# Memorandum

**To:** ISO Board of Governors

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

**cc:** ISO Officers, ISO Board Assistants

**Date:** February 20, 2004

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

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

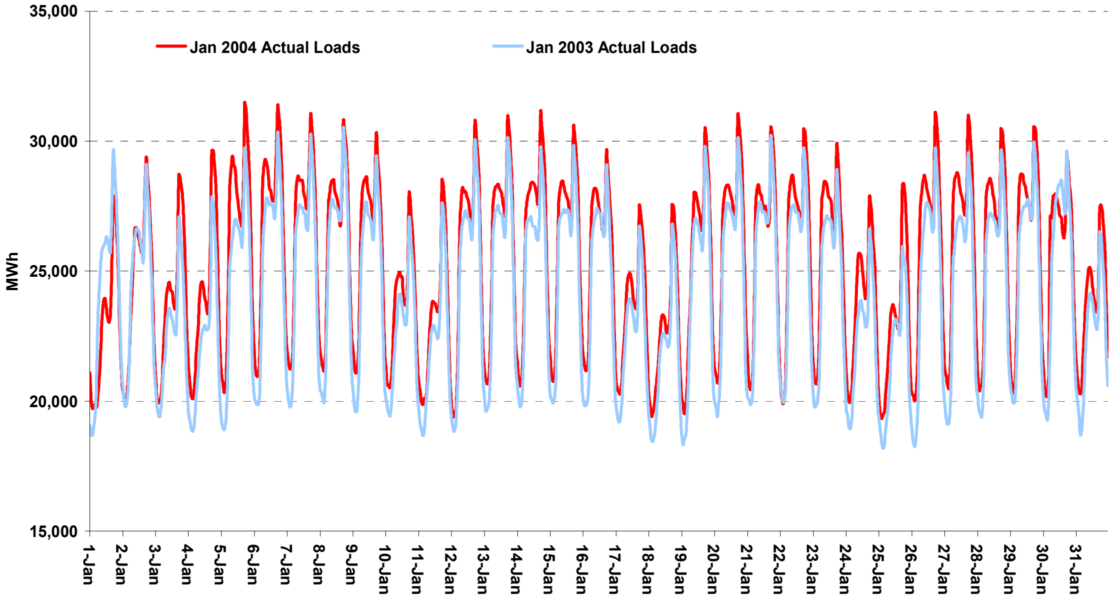
## Executive Summary

The ISO's wholesale electricity markets continued to perform well in January with ample supply providing competitive market outcomes. Average loads were 4.3 percent higher and the monthly peak was 3.2 percent higher than in January of last year. January's higher loads continued the trend of average loads reaching levels 3.6 percent higher during the second half of 2003 compared to the same period in 2002. The DMA attributes this load growth to a recovering economy. Real-time energy prices remained moderate at $70/MWh with day ahead regional bilateral prices averaging $50/MWh, closely following variations in natural gas prices. Within-zone congestion and ancillary service reserve bid insufficiency continued to be problematic, although the severity of each declined significantly in January from December levels. Total intrazonal congestion costs dropped to approximately $5million from $16.7 million in December. This significant decrease was due largely to the Sylmar substation in the Los Angeles area returning to its full capacity rating. This alone reduced incremental intrazonal congestion costs from $9.7 million in December to approximately $500,000 in January. The frequency of bid insufficiency in the ancillary services markets also decreased due to a slight reduction in average load from December levels, combined with a larger reduction in peak loads. Finally, due to high levels of imports from the southwest and line derates, congestion costs attributed to bottlenecks between zones (interzonal congestion) increased slightly from December levels to approximately $1.5 million.

## I. Market Trends

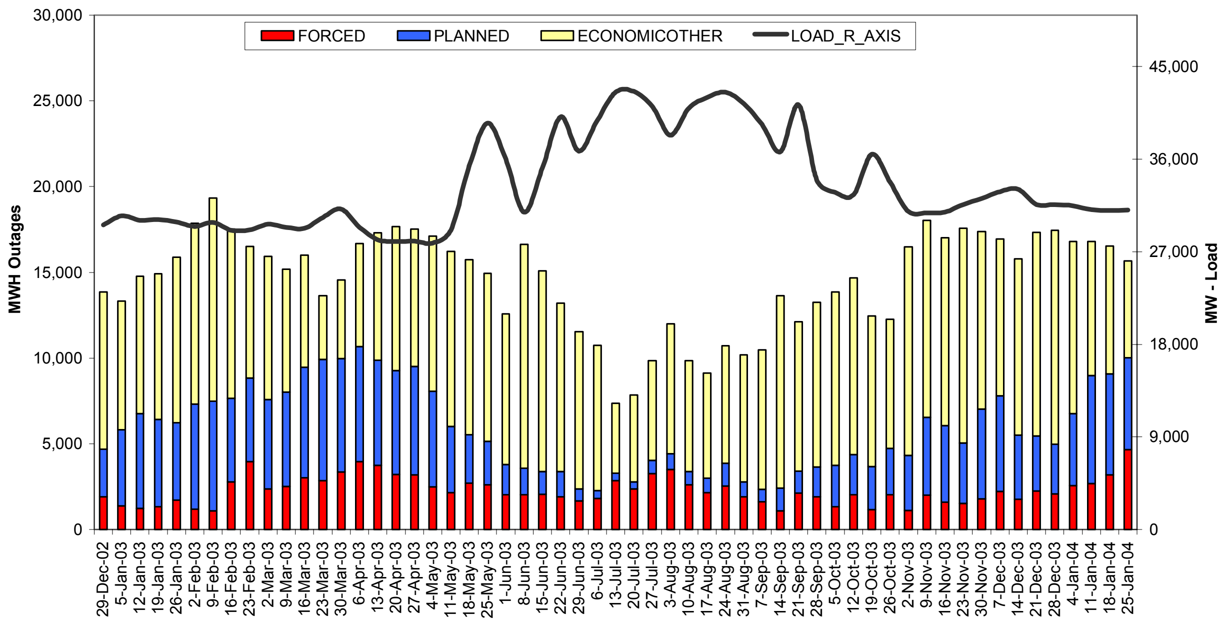
The average daily load was 25,211 MW in January 2004, a 4.3 percent increase from January 2003. This pattern was consistent for nearly every day of the month. The peak load for the month was 31,460 MW, a 3.2 percent increase over the January 2003 peak. As we observed in the January 16 Market Analysis Report for December 2003 , the winter load pattern has a sharp load ramp between 5:00 and 7:00 p.m., during which the load can increase 5000 MW. Managing such steep ramps continues to cause price spikes in the real-time imbalance market. The following chart compares loads in January 2004 to those in January 2003.

**Figure 1.** ***Loads increased 4.3 percent since January 2003***
**Hourly Loads: January 2004 v. January 2003**




**Plant Outages.** Lower loads in January compared to December allowed several large units to be taken out for seasonal maintenance. Both forced and planned outages increased in January to nearly 10,000 MWs by the end of the month. Several units, primarily in southern California, continued to be held on-line pursuant to the "Must-Offer" obligation, directed by the Federal Energy Regulatory Commission in its Order of June 19, 2001, and other controlling Orders. Units not required to be available may be granted waivers to the "Must-Offer" obligation. The following chart shows weekly average MW out, by type of outage, in January.

**Figure 2. Weekly Outages by Type**
***Scheduled Outages Increased Due to Seasonal Maintenance***




## II. Real-Time Market

Prices for real-time balancing energy in January 2004 were similar to those seen in December 2003. They remained at levels seen consistently throughout 2003. Meanwhile, the trend we are observing of real-time energy being primarily dispatched in the decremental direction persisted.

The market price for incremental energy, the amount the ISO pays generators to increase output when schedules are short of actual load, averaged $70.17/MWh in January compared to $69.35/MWh in December. Total awarded energy in January was 108 gigawatt-hours (GWh), or an average of 144 MW daily, an increase of 32 percent from December.

The market price for decremental energy, the amount the ISO collects from generators when it allows them to avoid producing energy during periods when schedules exceed actual load, averaged $20.53/MWh in January 2004, compared to $15.69/MWh in December 2003. Total awarded energy in January was 377 GWh, or 507 MW daily on average, an increase of 2 percent from December.

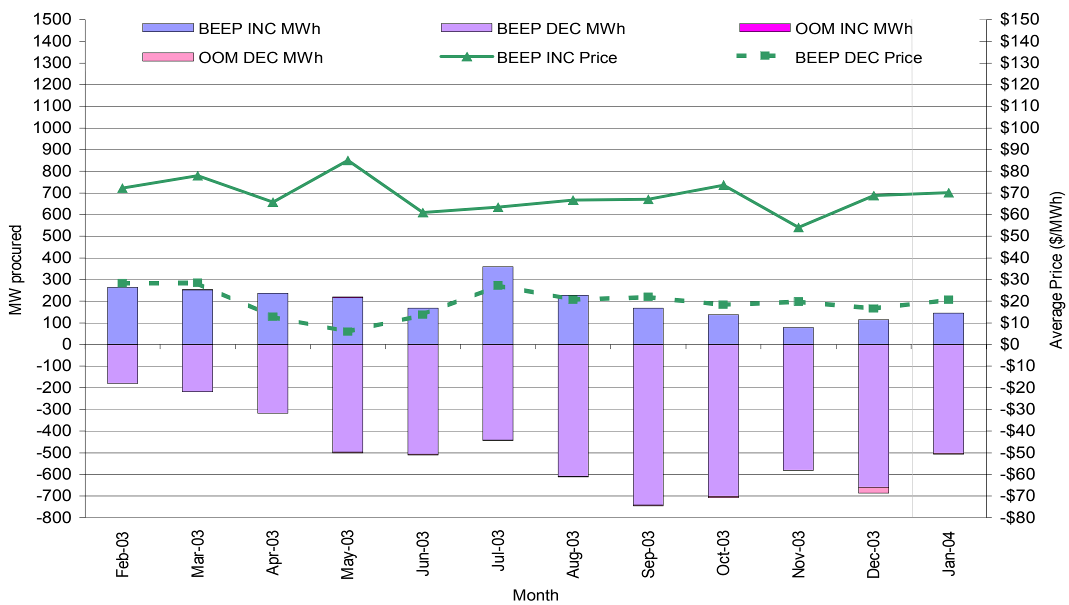
The following table shows average prices, total awarded energy, and average loads and underscheduling in January. The chart that follows shows the 12-month trend of average real-time prices and volumes.

**Table 1. Average Real-Time Balancing Energy Prices and Total Awarded, Average System Loads, and Average Deviation from Schedules, in January**

| | Overall Avg. Real-Time Price and Total Volume | | Avg. System Loads (MW) and Pct. Underscheduling |
|---|---|---|---|
| | Inc | Dec | |
| Peak | $ 71.50 | $ 21.34 | 27,030 MW |
| | 84 GWh | 243 GWh | -0.7% |
| Off-Peak | $ 65.44 | $ 19.05 | 21,573 MW |
| | 24 GWh | 134 GWh | -1.7% |
| All Hours | $ 70.17 | $ 20.53 | 25,211 MW |
| | 108 GWh | 377 GWh | -0.9% |

**Figure 3. *Real-time Market Remains Largely Decremental; Prices and Volumes Similar to Those in 2003***

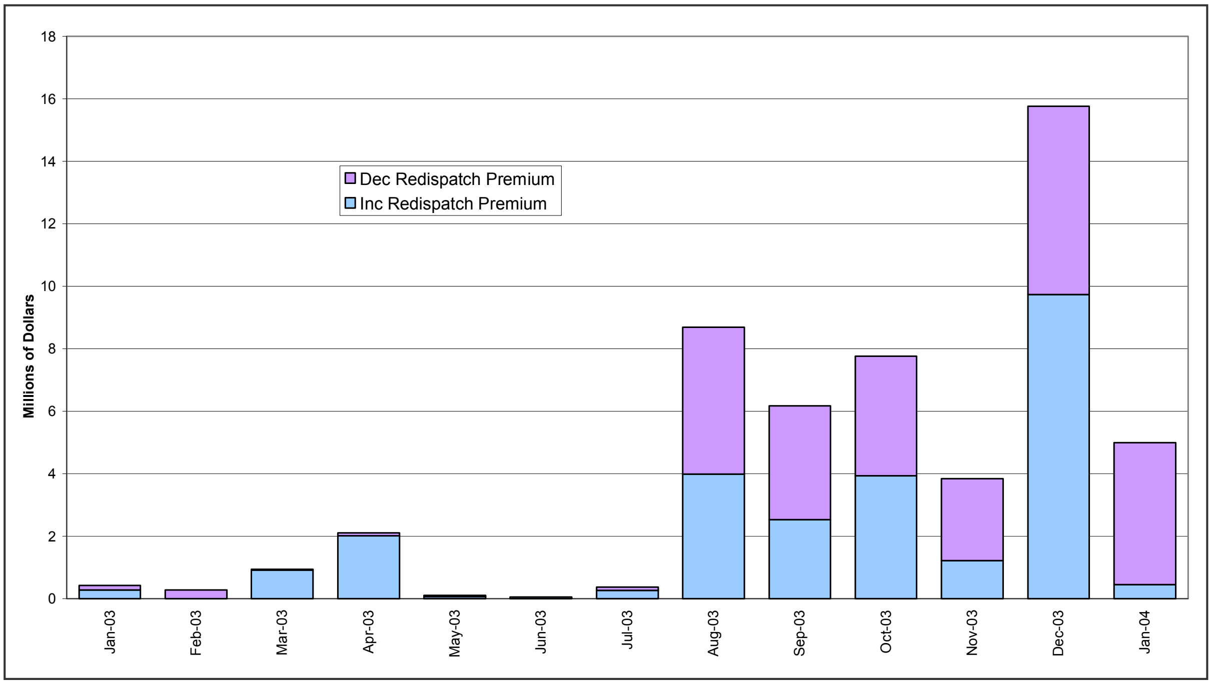
**Monthly Average Prices and Volumes in the Real-Time Market through Jan-04**




**Management of Congestion Within Zones: Out-of-Market (OOM) and Out-of-Sequence (OOS) Activity.** There was a significant increase in intrazonal congestion in December. This was primarily caused by the derating of the Sylmar substation. However, costs were significantly lower than in January. The Sylmar substation returned to service in late December resulting in a substantial decrease in incremental congestion. Decrementing generation located in northern Mexico resulted in the level of decremental OOS dispatches remaining constant. January OOS dispatches resulted in a net cost (re-dispatch premium) of approximately $5.0 million. Total OOS dispatch volume was 165 GWh (INC plus DEC) and the average redispatch premium was $30/MWh.[1]

Figure 4 below shows the monthly redispatch costs since January 2003. Intrazonal congestion costs increased significant beginning in August as new generation units came on line in northern Mexico combined with various substation derates in southern California. The significant decrease in incremental redispatch costs in January from December is a result of the return to service of the Sylmar substation.

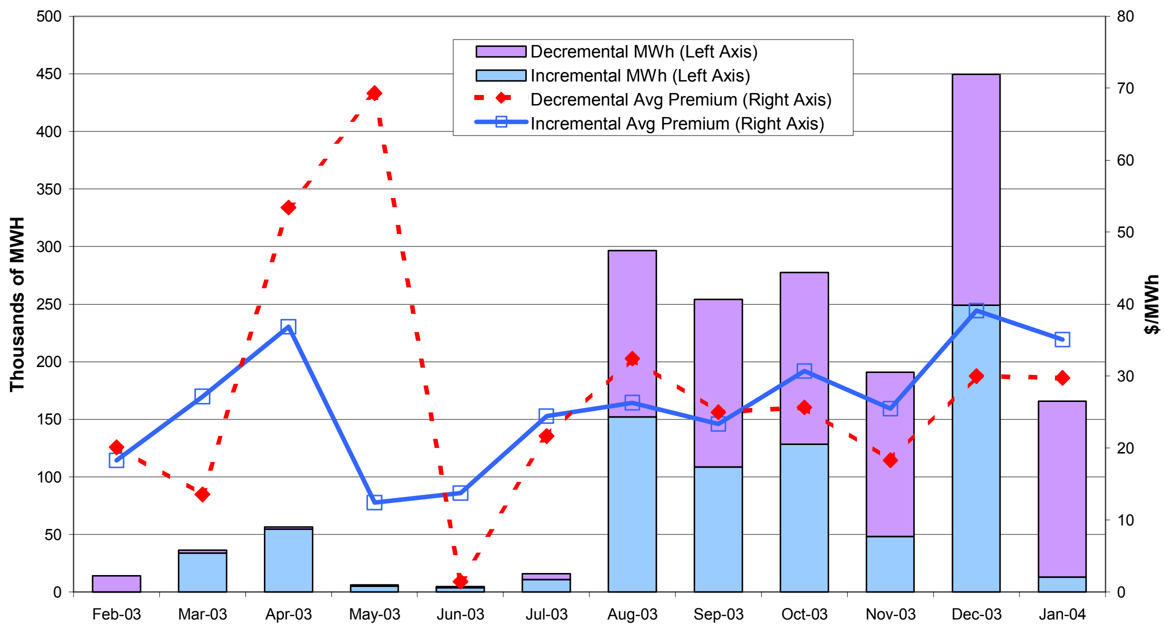
**Figure 4: Redispatch Costs by Month**




Redispatch costs tend to closely mirror the volume of OOS dispatches and the average redispatch premium paid. Figure 5 shows the OOS volume and average redispatch premium for recent months. DMA also tracks local market power mitigation (AMP LMPM), which resulted in moderate savings of $792 in January (or less than 0.2 percent of the redispatch premium). Amendment 50 mitigation measures for decremental dispatches resulted in a net redispatch premium over the market-clearing price (MCP) of $4.5 million.

[1] 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 reflects the increased cost of redispatch and any potential mark-up above marginal cost.

## Figure 5. Out-of-Sequence Volume and Average Redispatch Premium



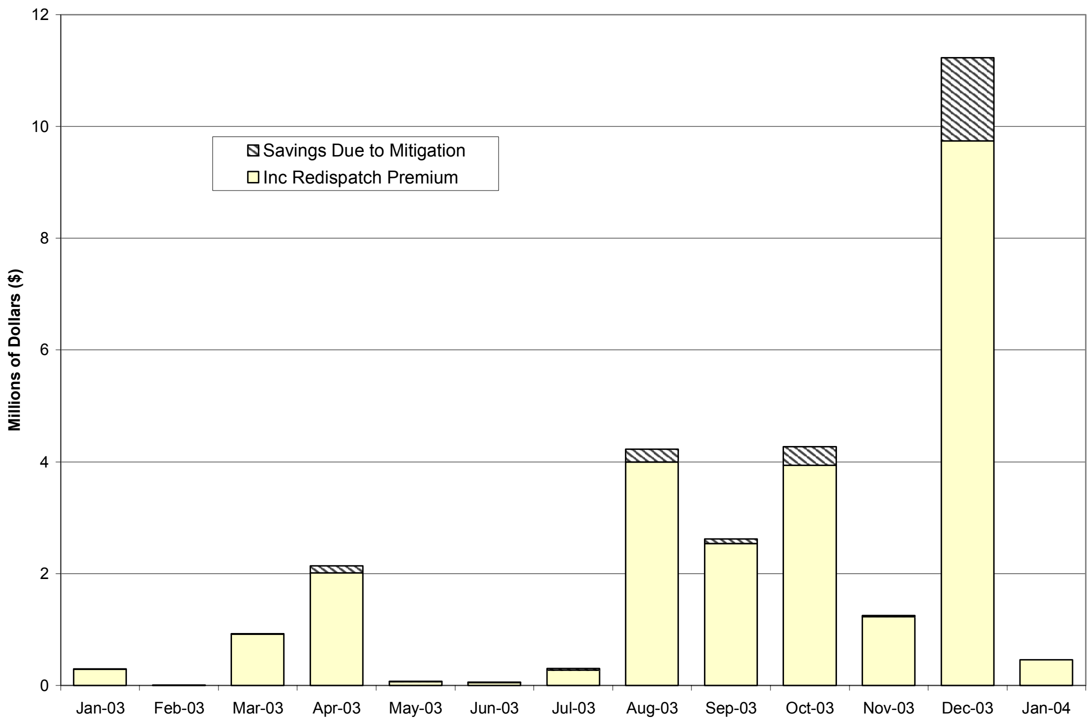

**Incremental OOS Dispatches.** ISO operators called a total of 13,093 MWh of incremental energy out-of-sequence (OOS) to address intrazonal congestion in January. Figure 10 shows this was the lowest level since July 2003. The average price paid was $68.66/MWh.The re-dispatch premium in excess of the MCP was approximately $460,000, or $35/MWh.

The small amount of incremental congestion that occurred was due to two reasons:

1. There were a number of congestion incidents related to the SCIT nomogram, which limits the amount of energy that can be simultaneously imported into Southern California.
2. There were incidental OOS calls due to transmission line and substation maintenance.

All incremental OOS dispatches are subject to mitigation. Figure 6 shows the re-dispatch premium and the savings due to mitigation of incremental dispatches. As shown in the chart, very little bid mitigation has taken place due to the large thresholds in AMP for local market power.

**Figure 6. Analysis of Incremental Mitigation Savings**




**Decremental OOS Dispatches.** A total of 152,646 MWh of decremental energy was dispatched out of sequence in January. This energy is settled according to the provisions of the Amendment 50 mitigation measures approved by FERC. The approximate re-dispatch premium in excess of the MCP was $4.5 million. As in previous months, almost all of the decremental activity was due to intrazonal congestion in the San Diego region. This congestion is due to the combined schedules of the new generation units located in northern Mexico and imports from Arizona exceeding the limitations of the local transmission infrastructure in the area.

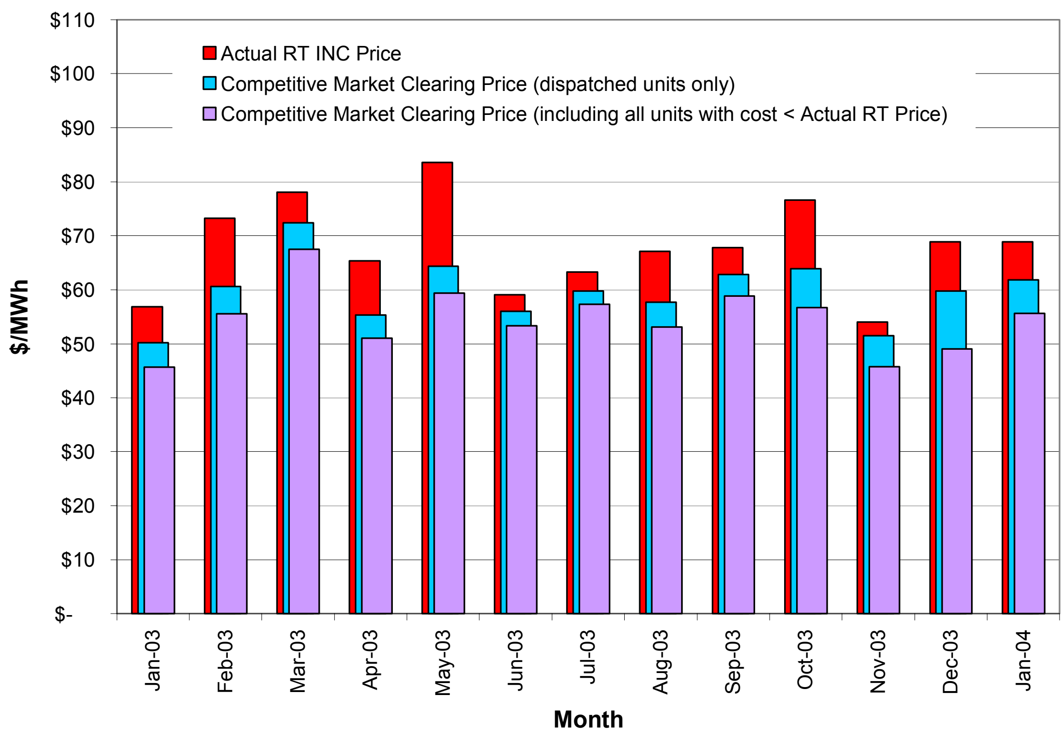
**Real-time Market Competitiveness.** A measure of market competitiveness is the extent to which market prices are above what would be prices set under competitive conditions. The Department of Market Analysis is currently using two estimates of competitive baseline prices based upon real-time incremental balancing energy only. This is due to the DMA's inability to access short-term bilateral forward contract information. The two metrics together represent a range of estimated competitive baseline prices to be compared to actual real-time imbalance energy market outcomes.

The first metric, represented by the light blue bar in Figure 7 below, is a conservative measure of a competitive baseline price that only takes into account generation units that were dispatched by the ISO. By only including dispatched units in determining the competitive baseline price, this metric does not account for any possible economic withholding. This methodology assumes that high-priced bids correspond to high costs, and therefore results in a higher estimated competitive baseline price. The second measure, represented by the purple bar, is a more liberal measure in that it not only includes units that were dispatched, but also units whose estimated marginal costs are less than the market-clearing price yet submitted bids in excess of the market-clearing price and consequently were not awarded dispatch instructions. Therefore, this second index includes an estimate of the impact of potential economic withholding on the competitive baseline price, which has the effect of increasing the realized real-time price. This methodology adjusts for economic withholding by reoffering those bids at their estimated marginal cost and dispatching units in the resultant merit order. Please see the Market Analysis Report for September 2003 for more information regarding the markup index for real-time energy. The two indices taken together represent a range of possible competitive baseline prices.

Monthly average price-to-cost markup using the methodology that accounts for possible economic withholding was approximately $13.26/MWh (23% above cost) in January 2004, compared to $19.80/MWh (40% above cost) in December 2003, and $12.93/MWh (23% above cost) for all of 2003. The average markup using the more conservative, non-withholding methodology was approximately $7.03/MWh (11% above cost) in January, compared to $9.13 (15%) in December, and $8.33/MWh (14%) for all of 2003.

The following chart compares both estimates of the competitive baseline price to the actual incremental real-time price between January 2003 and January 2004.

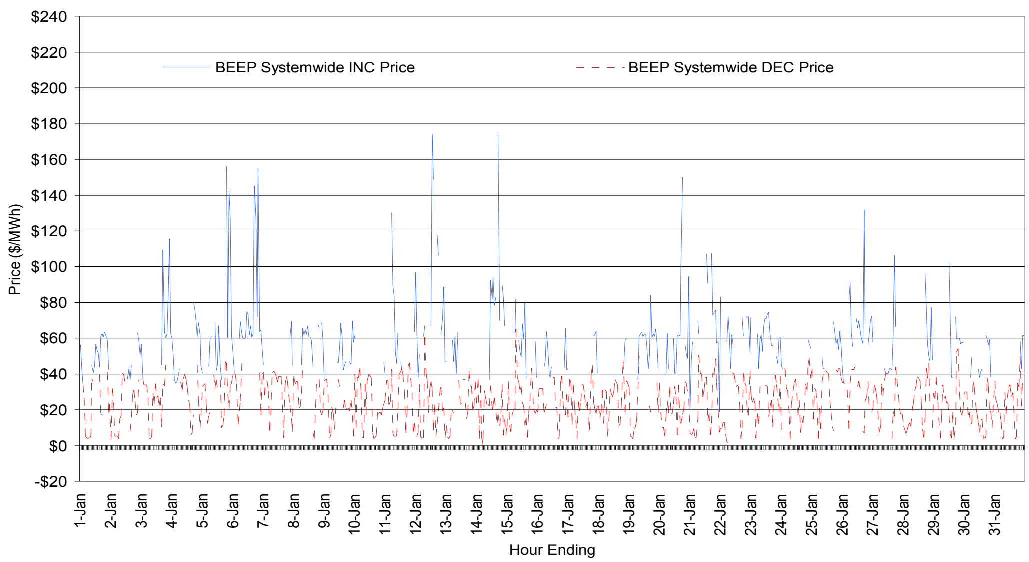
**Figure 7. Competitiveness Measure for Real-time Market Bounded by High and Low Benchmark Estimates**




**AMP Performance and Price Spikes.** There were several price spikes in January. Most occurred within Southern California and were due to constraints such as the Southern California Import Transmission Nomogram (SCIT), a technical limit on the total inflow of energy into Southern California. Winter system load patterns resulted in high imports from the southwest into Southern

California and high south to north flows on Path 15 between Southern and Northern California. Many spikes occurred during the sharp evening ramp period, as residential heating, lighting, and appliance use caused load to increase 5,000 MW or more between 5:00 and 7:00 p.m. Contrary to trends seen in recent months, real-time markup was dispersed among many hours. The top ten markup hours accounted for approximately 31 percent of January's total estimated markup costs. The following chart shows hourly average incremental and decremental prices for balancing energy in January.

**Figure 8. Hourly Average Balancing Energy Prices in January**




## January Real-Time Market Price Spikes

On January 3, the ISO system-wide price for incremental balancing energy spiked to between $100 and $125/MWh from 9:50 to 10:40 p.m., as the ISO was required to skip bids from inflexible generation units requiring dispatch periods of 1 hour or longer. The unit that set the $125/MWh price has done so many times before in similar situations. The hour ending at 11:00 p.m. was the highest-markup hour in January, accounting for approximately $65,000 in markup, or nearly 5 percent of the monthly total.

On January 5, the ISO system-wide price for incremental balancing energy was $167/MWh for 50 minutes between 7:00 and 8:00 p.m. and $150/MWh for 50 minutes between 9:00 and 10:20 p.m. During those hours, the ISO conserved scarce operating reserves by bypassing real-time energy bids from awarded ancillary services resources. The units bidding those prices would have failed the AMP Conduct Test had the hour-ahead predicted price screen been above $91.87/MWh and the test been applied. However, since some high-cost units were dispatched, neither of these hours exhibited extraordinary markup.

On January 6, the ISO system-wide incremental price was $155/MWh between 5:30 and 6:30 p.m., and again between 8:00 and 9:00 p.m. Imported energy from Arizona on the Palo Verde branch group into Southern California reached the path's rated limit and the incremental bid stack was depleted. Again, the price-setting unit would have failed the AMP Conduct Test had the price screen been above $91.87/MWh. These hours accounted for approximately $143,000 in markup, or 10 percent of the monthly total.

On January 11, the NP15 incremental price was $133.36/MWh between 5:10 and 6:30 a.m., as a 500/230 kilovolt transformer bank at the Gates substation at the southern end of Path 15 relayed, instantly reducing the south-to-north transfer capability on Path 15 from over 3000 MW to 1660 MW. The ISO dispatched operating reserves and issued manual OOM calls to mitigate the contingency. This spike accounted for approximately $67,000 in markup, or 5 percent of the monthly total. See Section VII below, Issues Under Review, for more information related to the market impacts of this event.

On January 12, the ISO dispatched contingency reserves and separated the Northern and Southern California zones. Reserves were required due to SCIT, after a Navajo-Crystal 500 KV line tripped. The SP15 incremental price was between $155 and $175/MWh from 2:10 to 3:20 p.m. This spike accounted for approximately $21,000 in markup, or roughly 1 percent of the monthly total.

On January 14, the SP15 price was between $155 and $175/MWh from 5:10 to 6:00 p.m., as zonal prices between Northern and Southern California differed due to SCIT mitigation. The bid stack was exhausted, and the ISO made OOM calls to increase the generation needed to meet load during the sharp load ramp. The spike accounted for approximately $25,000 in markup, or roughly 2 percent of the monthly total.

On January 20, the SP15 incremental price reached $150/MWh between 6:00 and 7:00 p.m. as a loss of generation in another control area resulted in loop flows and north-to-south congestion along Path 26. The resultant markup was less than $9,000, as the marginal unit setting the MCP was one of the most expensive within the ISO control area.

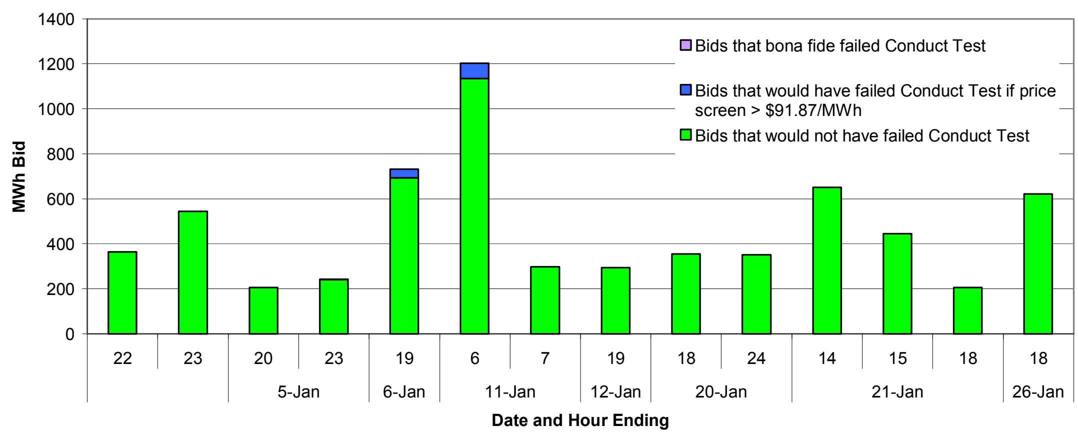
On January 21, the SP15 incremental price was $107.89/MWh from 1:10 to 2:20 p.m., and again from 5:30 to 6:00 p.m. The former spike was due to SCIT mitigation; the latter followed a split in the real-time bid stack due to real-time congestion between Northern and Southern California. The estimated markups for these spikes are $41,000 (nearly 3 percent) and $8,000 (less than 1 percent) respectively.

Prices in SP15 spiked between $110.86 and $150/MWh on each day between January 26 and 28, from 5:30 to 6:00 p.m. These were due to SCIT and overloads of Path 26 in the north-to-south direction. The markup on January 26 was nearly $51,000, or roughly 4 percent of the monthly total; the others were both below 1 percent.

**AMP Performance**

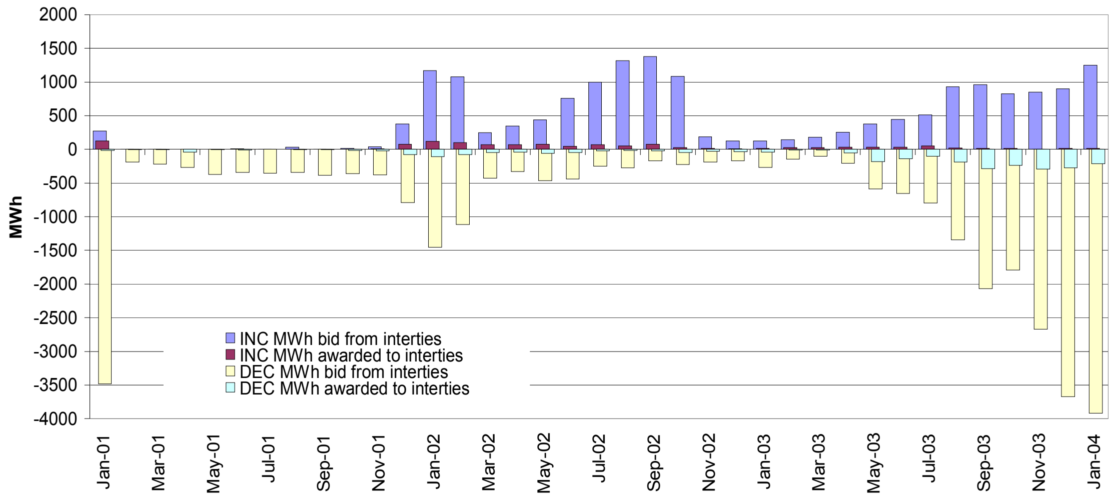
The automatic mitigation measures (AMP), implemented in October 2002, continue to have little or no impact on market outcomes. Ample supply has resulted in competitive market outcomes since the new market power mitigation measures where put into place. In those few instances where significant, although short lived, price spikes have occurred, the AMP measures often did not come into play due to difficulties in forecasting next hour real-time imbalance energy prices. If the real-time price is estimated to be less than $91.87/MWh, the current market rules require that AMP not be run for that hour. As price spikes often occur as the result of unexpected system constraints, AMP is often not implemented during real-time price spikes. The following chart shows the impact of the price screen by showing the volumes of bids that actually failed the AMP Conduct Test, bids that would have failed the Conduct Test had the hour-ahead predicted price screen exceeded $91.87/MWh, and bids that would not have failed the Conduct Test in any circumstances. The chart looks selectively at hours in which the price exceeded $100/MWh and the estimated markup exceeded at least 40 percent of estimated cost (using the new real-time markup methodology).

**Figure 9. AMP Detection of Bidding Behavior in Hours with Price Spikes and Markup:**
***AMP Would Have Identified Two of Fourteen Spike Hours***
***If Price Screen Did not Apply***




**Import bids into the Real-Time Market.** Imports continue to grow in volume in the ISO's real-time market. This has been the trend since June of last year when the Federal Energy Regulatory Commission rescinded its requirement that importers bid incremental energy at a price of $0/MWh. For more information on these rule changes, please see the Market Analysis Report for August 2003 dated September 19, 2003. Despite a January 1st increase in grid management charges to suppliers outside of the ISO control area, import decremental bid volume has increased as well. The following chart shows monthly average import and export volume in the real-time market.

**Figure 10. Incremental and Decremental Intertie Bid Volume in the Real-Time Market Monthly Averages through January 2004**




## III. Ancillary Services (A/S) Markets

- ***Prices decreased 19 % on average for all services while overall demand increased from December 2003 to January 2004.***
- ***Operating reserve supply increased on average from December 2003 to January 2004.***
- ***Frequency of bid insufficiency decreased from December 2003 to January 2004.***

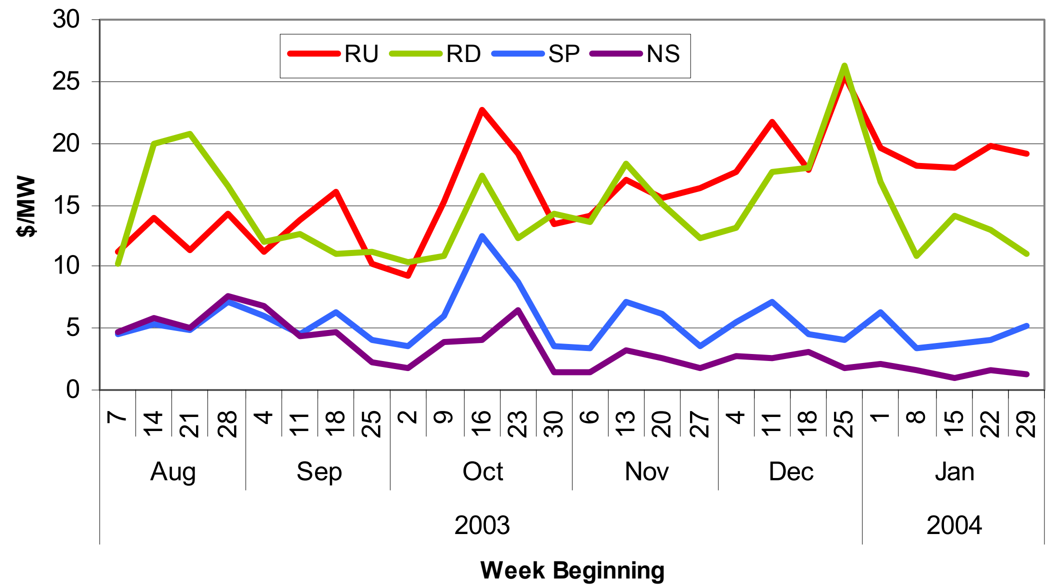
**Market Prices.** A month of increasing supply resulted in decreasing prices in the Ancillary Services markets. Overall demand increased 1.2% in January 2004 when compared to December 2003, while overall supply increased by 8.9%. The result was a 19% decrease in overall prices for ancillary services. The overall increase in supply resulted in noticeable declines in prices for spinning (SP) and non-spinning (NS) reserves; prices for SP were 21% less while NS prices declined by 40%.

**Table 2. A/S Average Requirement and Price**

| | Average Required (MW) | | | | Weighted Average Price ($/MW) | | | |
|---|---|---|---|---|---|---|---|---|
| | RU | RD | SP | NS | RU | RD | SP | NS |
| Dec 03 | 370 | 388 | 714 | 653 | $ 20.35 | $ 18.19 | $ 5.42 | $ 2.54 |
| Jan 04 | 363 | 402 | 708 | 676 | $ 18.94 | $ 13.57 | $ 4.29 | $ 1.54 |

Prices in the regulation markets – regulation up (RU) and regulation down (RD) – also declined. Weekly prices in these markets have been quite volatile. Hourly bid insufficiency is a major factor causing pricing volatility in the regulation markets. January pricing declines are due to the decrease in frequency of bid insufficiency from December 2003 to January 2004. The following chart shows weekly average prices in the ancillary services markets, highlighting the price volatility in the regulation markets during this two-month period.

**Figure 11. A/S Weekly Weighted-Average Prices December 2003 through January 2004**

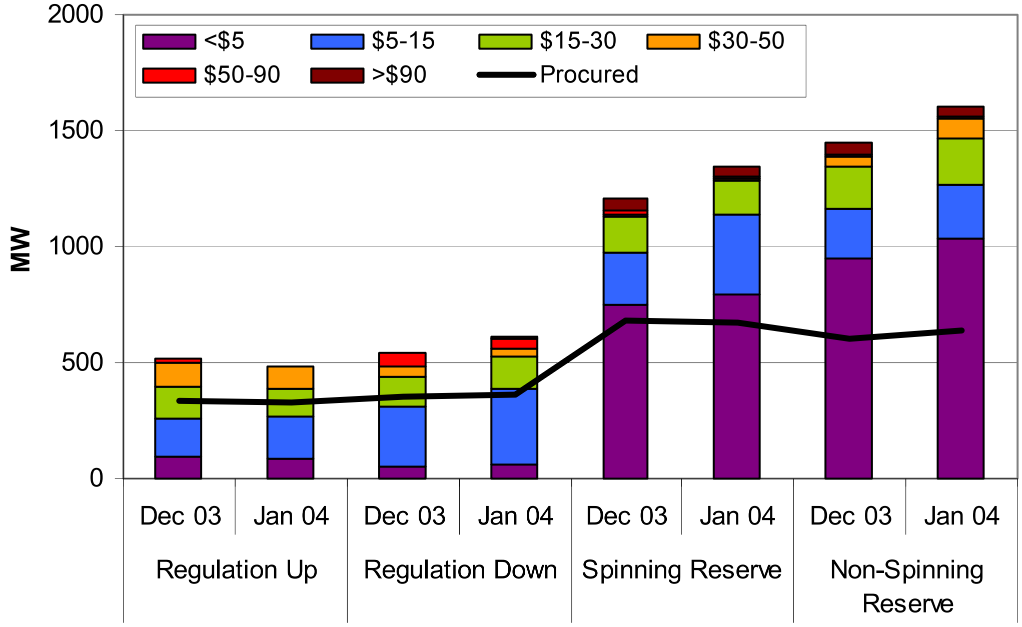



**Ancillary Service Market Supply.** Market supply was characterized by a decline in the frequency of bid insufficiency. Another major factor influencing supply was increasing bid volume in the operating reserve (SP and NS) markets.

The reduction in bid insufficiency in regulation up, spin and non-spin was caused by a slight reduction in average load combined with a larger reduction in peak loads. These reductions allowed more upward capacity to be unloaded on regulation providing units. This corresponded to an increased frequency of regulation down bid insufficiency, which has driven a more volatile pattern of prices.

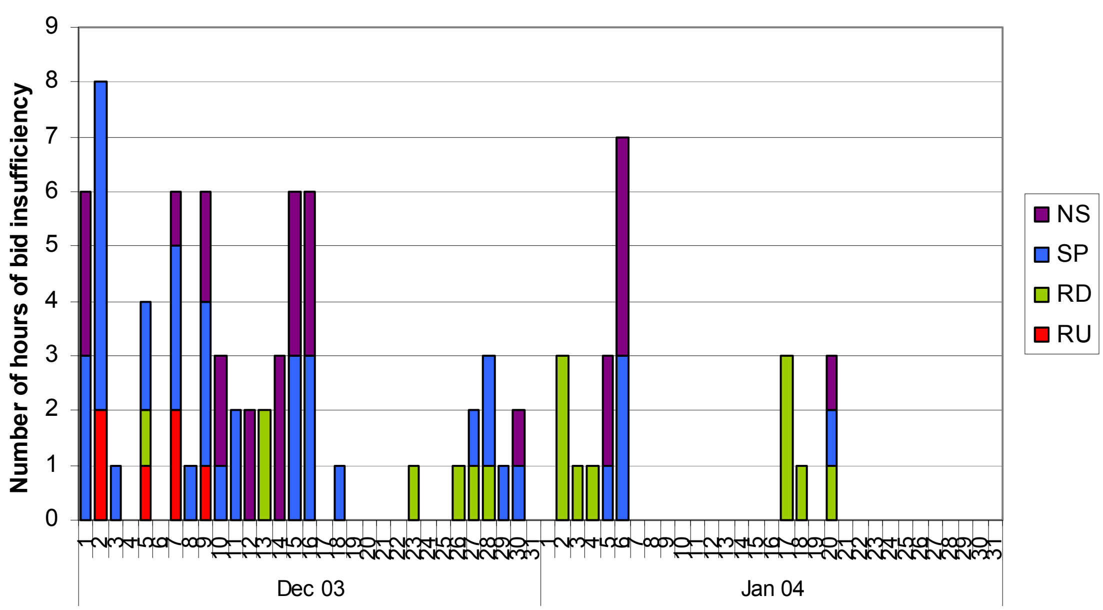
The following chart shows the impact of the overall supply picture on ancillary service prices. Bid composition for the RD, SP and NS markets demonstrates the trends toward lower prices realized in the markets. Bid composition for RU is skewed toward higher prices in January than in December 2003 on average. However, there were no instances of bid insufficiency in RU during January resulting in a decrease in price.

**Figure 12. Ancillary Service Bid Composition, December 2003 - January 2004**




The following chart shows that bid insufficiency has declined substantially. When comparing the previous chart of weekly average prices to the following chart of daily frequency of bid insufficiency, one can see there is relationship between instances of bid insufficiency and changes in the weekly average price of regulation products. The weekly average prices of operating reserves are sensitive to frequency of bid insufficiency but the variation of prices is not as dramatic.

**Figure 13. Frequency of A/S Bid Insufficiency**



## IV. Interzonal Congestion Markets

- ***Palo Verde and Path 26 continue to be the two most congested paths***
- ***Hour-ahead congestion price spikes on Path 15 due to derating***

Congestion costs on major interfaces amounted to $1.46 million in January, a modest increase from $1.2 million reported in December 2003. Path 26 and Palo Verde's $585,000 and $677,000 in congestion costs in January accounted for more than 90 percent of the month's total interzonal congestion costs. This was due primarily to winter system loading patterns that included high imports from the southwest on Palo Verde lines and high flows on Path 26. The other major intertie branch groups that had positive congestion costs in January were COI, NOB, Path 15, Mead, and LUGOIPPDC branch groups.

Palo Verde was congested on January 6, 9, 20, 23, and 27-29. Similar to previous months, the scheduled flow had either exceeded or had been very close to the import capacity of the line in most hours. The highest congestion price reported was $10/MWh on January 6. The line had been derated by 120 MW from January 27 to January 31, resulting in more frequent congestion during this period.

In January, the north to south rating of Path 26 fluctuated between 3,000 MW and 2,500 MW. Nearly all of the day-ahead congestion on Path 26 occurred when the line was rated 2,500 MW in the middle of the month and at the end of the month. The highest congestion price observed was $50/MWh at HE1800-2000 on January 14.

**Hour-ahead congestion price spikes on Path 15**

Another noticeable event in January were the price spikes on Path 15 (south-north) on January 11 in the hour-ahead market. Due to a problem with the Los Banos - Midway #2-500 kV line, Path 15 was derated to 2,550 MW in the day-ahead market. Starting from HE1300 on January 11, the line was further derated to less than 1,660 MW, causing significant congestion in the subsequent 12 hours in the hour-ahead market. Hour-ahead congestion prices spiked to as high as $140/MWh during this period.

### Table 3. Interzonal Congestion Frequencies and Prices, January 2004

| | Day-Ahead Market | | | | Hour-ahead Market | | | |
|---|---|---|---|---|---|---|---|---|
| | Percentage of Hours Being Congested (%) | | Average Congestion Price ($/MWh) | | Percentage of Hours Being Congested (%) | | Average Congestion Price ($/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 | 6 | 0 | $5 | | 4 | 0 | $25 | |
| IID-SDGE _BG | 0 | 0 | | | 0 | 2 | | $30 |
| LUGOIPPDC_BG | 0 | 0 | | | 0 | 0 | $30 | |
| MEAD _BG | 6 | 0 | $2 | | 4 | 0 | $24 | |
| N.GILABK4_BG | 0 | 0 | | | 0 | 1 | | $30 |
| NOB _BG | 15 | 0 | $0 | | 5 | 1 | $10 | $36 |
| PALOVRDE _BG | 15 | 0 | $3 | | 7 | 0 | $11 | |
| PARKER _BG | 0 | 0 | | | 0 | 0 | $30 | |
| PATH15 _BG | 21 | 0 | $0 | | 5 | 0 | $26 | |
| PATH26 _BG | 0 | 7 | | $5 | 0 | 2 | | $0 |
| SUMMIT _BG | 0 | 0 | $0 | | 0 | 0 | | |

### Table 4. Inter-zonal Congestion Costs by Path, January 2004

| 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 _BG** | $18 | $0 | $2 | $0 | $19 | $0 | $18 | $2 | $19 |
| **LUGOIPPDC_BG** | $0 | $0 | $1,624 | $0 | $1,624 | $0 | $0 | $1,624 | $1,624 |
| **MEAD _BG** | $4,332 | $0 | $13,076 | $0 | $17,408 | $0 | $4,332 | $13,076 | $17,408 |
| **NOB _BG** | $16,893 | $0 | $0 | $80,242 | $16,893 | $80,242 | $16,893 | $80,242 | $97,136 |
| **PALOVRDE _BG** | $568,559 | $0 | $16,458 | $0 | $585,017 | $0 | $568,559 | $16,458 | $585,017 |
| **PATH15 _BG** | $46,122 | $0 | $33,908 | $0 | $80,030 | $0 | $46,122 | $33,908 | $80,030 |
| **PATH26 _BG** | $0 | $677,170 | $0 | $10 | $0 | $677,181 | $677,170 | $10 | $677,181 |
| **Total** | $635,925 | $677,170 | $65,068 | $80,253 | $700,992 | $757,423 | $1,313,095 | $145,321 | $1,458,416 |

## V. Firm Transmission Rights

**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 were scheduled on a few paths (72% on Eldorado, 78% on IID-SCE, 95% on LOGOIPPDC, 77% on Palo Verde, 100% on Silver Peak in the import direction, and 44% on Path 26). Southern California Edison Company (SCE1) and municipal utilities primarily own the FTRs on these paths.

**Table 5. FTR Scheduling Statistics for January, 2004***

| Direction | Branch Group | MW FTR Auctioned | Avg MW FTR Sch | Max MW FTR Sch | Max Single SC FTR Scheduled | % FTR Schedule - Dir |
|---|---|---|---|---|---|---|
| IMP | COI _BG | 745 | 100 | 450 | 450 | 13% |
| IMP | ELDORADO _BG | 510 | 367 | 410 | 410 | 72% |
| IMP | IID-SCE _BG | 600 | 470 | 480 | 460 | 78% |
| IMP | LUGOIPPDC_BG** | 370 | 352 | 364 | 231 | 95% |
| IMP | LUGOMKTPC_BG** | 247 | 0 | 5 | 5 | 0% |
| IMP | LUGOTMONA_BG** | 167 | 97 | 101 | 52 | 58% |
| IMP | LUGOWSTWG_BG** | 93 | 35 | 46 | 28 | 37% |
| IMP | MEAD _BG | 516 | 24 | 78.01 | 26 | 5% |
| IMP | NOB _BG | 686 | 10 | 76 | 40 | 1% |
| IMP | PALOVRDE _BG | 627 | 484 | 627 | 602 | 77% |
| IMP | SILVERPK _BG | 10 | 10 | 10 | 10 | 100% |
| EXP | LUGOMKTPC_BG | 247 | 3 | 5 | 5 | 1% |
| EXP | NOB _BG | 664 | 31 | 83 | 83 | 5% |
| EXP | PATH26 _BG | 1425 | 627 | 1226 | 560 | 44% |

*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 to ISO operation. They were not released in the primary auction.

**FTR Revenue per Megawatt.** The following table summarizes the FTR revenue collected through January 2004. There is positive FTR revenue for only a few branch groups, namely Mead, NOB (import and export), Palo Verde, and Path 26. The FTR revenues on Palo Verde (import) and Path 26 (north to south) were $289/MW and $324/MWh respectively due to a higher occurrence of congestion on these two paths.

## Table 6. FTR Revenue Per MW ($/MW), January 2004

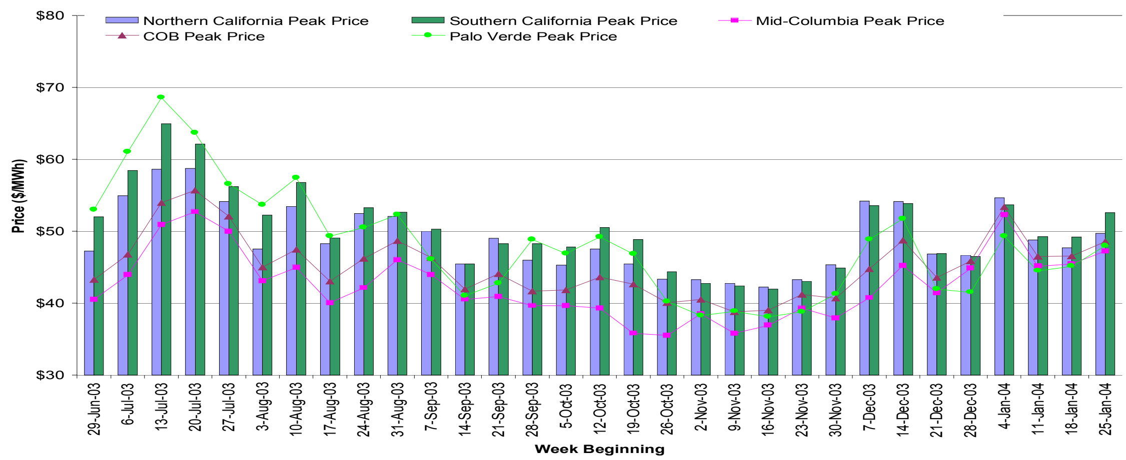
| Direction | Branch Group | Net $/MW FTR Rev | | | | | | | | | | Cumm Net $/MW FTRREV – Imp | Pro Rated NET $/MW FTRREV – Imp* | FTR Auction Price |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | | | |
| IMPORT | BLYTHE | 69 | 0 | 231 | 1422 | 376 | 0 | 0 | 0 | 0 | 0 | 2,097 | 2,517 | 5,460 |
| IMPORT | COI | 723 | 536 | 299 | 138 | 440 | 192 | 352 | 100 | 284 | 0 | 3,065 | 3,678 | 59,484 |
| IMPORT | ELDORADO | 0 | 0 | 1 | 0 | 0 | 268 | 516 | 248 | 576 | 0 | 1,609 | 1,931 | 33,888 |
| IMPORT | LUGOIPPDC** | 272 | 0 | 0 | 5151 | 8 | 0 | 30 | 2 | 0 | 4 | 5,467 | 6,560 | 0 |
| IMPORT | LUGOTMONA** | 0 | 715 | 7 | 0 | 15 | 310 | 461 | 24 | 4 | 0 | 1,537 | 1,844 | 0 |
| IMPORT | LUGOWSTWG** | 3 | 0 | 0 | 0 | 0 | 9 | 0 | 0 | 261 | 0 | 273 | 328 | 0 |
| IMPORT | MEAD | 166 | 0 | 14 | 150 | 85 | 137 | 158 | 4 | 3 | 25 | 742 | 890 | 46,920 |
| IMPORT | NOB | 249 | 203 | 68 | 96 | 118 | 42 | 68 | 5 | 86 | 23 | 958 | 1,149 | 73,470 |
| IMPORT | PALOVRDE | 233 | 15 | 5 | 251 | 355 | 413 | 49 | 249 | 139 | 289 | 1,999 | 2,398 | 88,167 |
| IMPORT | PATH26 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 6 | 1,470 |
| IMPORT | SUMMIT | 108 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 108 | 130 | 2,600 |
| EXPORT | IID-SDGE | 0 | 480 | 0 | 0 | 5651 | 0 | 0 | 0 | 0 | 0 | 6,131 | 7,358 | 364 |
| EXPORT | NOB | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 21 | 111 | 135 | 162 | 5,085 |
| EXPORT | PATH15** | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 6 | 0 |
| EXPORT | PATH26 | 1147 | 1500 | 224 | 780 | 572 | 113 | 1433 | 1 | 41 | 324 | 6,136 | 7,363 | 34,408 |
| EXPORT | SILVERPK | 0 | 0 | 720 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 720 | 864 | 100 |

* We estimate pro-rated 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 the FTR cycle.
** FTRs on these paths were awarded to municipal utilities that converted their lines to ISO operation, and were not released in the primary auction.

## VI. Regional Day Ahead Bilateral Markets

Day ahead prices in the bilateral market were high in the first week of January due to high natural gas prices, but settled closer to December prices. Natural gas prices stabilized below $6/MMBtu. Monthly peak prices were reached on January 6. Average California prices increased from $57.5/MWh on January 5 to $62.50/MWh on January 6 when the high natural gas prices experienced throughout the country had their effect. Between January 8 and January 11, prices descended to monthly average levels; however, on January 12, California prices spiked to the $60/MWh level, again in response to high natural gas prices. The remainder of the month saw prices close to monthly averages, although a slight upward trend continued as more gas was withdrawn from storage and cold weather continued in the east. Average January peak weekday regional day-ahead electricity prices were $49.46/MWh at the California-Oregon Border, $47.66/MWh at Mid-Columbia, $47.97/MWh at Palo Verde, $51.47/MWh in Northern California, and $52.60/MWh in Southern California. The following chart shows weekly average bilateral electricity contract spot prices at regional trading hubs through January.

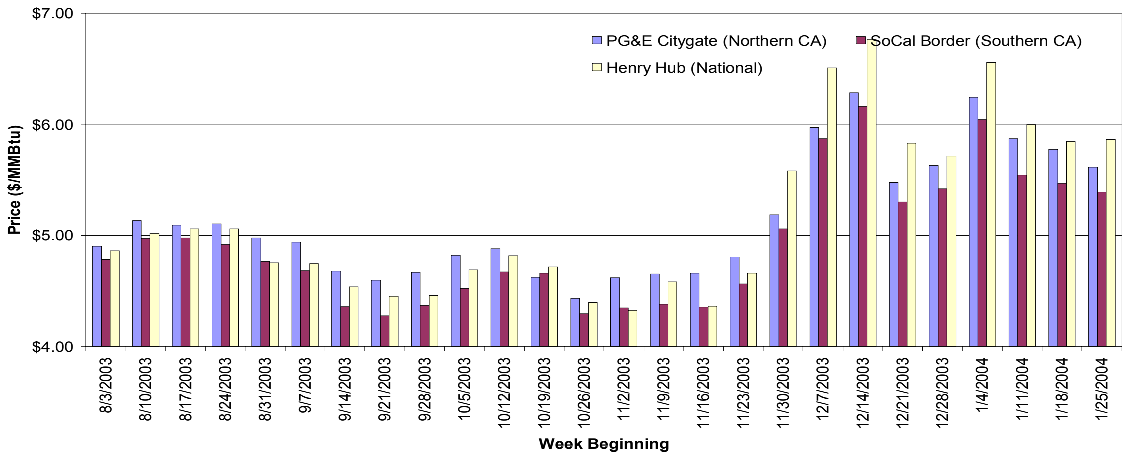
**Figure 14. Weekly Average Day-Ahead Bilateral Contract Electricity Prices**




## VII. Natural Gas Markets

While natural gas prices spiked briefly, January prices were, on average, lower than those in December. Monthly peak prices occurred during the first full week of January when temperatures across the country sharply decreased, most notably in the east. Low temperatures in New York City, for example, decreased from 30.2°F on January 6 to 19.0°F on January 7. During that same time period, Henry Hub peak prices increased from a high of $6.41/MMBtu on January 6 to their monthly high of $7.25/MMBtu on January 7. The east coast's coldest temperatures of January came a few days later, when temperatures decreased from a high of 30.2°F on January 9 to a high of 15.8°F on January 10. During this first week, Henry Hub prices averaged $6.71/MMBtu, while California prices averaged $6.19/MMBtu. The remainder of the month saw moderating temperatures and natural gas prices, although Henry Hub prices reached $6.15/MMBtu on January 20 when east coast temperatures were lower than average for a few days. Average daily gas prices for January were $6.04/MMBtu at Henry Hub, $5.54/MMBtu at Malin, $5.86/MMBtu at PG&E Citygate, and $5.60/MMBtu at Southern California Border Average. Average bid week prices for February were $5.29, $5.23, and $5.52 for SoCal Gas, Malin, and PG&E Citygate, respectively, down 3%, 1%, and 1% from January bid week prices. The following chart shows weekly average gas prices at regional delivery points through January.

**Figure 15. Weekly Average Natural Gas Prices at Regional Delivery Points**




## VIII. Issues under Review

**Insufficiency of Decremental Bids.** In recent months, the ISO has often run out of bids when issuing decremental dispatches in periods when real-time generation exceeds actual load. When this happens, the ISO must resort to decremental out-of-market instructions to balance generation with load. The Market Monitoring Unit (MMU) has conducted an informal analysis to determine the reasons for the lack of sufficient decremental bid volume in the real-time balancing energy market.

The preliminary results of the investigation indicate that the reason for lack of decremental bids is that few units tend to be available to be decremented in these hours. For a generating unit to be decremented it must be capable of having a variable level of output and it must be operating at a level above its minimum operating point. The insufficiency problem occurs most often in early morning hours, between 3:00 and 7:00 a.m. when many units are shut off for the night or are configured to run at minimum output levels. For example, a combined-cycle unit that has two gas turbines and one steam exhaust turbine may be running at that time with only one gas turbine at its minimum operating level. In addition, some units are being held on pursuant to the Must-Offer Obligation. When this is the case, they must also be running at their minimum output levels.

**January 11 Path 15 Derate Market Impact.** Due to a problem with the Gates substation at the southern end of the Los Banos - Midway #2-500 kV line, transfer capability on Path 15 was severely limited causing ISO operators to take significant steps to increase energy production north of Path 15 and reduce energy production south of Path 15 to prevent path overloads. Due to a low volume of decremental SP15 imbalance energy bids, ISO operators had to call several units out-of-market to reduce output in southern California, at the same time generators in northern California had to be dispatched to increase output to keep the system in balance. To estimate the costs of this event, an informal analysis was conducted that compared average real-time imbalance energy costs during the same time period for the previous and next three Sundays and compared those costs to the real-time energy costs incurred on January 11. Due in part to the brief duration of the real-time market impacts, the increased real-time costs were limited to approximately $80,000. Increased out-of-market and RMR costs were estimated to contribute another $64,000 for a total real-time market impact of roughly $144,000. It should be noted that these costs represent only the estimated increased real-time market costs associated with the event and do not include increased in interzonal congestion costs as well as increased costs to scheduling coordinators who had to alter schedules in order to accommodate reduced flows on Path 15.

**SoCal Gas Tariff Modifications before CPUC.** Draft gas tariff proposals before the CPUC filed by Southern California Gas Company pursuant to a Comprehensive Settlement Agreement would extend the potential for daily gas imbalance charges beyond the winter months to year round (see D. 01-12-0189, proposed Rule No. 40 and Schedule No. G-IMB) Daily imbalances in excess of 10% could be subject to a charge equal to 150% of the spot market price if system level imbalances for non-core users (which include gas-fired generators) exceeded a specific threshold. Such changes could, in theory, significantly increase prices in the ISO's real time imbalance market, due to the unpredictability of demand and heavy reliance on gas-fire generation in the ISO for real time imbalance energy market. ISO Management submitted a letter to the CPUC commission expressing concern about this impact such daily imbalance charges could have on prices in the ISO's real time market for electricity, and encouraged the Commission to defer approval of these tariff changes and examine these potential impacts on the electricity market in more detail. A variety of other parties also urged reconsideration of other aspects of the draft gas tariff revisions. A decision on the gas tariff changes originally scheduled for February 11 was deferred until at least February 26, while the Commission considers alternatives.