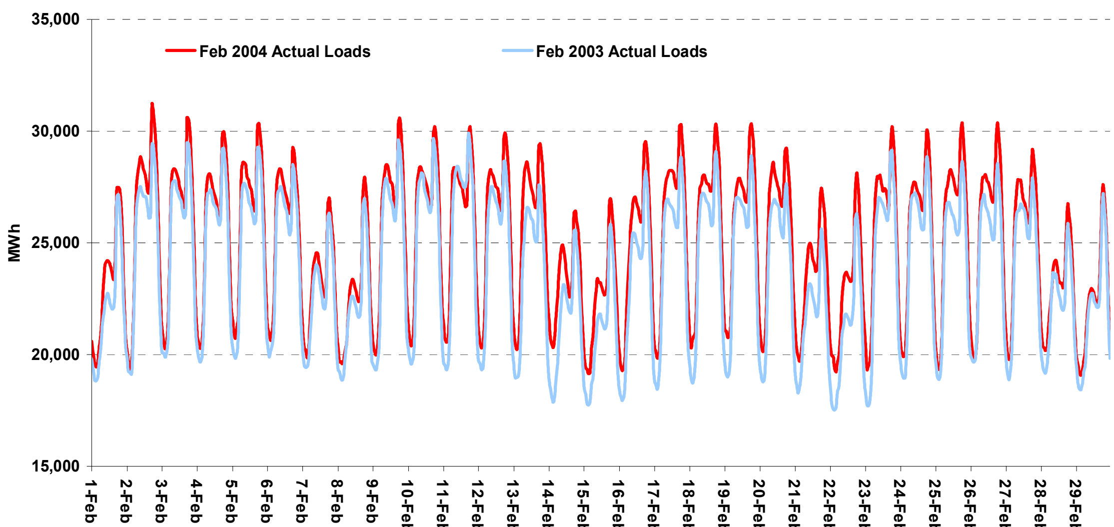
Day ahead inter-zonal (between zone) congestion costs were $1.1 million in February, a slight decrease from the $1.4 million in January. Nearly half of the cost in February was incurred on Palo Verde as abundant generation in the southwest was scheduled into Southern California.

Average ancillary service prices decreased 3.5% for all services despite the 4.5 percent increase in demand from January to February 2004. The frequency of bid insufficiency decreased by 59 percent during the same period. The improvement in the ancillary services markets was largely due to the "flattening" of the daily load profile that reduced the demand for ancillary services during peak load hours.

I. Factors Affecting Demand and Supply Conditions

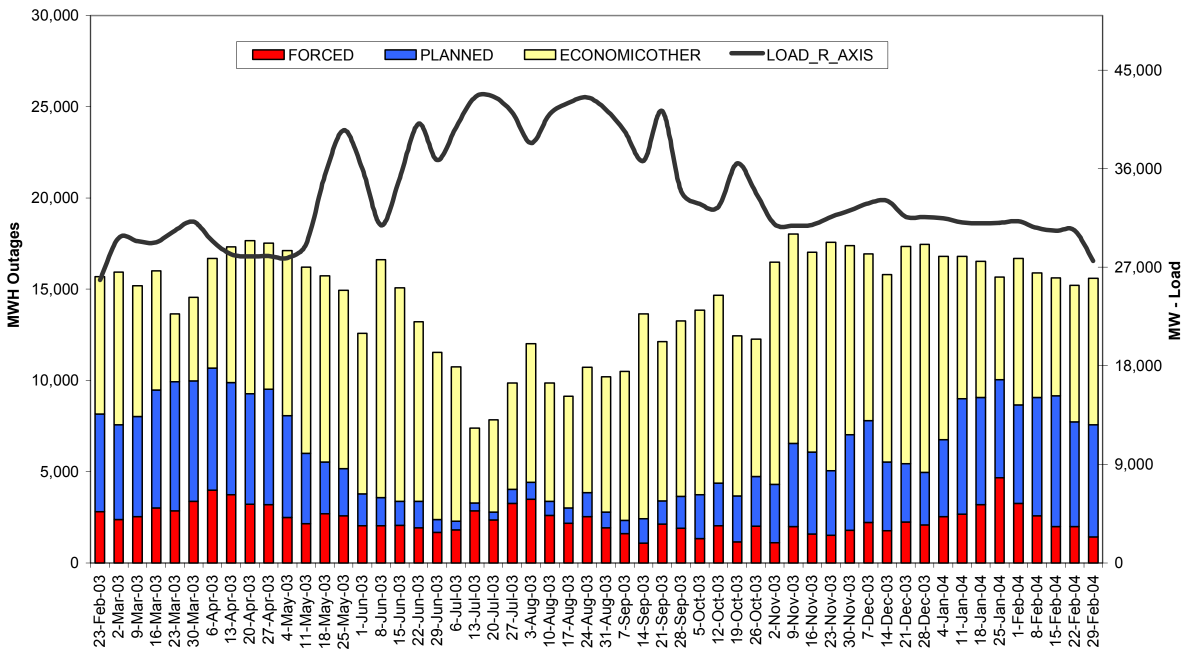
Loads. The February peak load was 29,852 MW and the average load was 23,820 MW. Both were 4.5 percent greater than those in February 2003, when weather in California was unseasonably mild. Although weather fluctuations can have significant impacts on average monthly and peak load statistics, the ISO control area has experienced consistently higher average loads compared to the previous year since July 2003. It is necessary to weather normalize loads in order to get a more accurate indicator of the underlying economic load growth has occurred over the past year. A review to see if there is load underscheduling shows hourly average schedules in February 2004 averaged within three percent of load, with scheduled energy less than load in the early morning and evening ramps, and scheduled energy exceeding of load in all other hours. Figure 1 shows hourly average loads for February 2003 and 2004.

Figure 1. Hourly Actual Loads, Feb-04 v. Feb-03



Outages. Two baseload nuclear units were out of service during February. The San Onofre Nuclear Generating Station (SONGS) Unit 2 began planned refueling February 9, and is expected to return on March 25. Palo Verde Unit 1 experienced an unplanned one-day outage on February 4 due to a coolant pump lead. Palo Verde Unit 2 was forced out on February 19 due to a small tube leak in one of the unit's two steam generators and did not return to service until early March. Palo Verde Unit 3 was also forced out in early March. The units continue to be held at minimum load pursuant to the Must-Offer Obligation.[1] A number of other units continue to be out of service for planned maintenance during the shoulder season. Figure 2 shows weekly average outages through February.

Figure 2. Weekly Average Outages through Feb-04

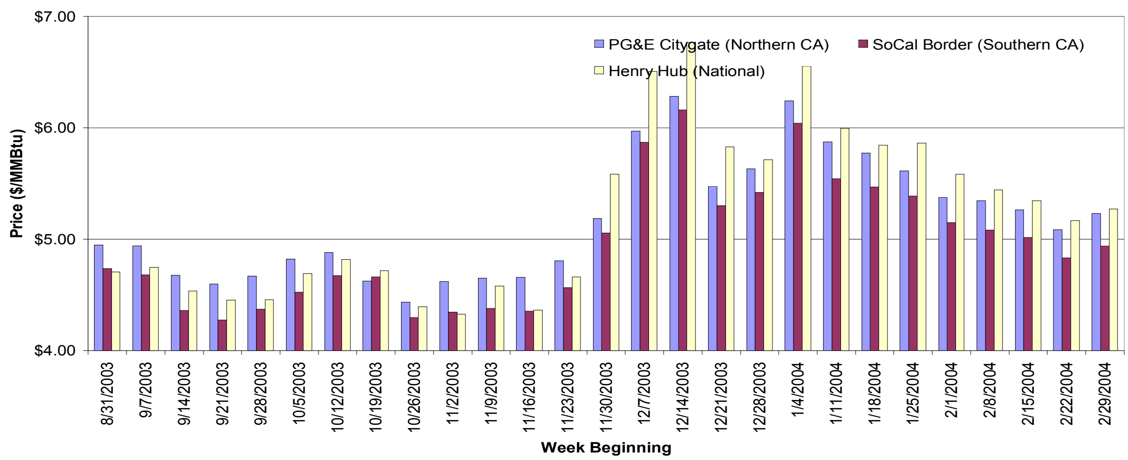


Natural Gas Prices. Natural gas prices declined steadily through February. Average prices were $5/ MMBtu, substantially lower than those in January, as moderate temperatures throughout California reduced heating demand. The February average prices were close to average prices a year ago in 2003, when natural gas prices averaged $5.90/MMBtu. The highest prices in February occurred during the first and second weeks of the month when cooler temperatures increased heating demand. Prices remained moderate however, with average California prices ranging between $5.02 and $5.35/MMBtu during the first week and $5.01 and $5.38 during the second week. For the remainder of February, prices continued a small but steady descent with an average price for that period of $4.92/MMBtu at California delivery points.

Average daily gas prices for February were $5.29/MMBtu at Henry Hub, $4.92/MMBtu at Malin, $5.28/MMBtu at PG&E Citygate, and $5.03/MMBtu at Southern California Border Average. Average bid week prices for March were $4.75, $4.62, and $4.99 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 10%, 12%, and 10% from February bid week prices. Figure 3 shows weekly average gas prices at regional delivery points through February.

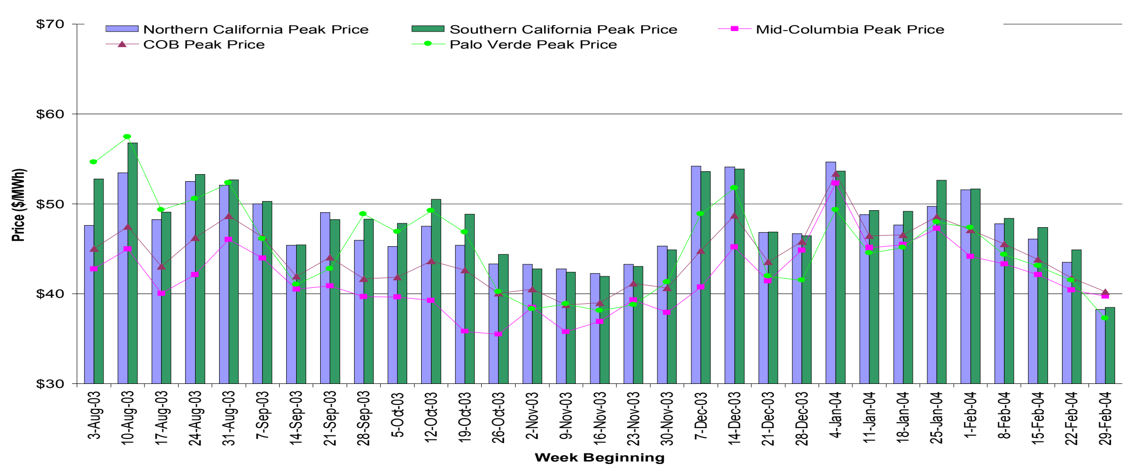
[1] The "Must-Offer" Obligation was directed by the Federal Energy Regulatory Commission in an Order issued June 19, 2001, and was upheld in subsequent Orders.

Figure 3. Weekly Average Natural Gas Prices through Feb-04



Regional Day–Ahead Bilateral Electricity Prices. February electricity prices followed the decreasing trend in natural gas prices, with overall average prices lower than those in January. February's peak prices occurred on February 4, when Palo Verde Unit 1 (1,352 MW) experienced an unplanned outage due to a coolant pump leak. Prices for Southern California peaked at $55.25/MWh for deliveries on February 5 with prices quickly returning to the $49/MWh level. On February 16, higher natural gas prices and the California-Oregon Inter-tie being curtailed to 3,000 MW caused electricity prices to increase to $52.00/MWh in Southern California. For the remainder of the month, prices averaged $47/MWh. Average February peak weekday regional day-ahead electricity prices were $44.80/MWh at the California-Oregon Border, $42.49/MWh at Mid-Columbia, $44.58/MWh at Palo Verde, $47.66/MWh in Northern California, and $48.85/MWh in Southern California Figure 4 shows weekly average day-ahead bilateral electricity contract prices through February.

Figure 4. Day-Ahead Bilateral Electricity Prices through Feb-04



II. ISO Real-Time Market Performance

The real-time market remained stable throughout February with the exception of a significant increase in intra-zonal congestion costs. The incremental price, the price the CAISO pays to generators to increase energy output when scheduled energy is less than load, averaged \$61.81/MWh in February compared to \$70.17/MWh in January. Meanwhile, the decremental price, the price generators pay the CAISO to reduce their output and resultant production costs when schedules exceed actual load, averaged \$19.79/MWh in February compared to \$20.53/MWh in January. A more significant change is the ratio of decremental to incremental energy. The ratio fell to approximately 2 to 1 in February, compared to 4 to 1 in recent months. This indicates an improvement in forecasting and scheduling accuracy. However, the incremental activity was partly to offset redispatches to manage intrazonal congestion that has been exacerbated recently by the San Onofre outage. Intrazonal redispatch premium costs in February totaled \$8 million.

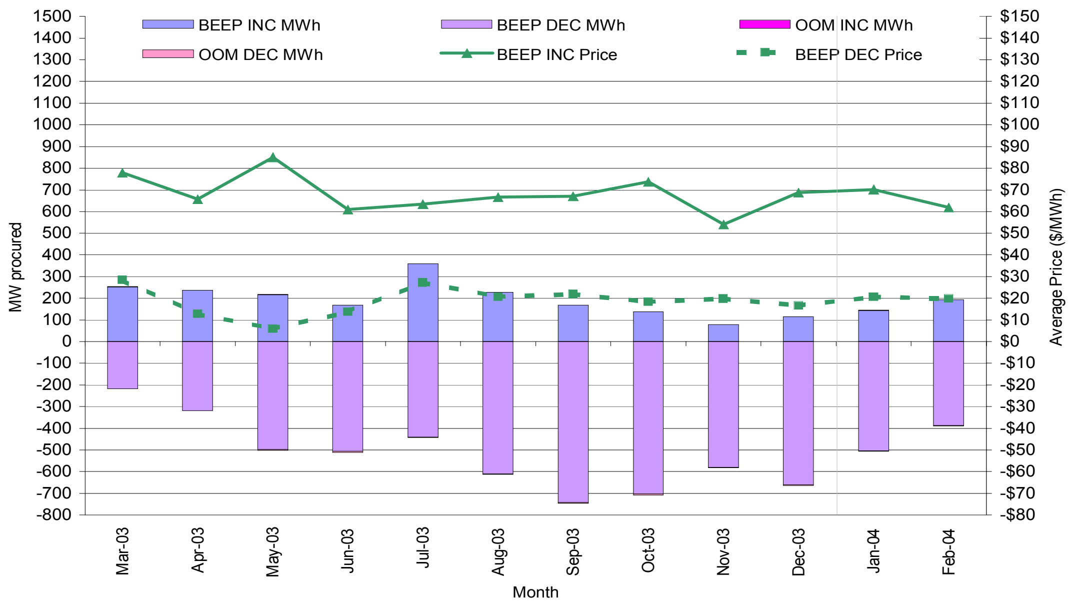
The CAISO real-time incremental balancing market has continued to experience high prices during the evening ramp period between 5:00 and 7:00 p.m., albeit less so than in recent months. The Department of Market Analysis expects early evening price spikes to give way to late-evening and early-morning price spikes as daylight lasts later into the evening hours in the coming months. In the spring of 2003, prices were high between 9:00 and 11:00 p.m.. Long-term contract provisions in several contracts resulted in energy being delivered in rigid 16-hour blocks whose end time was out of phase with the evening decrease in load. The CAISO corrected for the imbalance through the real-time market. A similar (but reverse) problem occurred between 6:00 and 7:00 a.m. as some of the long-term contracted energy delivery began before the morning increase load.

Table 1 below shows average real-time prices and total energy dispatched in the real-time market, average system loads, and percent underscheduling, for peak, off-peak, and all hours in February. Figure 5 shows monthly price and volume trends for the 12 months ending in February.

Table 1. Average Real-Time Prices, Total Energy, System Loads, and Percent Underscheduling, in Feb-04

	Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	
Peak	$ 63.33	$ 19.70	26,688 MW
	105 GWh	205 GWh	-0.7%
Off-Peak	$ 56.31	$ 20.10	21,263 MW
	29 GWh	65 GWh	-0.4%
All Hours	$ 61.81	$ 19.79	24,880 MW
	134 GWh	271 GWh	-0.6%

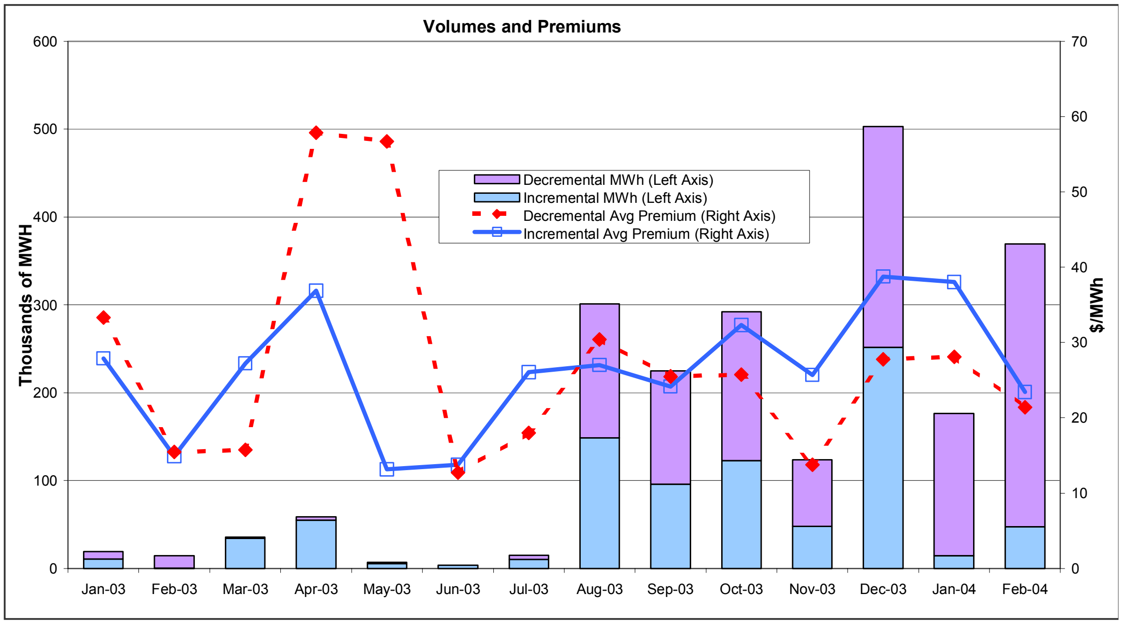
Figure 5. Monthly Real-time Price and Volume, Mar 2003-Feb 2004



Real-time Intra-zonal (within zone) Congestion. While congestion in January was subdued, February experienced increased decremental intra-zonal congestion, primarily caused by the San Onofre refueling outage. The loss of this generation has resulted in greater flows over the South West Power Link (SWPL), a transmission line between Arizona and San Diego, exacerbating real-time congestion at the Miguel transformer bank. Most incremental congestion was due to the Southern California Import Transmission Nomogram (SCIT), a technical constraint on energy imports into SP15 from the southwest. February out-of-sequence (OOS) dispatches resulted in a redispatch premium (the additional cost of calling units out of sequence at bids above the market price) of approximately $8 million. Total OOS dispatch volume was 370 GWh (INC plus DEC) and the average redispatch premium was $22/MWh. Figure 5 presents twelve months of OOS prices and volumes through February.[2]

[2] OOS net cost or redispatch premium is calculated as total redispatch cost minus unconstrained dispatch cost, which is the equivalent dispatch cost at zonal MCP. The premium includes the increased cost of redispatch and any potential mark-up above marginal cost.

Figure 2. Monthly Prices and Volumes to Relieve Real-time Congestion Jan –03 through Feb-04

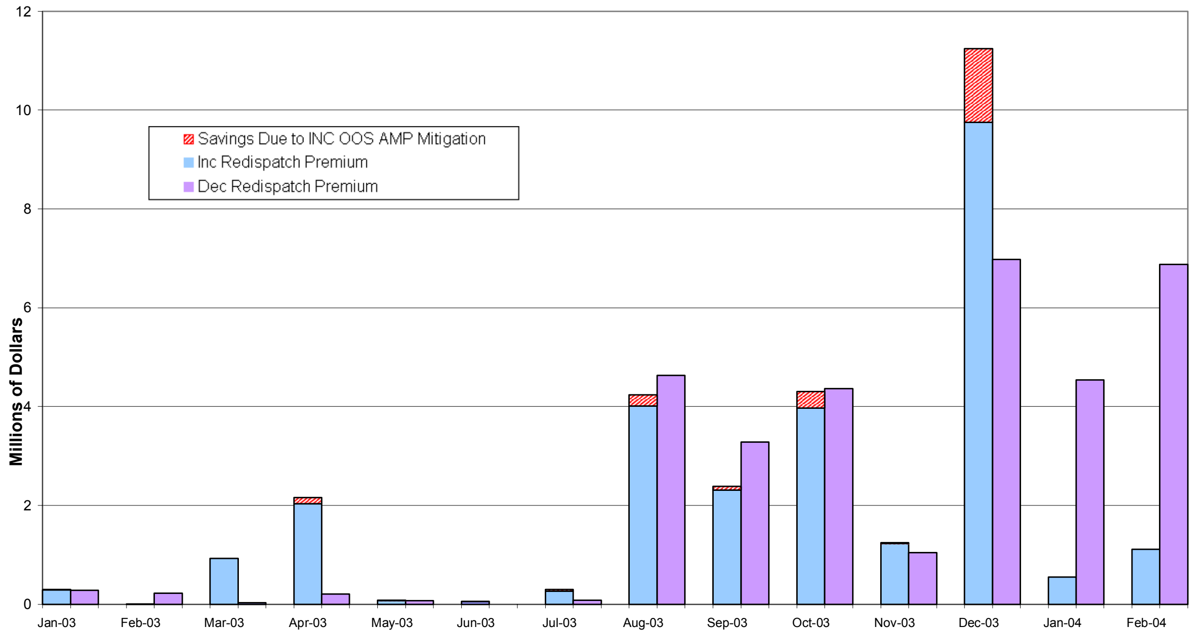


CAISO operators called a total of 47,242 MWh of incremental energy out-of-sequence (OOS) to manage intrazonal congestion during February. The average price paid for OOS calls was $53.95/MWh. The re-dispatch premium in excess of the market clearing price (MCP) averaged $23/MWh, or a total of approximately $1.1 million. Many such incidents were due to mitigation pursuant to the SCIT nomogram that limits the amount of energy that can be simultaneously imported into Southern California. Others were due to transmission line and substation maintenance.

A total of 322 GWh of decremental energy was dispatched out of sequence in February. Decremental OOS energy is settled pursuant to the provisions of the FERC-approved Amendment 50 mitigation measures. Redispatch premium costs in excess of the market clearing price totaled approximately $6.9 million. As in previous months, nearly all of the decremental activity was due to intra-zonal congestion in the San Diego region caused by generation schedules from the new generation units located in northern Mexico combined with congestion on SWPL. The San Onofre refueling outage exacerbated decremental congestion due to increased flows on SWPL.

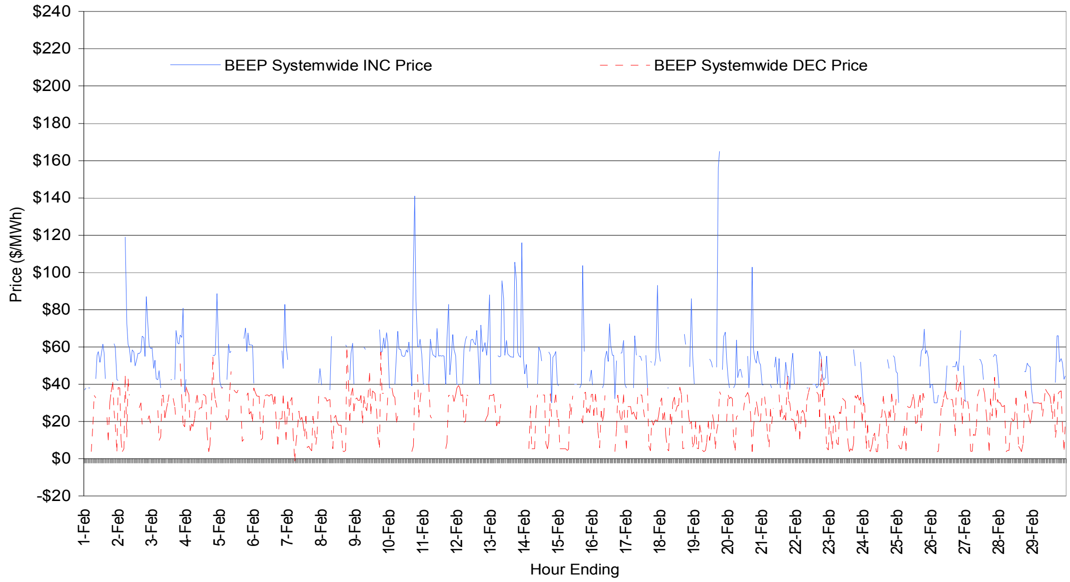
Automatic Mitigation Procedures' local market power mitigation of incremental dispatches (AMP LMPM) resulted in savings of $1,694, or less than 0.2 percent, of total redispatch costs in February. All incremental OOS dispatches are subject to AMP. Figure 6 shows the total redispatch costs for both decremental and incremental intrazonal congestion as well as the savings due to AMP LMPM mitigation of incremental OOS dispatches.

Figure 3. Redispatch Cost Premiums and Savings from Local Market Power Mitigation Jan-03 through Feb-04
Total Intrazonal Redispatch Costs $8 Million in February ($5 Million in January)



Few Price Spikes in February. February saw fewer spikes than recent months, none of which coincided with awarded bids' failures of the Conduct Test. The AMP mitigation measures continued to be a non-factor as no unit that set the price bid in a manner that might have failed the Conduct Test had the hour-ahead predicted price exceeded $91.87/MWh. The following chart shows hourly system-wide average prices in the ISO market in February.

Figure 4. Hourly Systemwide Average Prices in Feb-04



A review of the price spikes show that the primary reason for price spikes in February was the result of significant energy imbalances during the morning and evening load ramps. On February 10, a high imbalance energy demand resulted in prices reaching $140/MWh. Approximately 1,700 MWh were dispatched during this 70-minute spike. The price-to-cost markup was less than $10/MWh, or 7.6 percent above cost, due to the dispatch of a high-cost unit. During this hour, the CAISO experienced a reserve deficiency necessitating that energy bids from ancillary services be skipped per CAISO Operating Procedure M-430.

On February 13,the ISO was decrementing resources, and a thermal unit in Southern California set the system-wide decremental energy price at -$10/MWh between 4:50 and 5:00 a.m. The price-setting unit was the lowest-priced bid available to be dispatched. No decremental energy was called out of market. In the evening, between 5:40 and 6:40 p.m., the real-time incremental price varied between $100 and $110.86/MWh, again due to a reserve deficiency. As a result, the CAISO skipped bids from ancillary services to conserve operating reserves. Between 10:00 and 10:30 p.m., the unit that set the price on February 10, again set the price of $140/MWh. In each of these February 13 cases, the price-to-cost markup ranged between 60 and 70 percent above estimated cost. The cumulative market impact for the day was approximately $99,000.

On February 19, one of the highest-cost thermal units within the CAISO Control Area was dispatched during a zonal price split due to congestion between Northern and Southern California. This unit set the SP15 incremental price of $150 to $170/MWh between 5:30 and 6:50 p.m. The unit's reference level and marginal cost were both approximately $140/MWh. In these hours, this unit offered the highest-priced bids in the market; however, no incremental energy called out of market. Due to this unit's high heat rate, the estimated markup was low. We estimate the market impact of this incident is estimated to be approximately $150,000.

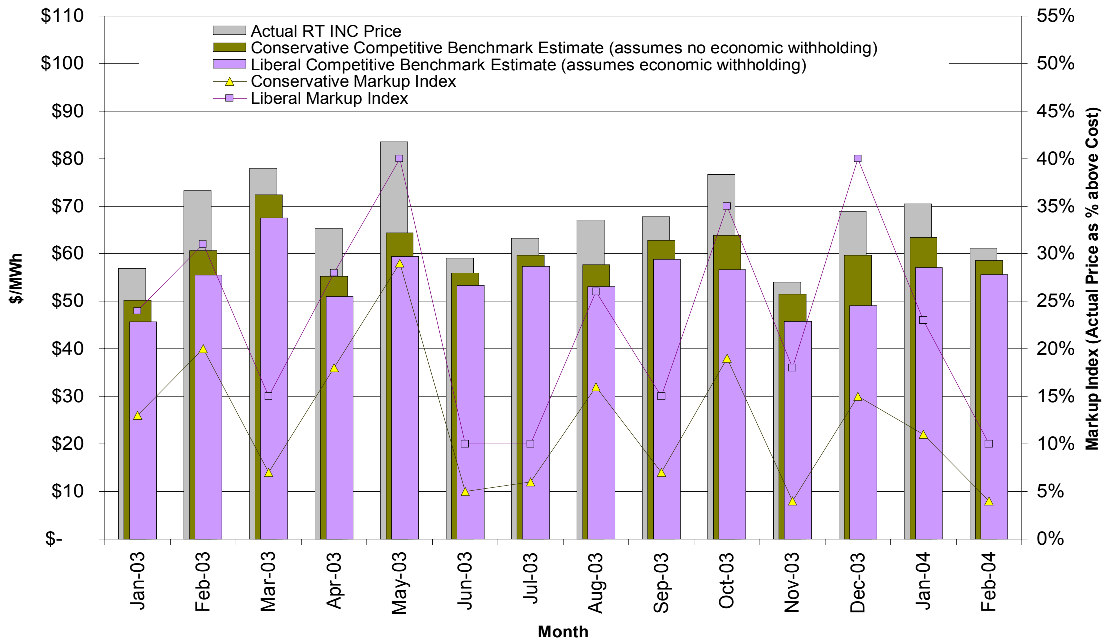
On February 20, the SP15 price was set at $110.86/MWh between 5:20 and 6:00 p.m., again due to import congestion into Southern California. During this time, 1,088 MWh was procured zonally at a market impact of approximately $65,000. The price-setting unit has a gas-adjusted reference level of $117.47/MWh.[3]

Market Competitiveness. The real-time price-to-cost markup is an indicator of the competitiveness of the real-time market. We calculate it by comparing the actual incremental market-clearing price to a competitive benchmark price. As discussed in the Market Analysis Report dated February 19, 2004, the Department of Market Analysis now reports two temporary[4] indices of price-to-cost markup to present a range of the competitiveness of the real-time market. One index assumes no economic withholding; that is, we assume high-priced bids reflect high costs. This produces a higher estimate of the competitive price and results in a conservative (lower) estimate of potential markup. The other index accounts for economic withholding and we substitute estimated marginal cost based bids for high priced bids. This produces a lower estimate of the competitive price and a higher estimate of potential markup.

The price-to-cost markup in real-time incremental balancing energy was very low in February, ranging between 4 and 10 percent for the two indices. This indicates that the real-time market was very competitive in February. In comparison, markup in January was also low, ranging between 11 and 23 percent, again showing competitive market conditions in the real-time market. Figure 8 shows the two volume-weighted average estimates of competitive price vs. the actual volume-weighted average market-clearing prices for the 14 months ending in February.[5]

[3] Because this unit's cost structure is not currently visible to the CAISO, the Department of Market Analysis is not able to estimate a markup for this price spike.
[4] These indices, calculated based upon real-time incremental prices only, determine a range of actual markup in the real-time incremental balancing energy market. They do not reflect prices of forward-contracted bilateral energy, which comprise the bulk of short-term energy costs but are not visible to the ISO. As real-time market volume was less than 1 percent of load-serving energy in February, care must be taken in drawing conclusions from the real-time markup index to the market as a whole.
[5] The DMA will be calculating a net revenue index to track whether market prices are yielding sufficient revenues to attract new generation. This index will be available in next month's report.

Figure 5. Range of Price-to-Cost Markups in Real-Time Energy through Feb-04



III. Ancillary Services (A/S) Reserve Markets

Market Prices. Market prices decreased 3.5% in the ancillary services markets from January to February 2004. Overall demand increased 4.4% in February while overall supply decreased by 5.5%. The majority of the decrease in prices were in the regulation down (RD) markets while the increase in demand was mostly in the regulation up (RU), spinning reserve (SP) and non-spinning reserve (NS) markets. Table 2 shows the average ancillary service requirements for each service and the weighted average price for January and February.

Table 2. Average Ancillary Service Requirements and Prices

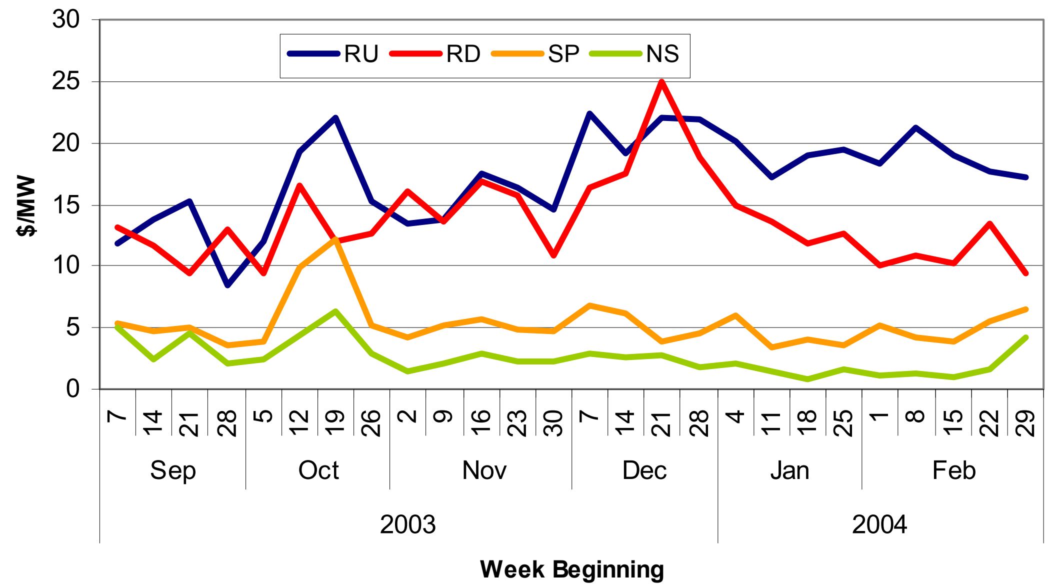
	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Jan 04	363	402	708	676	$ 18.94	$ 13.57	$ 4.29	$ 1.54
Feb 04	391	406	731	710	$ 19.09	$ 11.13	$ 4.82	$ 1.39

A series of unusual events in the hour-ahead RU market contributed to the increase in demand for RU. In several cases, resources that were awarded RU in the day-ahead market were subsequently called for RMR energy. These resources were then unable to provide the awarded RU capacity, so procurement in the HA market was increased. In the absence of this type of event the price of RU would have declined on average. We estimate the re-procurement cost of these events was $333,000.

Prices in the SP markets were 12 percent greater in February than in January. Increased demand under very similar supply conditions stimulated this increase. The NS markets were dominated by self-provision and several resources offering NS at very low prices. In many cases, the day-ahead

NS market cleared below $1/MW. Prices in both SP and NS increased toward the end of the month coincident with a cluster of bid insufficiency events. Figure 9 shows weekly weighted average prices for A/S through February.

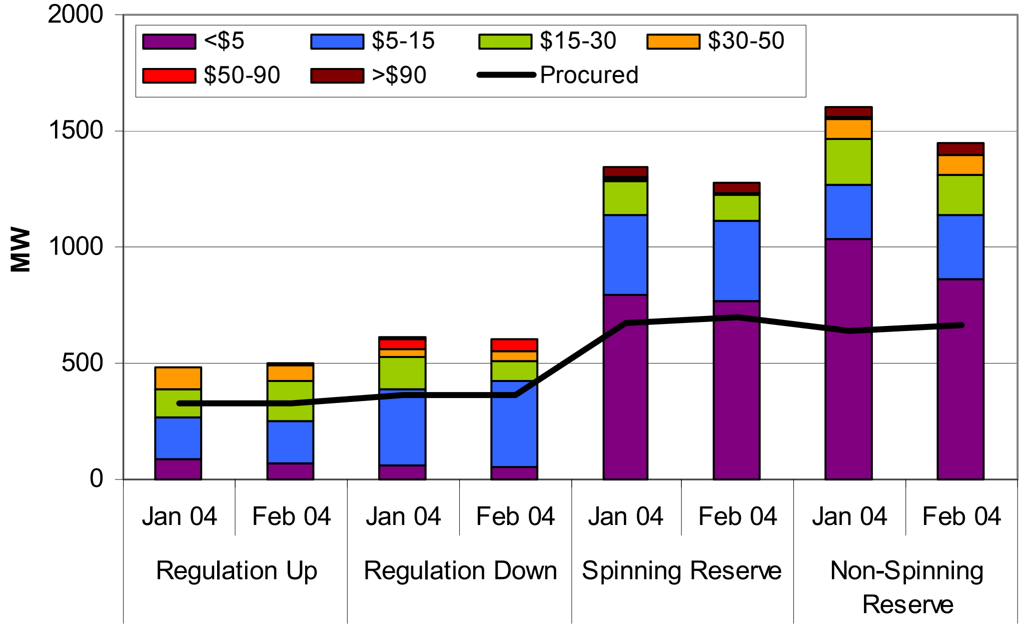
Figure 6. Weekly Weighted Average A/S Prices through Feb-04



Ancillary Service Market Supply. Market supply was characterized by a decline in the frequency of bid insufficiency. Supply declined with increasing demand. The decline in bid insufficiency counteracted the usual upward pressure on prices.

Figure 10 shows the impact of overall supply on ancillary service prices. Bid composition for the RU, SP and NS favored a continuation of similar pricing to January. The reduction in SP and NS supply came mostly in price brackets above market prices. Thus, the decrease in supply had little impact on price except in a handful of hours. Bid composition for RD was skewed toward lower prices in February than in January due to the entry of supply in the $5-15/MW bracket.

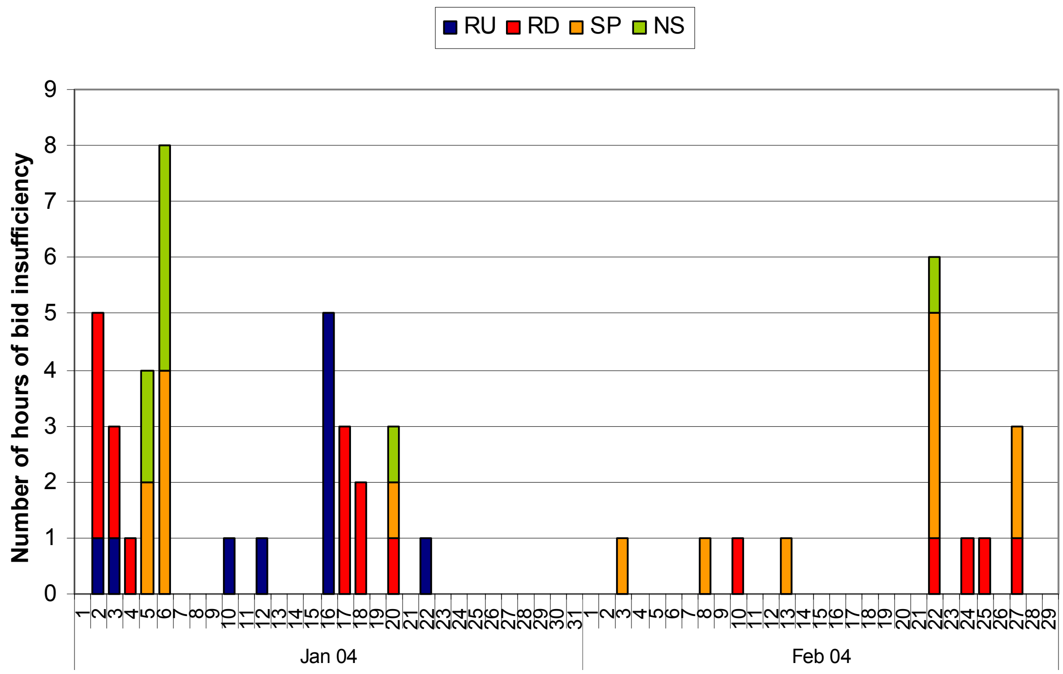
Figure 7. A/S Bid Volume by Price Bin through Feb-04



Bid insufficiency declined by 59 percent from January to February. The "flattening" of the daily load profile continues to drive this decline. As the morning and evening load peaks become less intense, online resources are better able to provide the necessary upward reserves (RU, SP, NS) to meet system requirements.

Bid insufficiency in the RD markets usually occurs overnight. A slight increase in off-peak loads through the middle of February brought additional downward capacity into these markets causing RD bid insufficiency to decrease from January. There were a few hours of bid insufficiency at the end of February in the SP and NS markets. This caused a slight increase in prices in those markets at the end of the month. Similarly, the absence of bid insufficiency in the regulation markets contributed to lower prices in RD and would have led to lower prices in RU if not for the previously discussed interaction between RU and RMR energy. Figure 11 shows the frequency of bid insufficiency for February.

Figure 8. Frequency of Bid Insufficiency in Feb-04



IV. Interzonal Congestion Markets

Inter-zonal congestion costs were $1.1 million in February, a slight decrease from the $1.4 million reported in January. The Palo Verde intertie was frequently congested due to heavy demand for energy from the Southwest. Palo Verde incurred approximately $553,000 in congestion costs, accounting for half of the total congestion cost for the month. Other paths with significant positive congestion costs were the California-Oregon Intertie (COI) and Mead branch groups.

Palo Verde was congested on February 1, 3, 5, 12-13, and 16-19. Similar to previous months, market participants attempted to import cheaper energy from the southwest region during the winter months with the effect that the submitted initial day-ahead schedules exceeded the import capacity of the line. Congestion prices, however, were modest, and the highest congestion price reported was $5/MWh reported on February 3. For most hours in the month, the line had an import capacity of 2,823 MW.

In contrast to Palo Verde, the congestion on Path 26 (North-South) decreased considerably in February compared to recent months. Path 26 was only congested one percent of the time in February. On most days, the north to south capacity of the line was rated at 3,000 MW, which helped to minimize congestion.

COI and Mead are also incurred significant congestion costs in February. The import capacity on COI fluctuated considerably until mid-February. On several different occasions, the import capacity was derated from 4,800 MW to 3,000 MW due to scheduled maintenance work. Derates directly contributed to congestion, especially between February 3 and 5, when congestion prices on COI reached there highest levels of $12/MWh. Congestion on Mead occurred primarily on February 2 and 18, with a maximum congestion price of $7/MWh.

Table 3. Interzonal Congestion Frequencies and Prices in Feb-04

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Congested (%)		Average Congestion Price ($/MWh)	
	Import	Export	Import	Export	Import	Export	Import	Export
CASCADE _BG	2	0	$0		0	0		
CFE _BG	0	0			0	0	$30	
COI _BG	20	0	$2		14	0	$12	
ELDORADO _BG	0	0			1	0	$3	
IID-SDGE _BG	0	0			0	2		$30
LUGOIPPDC_BG	0	0	$30		0	0	$30	
MEAD _BG	9	0	$3		9	0	$19	
N.GILABK4_BG	0	0			0	1		$30
NOB _BG	11	0	$0		8	0	$8	
PALOVRDE _BG	14	0	$3		7	0	$4	
PARKER _BG	0	0			0	0	$30	
PATH 15 _BG	9	0	$0		1	0	$2	
PATH 26 _BG	0	1		$2	0	2		$1
SUMMIT _BG	0	0	$0		0	0		

Table 4. Interzonal Congestion Costs in Feb-04

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	
CFE _BG	$0	$0	$751	$0	$751	$0	$0	$751	$751
COI _BG	$231,353	$0	$10,729	$0	$242,083	$0	$231,353	$10,729	$242,083
ELDORADO _BG	$0	$0	$5,758	$0	$5,758	$0	$0	$5,758	$5,758
IID-SDGE _BG	$0	$0	$0	$24,192	$0	$24,192	$0	$24,192	$24,192
LUGOIPPDC_BG	$5,581	$0	$0	$0	$5,581	$0	$5,581	$0	$5,581
MEAD _BG	$188,599	$0	$6,612	$0	$195,211	$0	$188,599	$6,612	$195,211
N.GILABK4_BG	$0	$0	$0	$27,908	$0	$27,908	$0	$27,908	$27,908
NOB _BG	$11,521	$0	$6,750	$0	$18,271	$0	$11,521	$6,750	$18,271
PALOVRDE _BG	$546,975	$0	$5,678	$0	$552,653	$0	$546,975	$5,678	$552,653
PARKER _BG	$0	$0	$1,411	$0	$1,411	$0	$0	$1,411	$1,411
PATH 15 _BG	$0	$0	$3,525	$0	$3,525	$0	$0	$3,525	$3,525
PATH 26 _BG	$0	$32,890	$0	$12,037	$0	$44,927	$32,890	$12,037	$44,927
Total	$984,029	$32,890	$41,214	$64,136	$1,025,243	$97,027	$1,016,919	$105,351	$1,122,270

V. Firm Transmission Rights Market

FTR scheduling. FTRs can be used to hedge against high congestion prices and establish scheduling priority in the day-ahead market. As shown in the following tables, a high percentage of FTRs was scheduled on some paths (70 percent on El Dorado, 75 percent on IID-SCE, 87 percent on LOGOIPPDC, 53 percent on LOGOMONA, 64 percent on Palo Verde, 100 percent on Silver Peak in the import direction, and 49 percent on Path 26). Southern California Edison Company (SCE1) and other municipal utilities own most of the FTRs on these paths.

Table 5. FTR Scheduling Statistics in Feb-04

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE _BG	167	29	167	167	17%
IMP	COI _BG	745	186	500	500	25%
IMP	ELDORADO _BG	510	355	355	355	70%
IMP	IID-SCE _BG	600	451	469	449	75%
IMP	LUGOIPPDC_BG	370	321	364	231	87%
IMP	LUGOMKTPC_BG	247	14	25	25	6%
IMP	LUGOTMONA_BG	167	89	92	52	53%
IMP	LUGOWSTWG_BG	93	31	46	28	33%
IMP	MEAD _BG	516	39	91	31	8%
IMP	NOB _BG	686	5	71	45	1%
IMP	PALOVRDE _BG	627	401	627	602	64%
IMP	SILVERPK _BG	10	10	10	10	100%
EXP	LUGOMKTPC_BG	247	3	5	5	1%
EXP	NOB _BG	664	33	83	83	5%
EXP	PATH 26 _BG	1425	695	1291	560	49%

*Only those paths on which 1 percent or more of FTRs were attached are listed.
** The FTRs on these paths were awarded to municipal utilities that converted their lines to CAISO operation and, therefore, were not released in the primary auction.

FTR Revenue per Megawatt. Table 5 summarizes the FTR revenue collected up through February 2004. Only a few branch groups reported significant positive revenue, namely COI, Mead, NOB, Palo Verde, and IID-SDGE (export). The FTR revenues on COI (import), Mead (import) and Palo Verde (import) were $256/MW, $216/MW, and $270/MW, respectively. Also, FTR revenue of $390/MWreported on IID-SDGE, resulted from hour-ahead congestion in the export direction on February 4 from HE100 and HE1300 with the congestion price of $30/MWh.

Table 6. FTR Revenue Per MW in Feb-04

Direction	Branch Group	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Cumm Net $/MW FTRREV – Imp	Pro Rated NET $/MW FTRREV - Imp	FTR Auction Price
		Net $/MW FTR Rev													
IMPORT	BLYTHE	69	0	231	1422	376	0	0	0	0	0	0	2,097	2,288	5,460
IMPORT	CFE	0	0	0	0	0	0	0	0	0	0	4	4	4	2,235
IMPORT	COI	723	536	299	138	440	192	352	100	284	0	256	3,321	3,623	59,484
IMPORT	ELDORADO	0	0	1	0	0	268	516	248	576	0	5	1,614	1,761	33,888
IMPORT	LUGOIPPDC**	272	0	0	5151	8	0	30	2	0	4	15	5,482	5,981	0
IMPORT	LUGOTMONA**	0	715	7	0	15	310	461	24	4	0	0	1,537	1,677	0
IMPORT	LUGOWSTWG**	3	0	0	0	0	9	0	0	261	0	0	273	298	0
IMPORT	MEAD	166	0	14	150	85	137	158	4	3	25	216	957	1,044	46,920
IMPORT	NOB	249	203	68	96	118	42	68	5	86	23	25	983	1,072	73,470
IMPORT	PALOVRDE	233	15	5	251	355	413	49	249	139	289	270	2,269	2,475	88,167
S-N	PATH 26	0	0	5	0	0	0	0	0	0	0	0	5	5	1,470
IMPORT	SUMMIT	108	0	0	0	0	0	0	0	0	0	0	108	118	2,600
EXPORT	IID-SDGE	0	480	0	0	5651	0	0	0	0	0	390	6,521	7,114	364
EXPORT	NOB	0	0	0	0	0	0	3	0	21	111	0	135	147	5,085
N-S	PATH 15 **	0	5	0	0	0	0	0	0	0	0	0	5	6	0
N-S	PATH 26	1147	1500	224	780	572	113	1433	1	41	324	20	6,156	6,716	34,408
EXPORT	SILVERPK	0	0	720	0	0	0	0	0	0	0	0	720	785	100

* We estimate pro-rate annual FTR revenue 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, therefore, were not released in the primary auction.

VI. Issues Under Review

Pacific DC Intertie and the Sylmar substation. The 3100 MW, 500 kV Pacific DC intertie (also known as the branch group NOB, Nevada Oregon Border) runs from the Celilo substation in the North West to the Sylmar substation close to LADWP's area. It plays a crucial role in the WECC by providing a substantial amount of North-South transfer capacity, which allows the WECC to reap the advantages of seasonal variations between the winter peaking hydro systems of the North West and the summer peaking thermal systems of California. The ISO indirectly controls rights to approximately 2070MW (1416MW) of the available 2990MW N-S (2860 S-N) capacity of the line, depending on conditions, and allows scheduling in its system to that limit. In late 1999 BPA initiated a process to reassess the viability of the PDCI in light of its aging equipment. The end result was a commitment by LADWP and BPA to retain the line at its existing rating of 3100 MW. This would entail the replacement or upgrade of much of the equipment at both ends of the line, at Celilo and Sylmar. This replace and repair process is currently underway and has been for some time now, however the main body of the process started in September 2003 and is scheduled to run until almost the end of the 2004. In the last week of September 2003 line curtailments began and by October scheduling limits for the ISO were reduced to about 725 MW in each direction, where they have stayed to this date. Most of this is due to work on the Celilo station in the North West. Initial indications are that the ISO scheduling limits will probably rise to approximately 1400 MW between March 31st 2004 and September 30th 2004, after which time the line will be physically out for October-December. Contemporaneously with the line limits, transformer Bank E at Sylmar was down for three weeks in December 2003, and this caused substantial congestion. Although the ISO does not forecasting congestion, it is possible that congestion may re-emerge at least twice:

1. During the spring when the North West is generation rich due to the snow melt, and California is generation constrained due to the spring maintenance season prior to the heavy loads of summer; and
2. During the October to December period when the line is completely down due to final testing.

The Department of Market Analysis continues to actively monitor these planned outages for the effects they will have on the inter-zonal and intra-zonal congestion within our service territory.

Negative-priced DEC Bids at Palo Verde. The ISO has been examining the rationale and prevalence of zero or negatively priced bids for decremental energy at the Palo Verde tie-point starting in the fall of 2003. Under most market conditions, zero or negatively priced bids for decremental energy are *per se* anomalous, since they effectively are demands for payment to consume energy. In some cases, however, factors that may have contributed to such bid prices may in fact be cost-based, and include: extremely weak demand for “odd lots” of real time energy on short-term notice in the Southwest, and the transaction costs of arranging such sales once DEC bids are accepted. Meanwhile, the ISO was concerned that a lack of competition also contributed to low bid prices for decremental energy. In the last few months, the number of suppliers and the volume of decremental energy bid have increased as have bid prices. Consequently, the market appears to be more competitive. The ISO is also taking steps to publish information on prices paid for decremental energy procured out-of-sequence (OOS), in an effort to improve the supply of decremental energy bids when prices drop. The general issue of whether zero or negatively priced bids may violate any FERC market rules, or should be subject to any other actions by FERC, has been referred by the ISO to the FERC Office of Market Oversight and Investigations.

FERC Order on Refunds. The Mitigated Market Clearing Price (MMCP), to be used in calculating refunds for the period from October 2, 2000, to June 21, 2001, pursuant to the methodology and data described in the FERC’s Orders of December 12, 2002, and November 17, 2003, has been calculated and posted on the ISO website (http://www.caiso.com/pubinfo/currentissues.html). Detailed documentation and underlying data needed to review the calculations was prepared and has recently been released. The ISO hopes that the MMCP calculations posted on the ISO website can undergo thorough review by parties in the refund proceedings so that any issues or disputes may be resolved *before* the settlement re-run based on these prices, which is scheduled to begin in this summer.

Analysis and Input on MD02 Market Design Issues. DMA has provided review and input on the MD02 filing to FERC on proposed modifications to RUC, Must Offer, and A/S Procurement. The Market Surveillance Committee (MSC) has been involved in providing input on the RUC provisions.

Prof. Frank Wolak, MSC Chairperson, has expressed concern that the RUC proposal, as recently modified by the ISO, is getting extremely complicated. He favors eliminating the recent constraint that the ISO imposed on HA exports. Dr. Keith Casey, the ISO's Manager of Market Analysis and Mitigation, attended the FERC Technical Conference on March 3-5. MSC members Prof. Wolak, Prof. Jim Bushnell, and Prof. Brad Barber also attended on various days. DMA staff participated in a conference call with FERC staff and MSC members Prof. Wolak and Prof. Benjamin Hobbs, to get a preview of the local market power mitigation proposal in preparation for the conference.

Transmission Methodology. DMA led a stakeholder working group conference call on modeling market power in transmission studies to provide the participants with a better understanding of the ISO is approaching the modeling of market power and the challenges associated with this issue. DMA has completed an initial benchmark through 2008 of Plexos simulation software, and compared it to the results from another simulation software package. A detailed comparison will continue into March. The ISO has been finalizing methodologies, incorporating input from MSC members, and will begin implementation in Plexos.

FTR Auction. ISO management informed DMA that a small amount of private information might have been compromised in the annual FTR auction in February 2004, which was then suspended mid-auction. After conducting an analysis, DMA was not able to detect any evidence that the FTR auction was compromised by this security breach. The Auction has since resumed.

Market Surveillance Committee Reappointments. At its February 26 meeting, the ISO Board of Governors reappointed Prof. Hobbs to a three-year term, and extended Prof. Barber's current term for two years.