CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

From: Greg Cook, Manager of Market Monitoring

cc: ISO Officers, ISO Board Assistants

Date: April 15, 2004

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

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

Executive Summary

Approximately 12 days of record high temperatures in March across California had the effect of increasing loads and starting the Spring hydro runoff period early. However, this also reduced the snow pack earlier than usual, from approximately 20 percent above average in February to approximately 20 percent below average by the first week of April, potentially reducing the amount of hydroelectric production available during peak load periods this summer.

High loads and limited supply resulting from seasonal maintenance caused the average real-time incremental energy price to increase to approximately $73 per megawatt-hour (MWh), a rise of 18 percent since February. The tighter market conditions also resulted in less competitive market outcomes as the price-to-cost markup in real-time incremental balancing energy increased in March to approximately 20 percent, roughly twice that in February.

Costs associated with managing intrazonal (within-zone) congestion costs remained high in March, similar to February levels. The San Onofre Nuclear Generating Station (SONGS) Unit 2, which began planned refueling on February 9, remained off-line through March. The loss of this generation south of Los Angeles results in greater flows over the Southwest Power Link (SWPL, a transmission line between Arizona and San Diego), exacerbating congestion at the Miguel substation. This resulted in the second month of high out-of-sequence (OOS) redispatch costs incurred to resolve congestion in real-time. OOS redispatch costs totaled approximately $8.1 million in March, similar to the $8 million incurred in February.

Ancillary service prices increased 22.8 percent on average for all services from February to March 2004, driven by a 422 percent increase in the frequency of bid insufficiency. While the "flattening" of the daily load profile drove down bid insufficiency in February, a tendency toward "peakiness" increased bid insufficiency in March. As daily load peaks increased in intensity, online resources were less able to provide the necessary upward reserves (RU, SP, NS) to meet system requirements. Based upon this relationship and the history of shoulder month bid insufficiency in 2003, ancillary services market bid insufficiency is expected to grow through May.

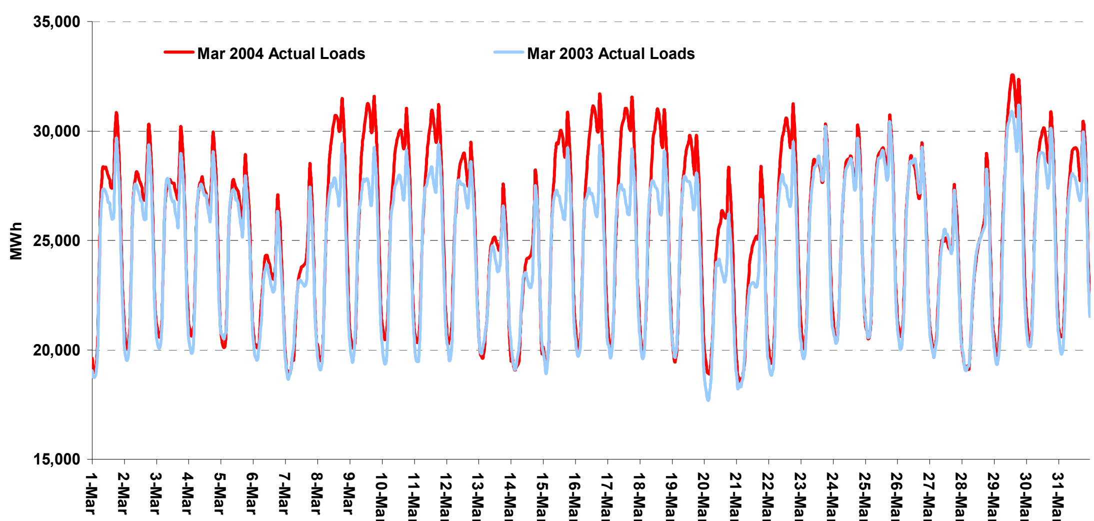
Interzonal Congestion costs were $4.6 million in March, a significant increase from $1.1 million reported in February. Among all congested paths, Path 26 accounted for more than half of the total congestion costs, while Palo Verde accounted for approximately 30 percent. In contrast to February, congestion on Path 26 occurred frequently throughout March due to hotter weather and forced outages of several large generation units, which induced a significant demand for imported power into Southern California. The Palo Verde intertie was also frequently congested as market participants attempted to import power from the southwest region to serve the high Southern California loads.

I. Factors affecting Supply and Demand Conditions

- ***Warm weather caused loads to increase***
- ***Schedules were short of actual load on average***

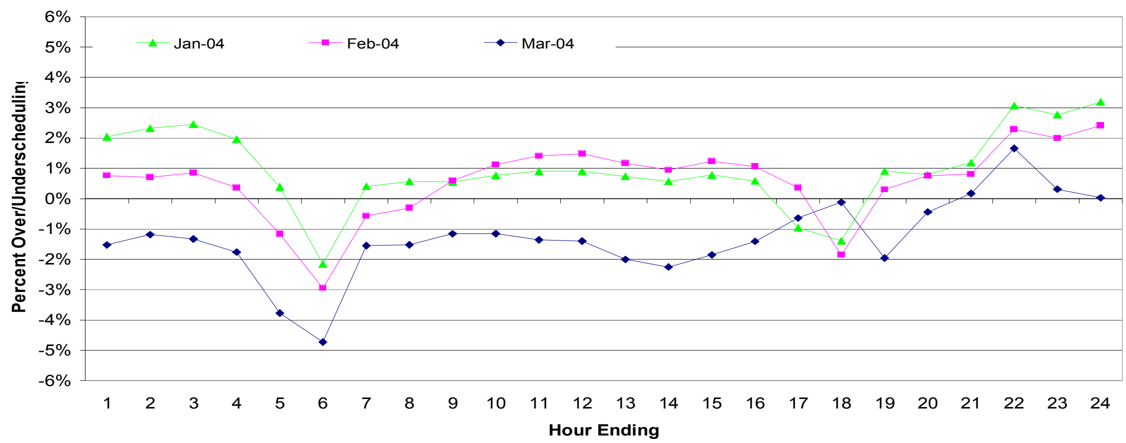
The sudden and warm Spring, which was underway by late February, created unexpectedly high loads in the immediate term. It also melted much of the snow pack, which had been above average, potentially reducing the amount of hydroelectric production available for the peak summer season. Loads averaged 25,407 MW in March 2004, or 4.4 percent above those in March 2003, with a peak load of 32,554 MW on March 29, 2004, between 2:00 and 3:00 p.m., during a declared Stage 1 resource deficiency. This was 4.5 percent above the March 2003 peak; a load level of this magnitude was not seen in the Spring of 2003 until May 20. The following chart shows hourly average loads for March 2003 and 2004.

Figure 1. Hourly Actual Loads, March 2004 v. March 2003



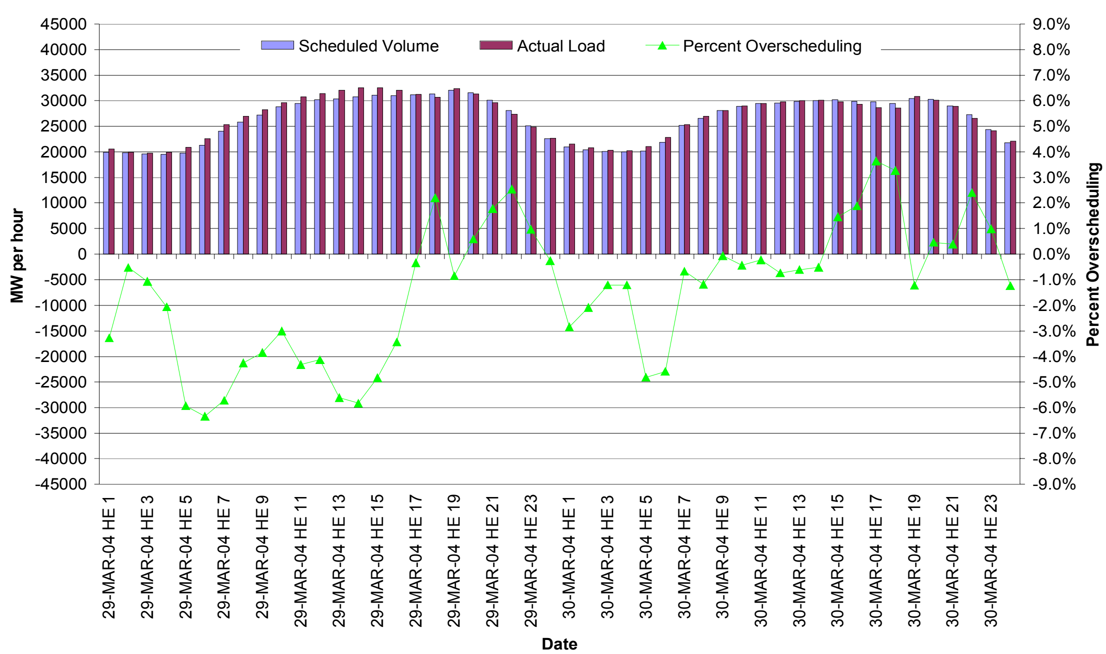
While bulk energy purchased under long-term contracts by the State of California on behalf of load-serving utilities in early 2001 has provided a hedge against the risk of short schedules, peak-hour schedules were still 1.2 percent short of load on average in March, compared to 0.7 percent in excess of load in February. Overall schedules relative to load were the lowest since May 2003. The following chart shows deviations of schedules from actual load for the three months ending March 2004.

Figure 2. Hourly Average Deviations of Schedules from Actual Load, January-March 2004



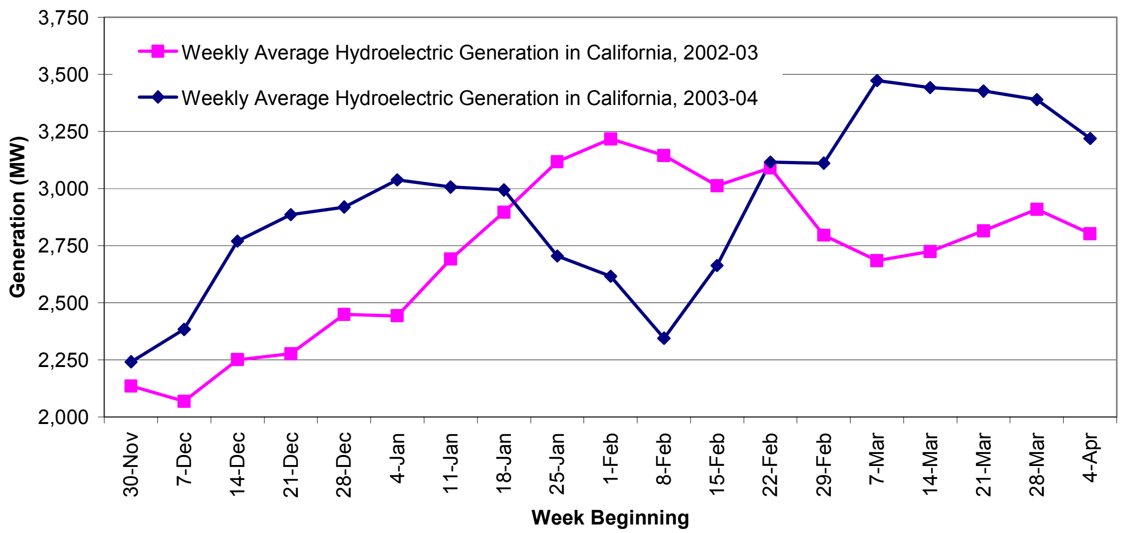
Scheduling was particularly problematic on March 8 and 29, the days of two declared emergencies, on which actual temperatures were approximately 8 to 10 degrees above forecasts across California. Hour-ahead schedules were as much as 5 and 6 percent below actual load on the afternoons of March 8 and 29, respectively. The following chart shows loads and hour-ahead schedules, for March 29 and 30.

Figure 3. Hourly Average Deviations of Schedules from Actual Load, March 29-30, 2004



Spring Runoff. As average temperatures met or exceeded records across California on many days in the month, snow pack levels eroded from the range of 109-117 percent of average in early February, to the range of 70-80 percent of average in most areas in California by the first week of April.[1] Snow pack levels in the Pacific Northwest are similar. Reservoirs have been filling due to the early runoff, some to the point of capacity, and California hydroelectric production has averaged between 3,300 and 3,500 MW in March, significantly higher than in March of last year, as shown below in Figure 4. Some units have begun to spill water during off-peak hours. The following chart compares the 2003 and 2004 approximate weekly average scheduled and real-time hydroelectric generation within California.

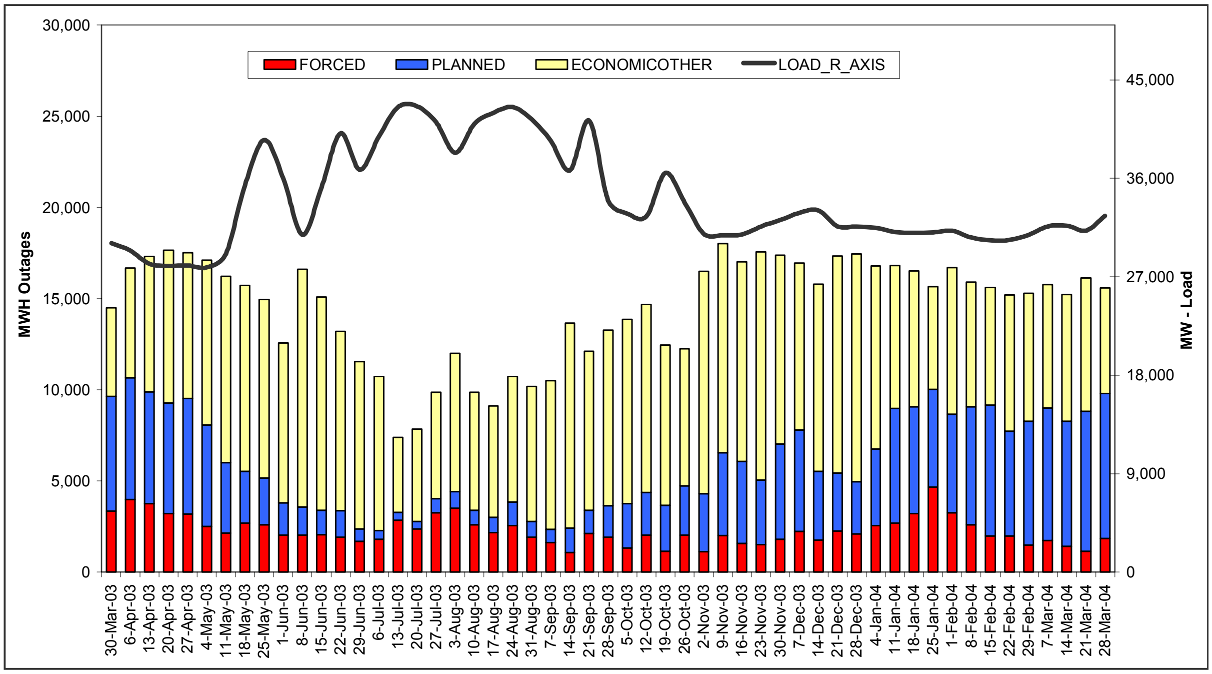
Figure 4. Approximate Weekly Average Hydroelectric Production



Outages. Planned outages increased during the typically high-supply Spring runoff season. The SONGS Unit 2 remained off-line, due to a refueling outage through March, and is expected back in service in early April. A series of forced outages occurred on the morning of March 29, which in part spurred the resource deficiency that afternoon, but many of the affected units returned by the next day. The following chart shows weekly average outages by type through March.

[1] National Conservation Weather Service, *Drought Monitor/Snow pack Weekly Reports,* http://www.wcc.nrcs.usda.gov/water/drought/wdr.pl.

Figure 5. Weekly Average Outages and Daily Peak Load through March



Natural Gas Prices. The cost of natural gas was relatively constant in March, standing in the neighborhood of $5 per million British thermal units (MMBtu), after declining 20 percent between January and February. The Northern California PG&E Citygate price contains a premium of approximately 27 cents above the Southern California Border price, but remains about 12 cents below the Henry Hub national trade price, reflecting regional supply and demand conditions. For more information, please see the section below on natural gas prices.

II. Real-Time Balancing Market Conditions

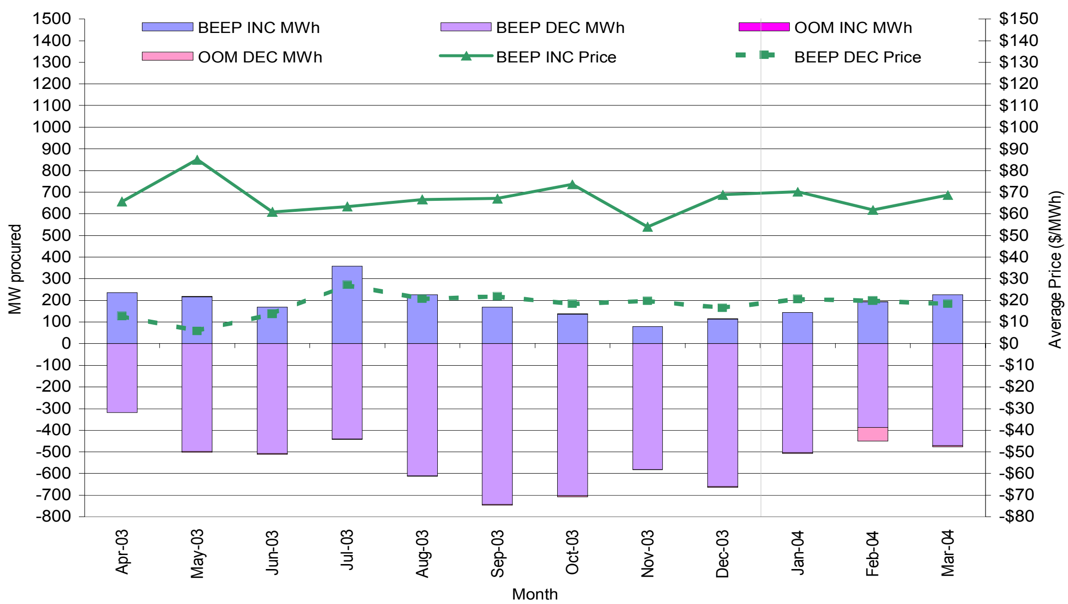
- ***Unexpected high temperatures caused slight increase in incremental volume relative to decremental volume, culminating in March 29 resource deficiency***
- ***Smoother Ramps have helped to decrease frequency of incremental price spikes***
- ***Intrazonal congestion costs totaled $8.1 million***

In light of the high temperatures in California and resultant short energy schedules in March, the ISO's real-time market has seen a decrease in the ratio of decremental to incremental energy, to approximately 2.2 decremental megawatt-hours dispatched for every incremental megawatt-hour dispatched. This ratio peaked in December 2003 at 4.5 to 1,and has declined steadily since that time. Incremental prices, which load pays to generators to increase generation when schedules are not sufficient to meet load, were higher in March, averaging $73.72/MWh, rebounding from a decline in February, with 130 gigawatt-hours (GWh) dispatched. Decremental prices, which generators pay to load for the right to decrease generation when schedules exceed actual load, were similar to those seen in every month since August 2003, averaging $19.39/MWh, with 239 GWh dispatched. The table below shows average prices, total dispatched energy, and average system loads and underscheduling for March. The chart that follows shows monthly trends in real-time prices and volumes through March.

Table 1. Average Prices, Total Dispatched Energy, and Average System Loads and Underscheduling, for March 2004

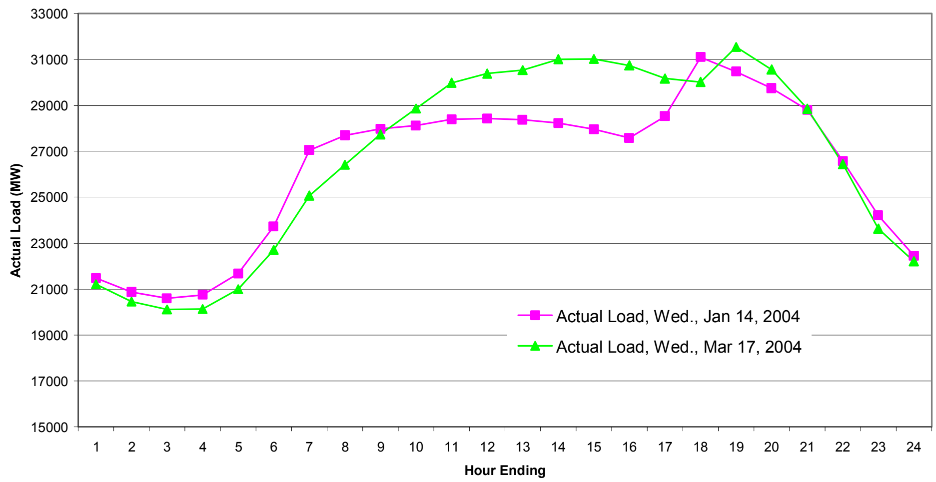
	Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	**Dec**	
Peak	$ 73.72	$ 19.39	27,552 MW
	130 GWh	289 GWh	1.0%
Off-Peak	$ 51.15	$ 15.06	21,116 MW
	38 GWh	66 GWh	1.7%
All Hours	$ 68.62	$ 18.59	25,407 MW
	168 GWh	355 GWh	1.2%

Figure 6. Monthly Average Real-Time Prices and Volumes through March



Smoother Ramps. One effect of the seasonal shift is the smoother ramping periods in the early morning and late afternoon. In January, ramps regularly exceeded 2,500 MW per hour, particularly between 6:00 and 8:00 a.m. (hours ending 7:00 and 8:00), and between 4:00 and 6:00 p.m. (hours ending 17:00 and 18:00). These ramps are smoother in the springtime due to more daylight hours, and milder morning and evening temperatures. With smoother load ramps, ramp planning is less challenging, and real-time price spikes, which occurred almost daily in January, have been relatively infrequent in February and March. That said, the single price spike during the Stage 1 resource deficiency on March 29 was unusually costly, with a significant overall cost impact for the monthly average incremental price. The following chart shows hourly actual loads on Wednesdays January 14 and March 17, 2004.

Figure 7. Actual Loads, Wed., Jan. 14, and Wed., Mar. 17, 2004

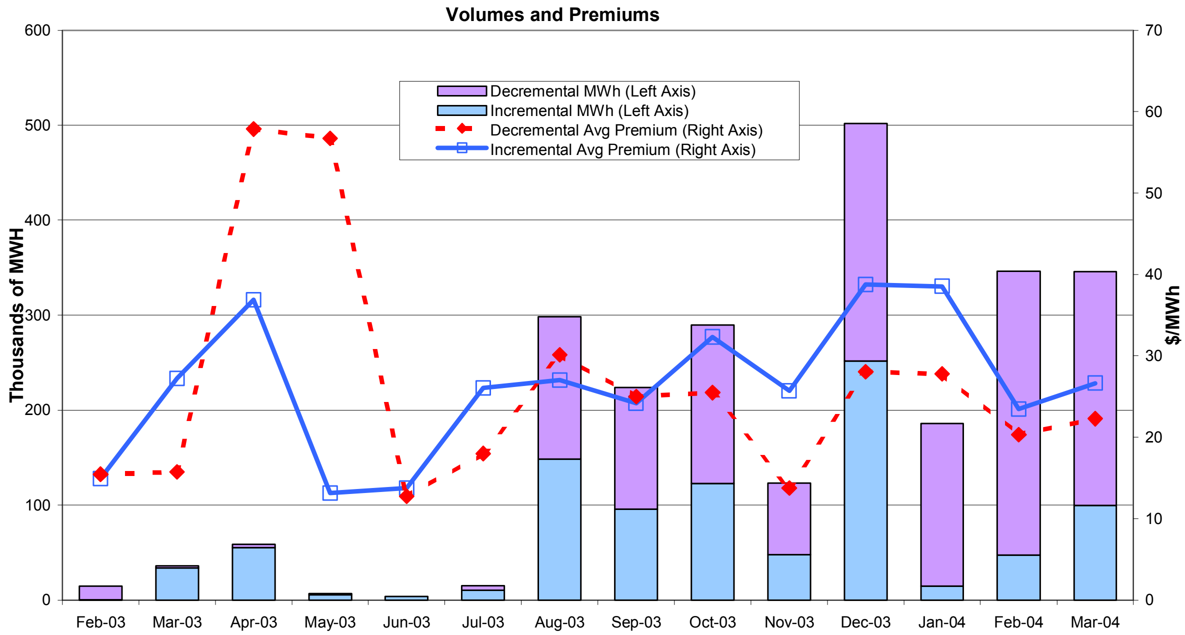


Intrazonal Congestion. Intrazonal congestion costs in March remained high, much the same as in February. There was a slight increase in incremental congestion offset by a decrease in decremental congestion. SONGS Unit 2 has been off-line for refueling since February 9 through March and is expected back in service in early April. The SONGS outage has resulted in increased energy flows over the Southwest Power Link (SWPL) intertie that feeds into the oft-congested Miguel substation. However, these flows were offset somewhat by several Palo Verde outages, mitigating some of the intrazonal congestion at the Miguel Substation. On the incremental side, congestion increased due largely to the upsurge in congestion at the South-of-Lugo substation, although SCIT (Southern California Import Transmission – a technical limit on the import of energy into Southern California) continues to be a significant constraint.

March OOS dispatches resulted in a net cost (re-dispatch premium) of approximately $8.1 million, similar to the $8 million in February. Total OOS dispatch volume was 345 GWh (INC plus DEC) and the average redispatch premium was $23.54/MWh. These figures are shown graphically for recent months in Figure 10.[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 reflects the increased cost of redispatch and any potential mark-up above marginal cost.

Figure 8. Out-of-Sequence Volume and Average Redispatch Premium



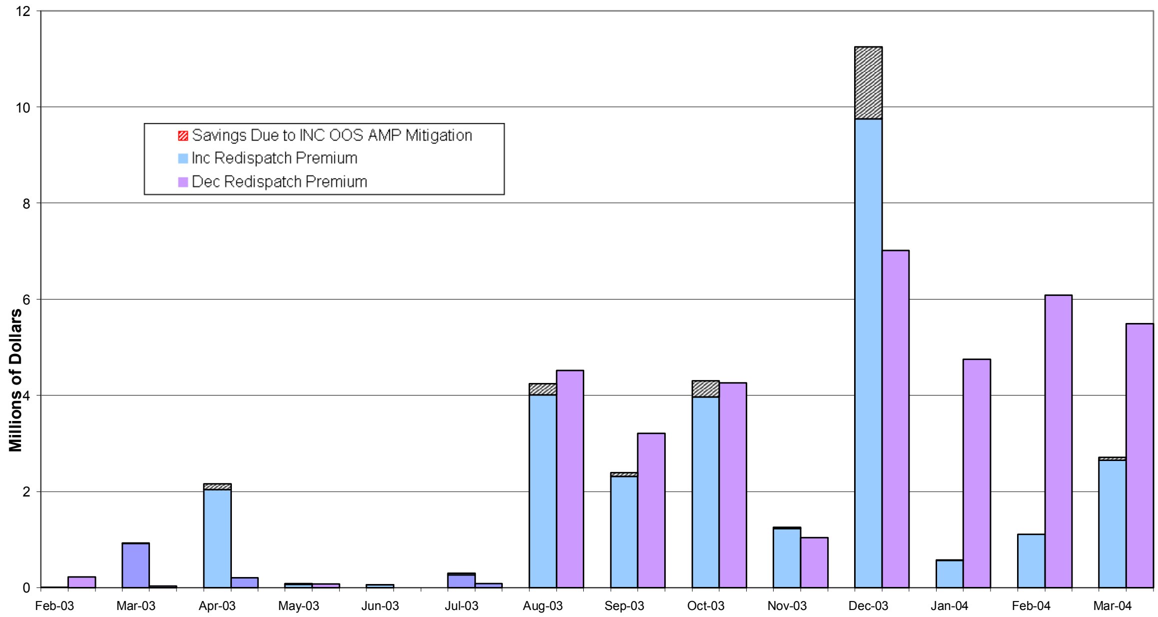
A total of 99,316 MWh of incremental energy was dispatched out of sequence to address intrazonal congestion in February. The average price paid was $57.23/MWh, and the re-dispatch premium in excess of the Market Clearing Price (MCP) was approximately $2.6 million or $26.64/MWh.

There were several reasons for this incremental congestion:

- South of Lugo congestion increased and many incremental dispatches were made to units South of Lugo (i.e., Alamitos, Redondo, Ormond Beach), while units north of Lugo were decremented, (i.e., High Desert);
- 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. At times generation units were incremented both for SCIT and South of Lugo reasons;
- There was real-time Path 26 congestion; and
- There were incidental OOS calls due to transmission line and substation maintenance, in particular maintenance at the Sylmar substation.

Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of $62,049 or 2.3% of the redispatch premium in March. All incremental OOS dispatches are subject to mitigation. Figure 11 shows the re-dispatch premiums for both decremental and incremental congestion as well as the savings due to mitigation of incremental OOS dispatches.

Figure 9. Re-dispatch Premiums and INC OOS Mitigation Savings

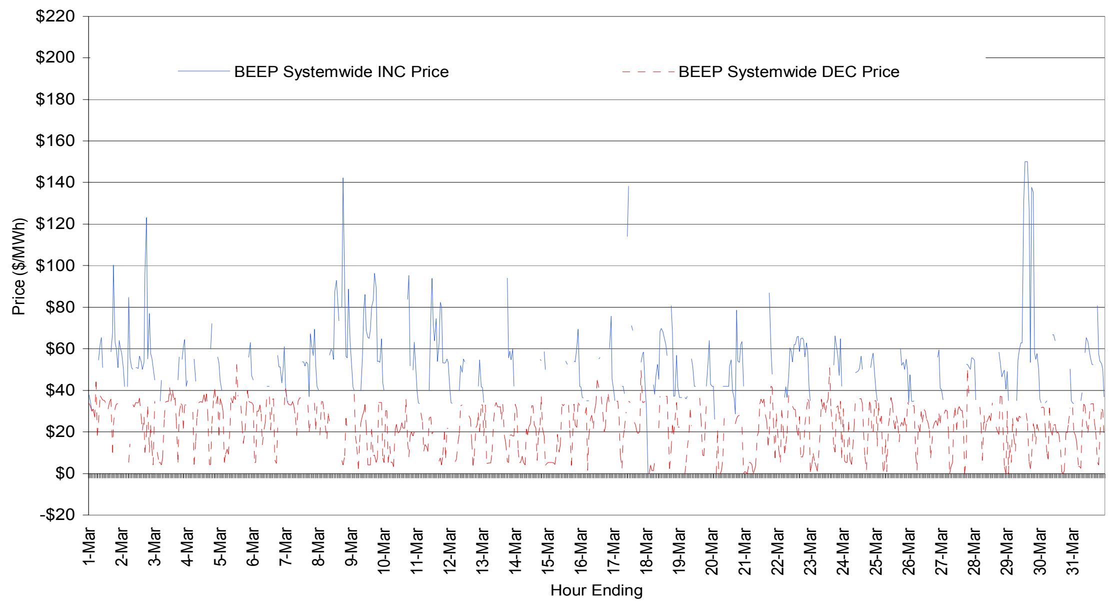


Decremental OOS Dispatches. On the decremental side, a total of 246 GWh was dispatched out of sequence in March. This energy was settled according to the provisions of the Amendment 50 mitigation measures as approved by FERC. The approximate re-dispatch premium in excess of the Market Clearing Price was $5.5 million, or $23.72 MWh. As in previous months, almost all of the decremental activity was due to intrazonal congestion in the San Diego region caused either by the new generation units located in northern Mexico, or by SWPL (South West Power Link) congestion.

AMP Performance and Price Spikes. The systemwide Automatic Mitigation Procedures (AMP) are applied to the incremental balancing market whenever the real-time price is predicted to exceed $91.87/MWh in any zone at 53 minutes prior to the beginning of the hour of operation. The predicted price was $150/MWh on March 8, in Hour Ending 17:00 (between 4:00 and 5:00 p.m.). However, no incremental energy was dispatched in this hour. The real-time hourly average INC price exceeded $100/MWh in five instances in March, however AMP was not applied as the predicted price under the price screen was not above $91.87/MWh in any of these instances.

Two major grid events occurred in March. On March 8, a transmission emergency was declared by the ISO due to a path overload on Path 26. On March 29, the ISO declared a Stage 1 Emergency due to a resource deficiency in Southern California. While both events, and the March 8 event in particular, had serious reliability consequences, only the March 29 deficiency had a significant impact on wholesale electricity prices. The following chart shows hourly average prices in March; the discussion below highlights spikes of interest.

Figure 10. Hourly Average Real-Time Balancing Energy Prices, March 2004



On March 2, the real-time incremental price within SP15 ranged from $123.27 to $123.29/MWh between 5:50 and 7:00 p.m., as all resources that submitted supplemental energy bids were dispatched. At this time, southbound congestion on Path 26 limited the use of less expensive resources in Northern California to supply load in Southern California. Meanwhile, the ISO made out-of-sequence decremental calls within Southern California to work around congestion at the Miguel Substation.

On March 8, the SP15 incremental price ranged from $110.86 to $144.27 between 6:10 and 7:10 p.m., during a transmission emergency caused by an overload of the Path 26 intertie. At this time, an energy shortage in Southern California resulted in load shedding of about 50 MW of non-firm and 250 MW of firm load for about 20-minutes within SP15. The shortage was resolved through the arrangement of out-of-market energy from an entity that does not typically participate in the ISO's markets. The $144.27/MWh was set by a bid from a participating load. Further details can be found at http://www.caiso.com/docs/09003a6080/2e/9b/09003a60802e9b8d.pdf.

On March 9, a peaking unit set the NP15/ZP26 incremental price at $125.86/MWh between 4:10 and 5:00 p.m., as four thermal units at a single plant within the congestion region tripped out due to a malfunction. In this hour, one unit that was awarded a dispatch had bid in a manner that would have failed the AMP Conduct Test had the hour-ahead predicted price exceeded $91.87/MWh (the so-called "Price Screen Test"); however, the portion of the bid in violation of the conduct threshold was not the portion of the bid that was awarded a dispatch.

On March 17, the systemwide incremental price was set at $138/MWh, between 10:40 a.m. and 12:00 p.m., by a thermal unit in NP15 with a reference level of $121.19/MWh, and a marginal cost estimated to be in the range of $50 to $60/MWh. This spike occurred following a forced outage of a large thermal unit within NP15 during a reserve deficiency. In response, the ISO revoked two waivers to the Must-Offer Obligation to increase generation.

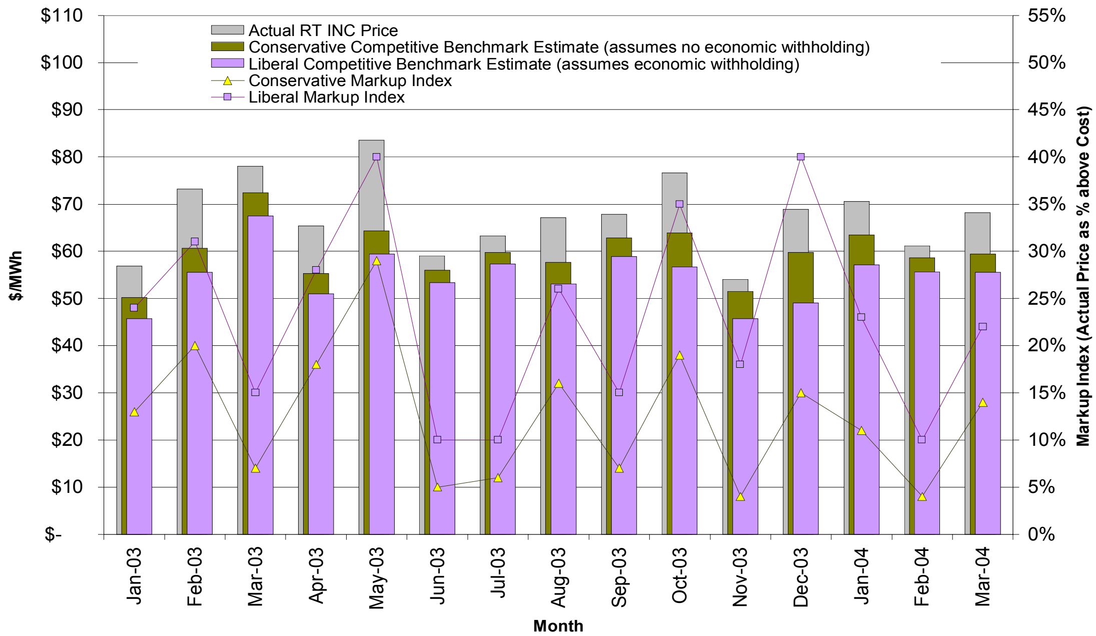
On March 29, the SP15 real-time price was $110.86/MWh between 12:00 and 12:30 p.m., set by a thermal unit with a reference level of $104.24/MWh and a marginal cost estimated at $39.85/MWh. The price then increased to $150/MWh, where it stood until 4:30 p.m. The $150 price was set by a very high-cost thermal unit with a reference level of $134.89/MWh and a marginal cost of approximately $117.66/MWh. The ISO declared a Stage 1 generation emergency beginning at 1:54 p.m. On this day, the actual temperature across California was approximately ten degrees above forecast, resulting in insufficient forward procurement of energy. Meanwhile, several units were either derated due to high temperatures or tripped off in their efforts to respond to high prices. The total loss of resources was approximately 770 MW. The 4½ -hour price spike cumulatively accounted for nearly a quarter of the total estimated costs attributed to the monthly markup above competitive levels, with the markup costs above competitive levels as high as $91,173 between 1:00 and 2:00 p.m. Zonal incremental procurement averaged 2,172 MW, peaking at 2,320 MW between 12:50 and 1:00 p.m. This spike accounted for 5.8 percent of the total dispatched incremental volume and 12.4 percent of the total cost of incremental energy for the month of March.

Market Competitiveness. The real-time price-to-cost markup is an indicator of the competitiveness of the real-time market. The Department of Market Analysis calculates this index as a comparison of the actual incremental market-clearing price to an estimated competitive benchmark price. As discussed in the Market Analysis Report dated February 19, 2004, the Department of Market Analysis now reports two indices[3] 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, it assumes that 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 by substituting estimated marginal cost-based bids for high-priced bids. This produces a lower estimate of the competitive price and a more liberal (higher) estimate of potential markup.

The price-to-cost markup in real-time incremental balancing energy was higher in March, ranging between 14 and 22 percent for the two indices, compared to the range of 4 to 10 percent in February. The ten highest-markup hours accounted for approximately 25 percent of the monthly total; approximately six of these hours were during the Stage 1 Emergency on March 29. Figure 11 shows the two volume-weighted average estimates of competitive price vs. the actual volume-weighted average market-clearing prices for the 15 months ending in February.

[3] 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 a small portion of total load-serving energy in March, care must be taken in drawing conclusions from the real-time markup index to the market as a whole.

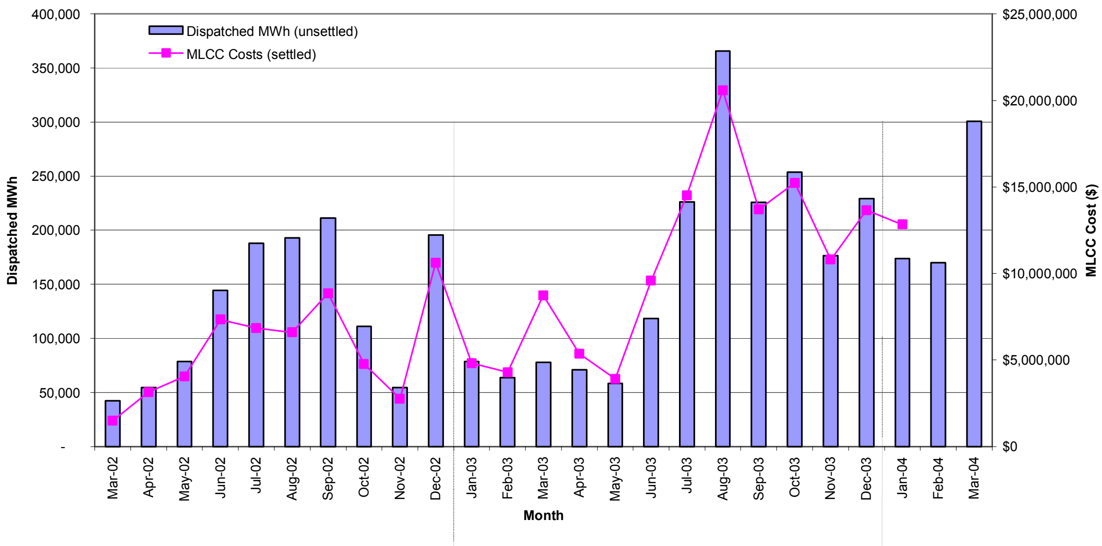
Figure 11. Range of Price-to-Cost Markup in Real-Time Energy through March 2004



Minimum Load Cost Compensation. The Federal Energy Regulatory Commission directed in its June 19, 2001 Order, and upheld in later Orders, that all participating generation in the ISO Control Area must offer all available capacity into an ISO market (the "Must-Offer Obligation"). The Commission then approved a process by which units may apply to the ISO for waivers from the Must-Offer Obligation when not needed for reliability. In the event such a waiver is denied, the ISO will compensate the denied units their minimum-load operating costs, based upon a current gas price index.

Capacity averaging 250, 244, and 404 MW in January, February, and March, respectively, was denied applications for waiver to the Must-Offer Obligation and held on minimum load. Most units were held on-line to support intrazonal congestion mitigation. The following chart shows total MWh held on in each month through March, and settled compensated costs for must-offer resources through January (the most recent period for which data are available).

Figure 12. MWh Held On pursuant to Must-Offer Order through January, And Total Minimum-Load Cost Compensation through March



III. Ancillary Services Markets

- ***Prices increased 22.8% on average for all services while overall demand decreased by 1.5% from February to March 2004.***
- ***Frequency of bid insufficiency increased by 422% from February to March 2004.***

Market Prices. Market prices increased in the ancillary services markets by 22.8 percent from February to March 2004. Overall demand decreased 1.5 percent in March, while overall supply increased by 1.1 percent. The majority of the increase in average prices was caused by an increase in the spinning reserves (SP) market. The decrease in demand for regulation up (RU) drove the overall decline in demand.

Table 2. Average Ancillary Service Requirements and Prices

	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Feb 04	391	406	731	710	$ 19.09	$ 11.13	$ 4.82	$ 1.39
Mar 04	366	409	722	705	$ 21.53	$ 12.44	$ 7.81	$ 1.87

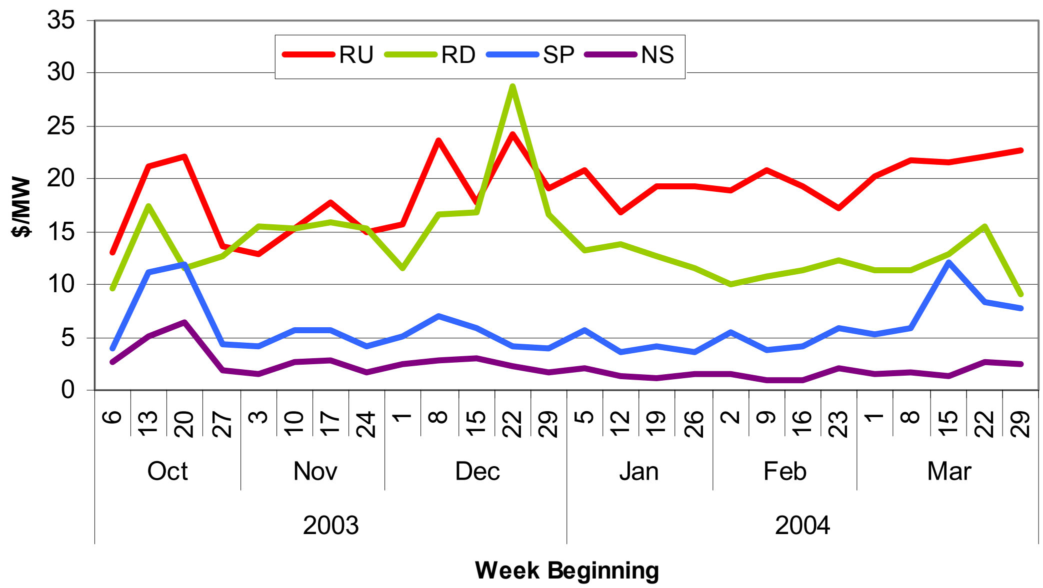
On several occasions in February, energy dispatches to Reliability Must-Run (RMR) units curtailed capacity procured in the day-ahead RU market. To compensate for this curtailment, procurement was increased in the hour-ahead (HA) market. This caused February demand for RU to be overstated. The decline in demand for RU from February to March 2004 was artificial as it indicated a restoration to more usual procurement patterns.

Prices in the SP markets were 62 percent greater in March than in February. This increase was driven by the 478-percent increase in SP bid insufficiency. Furthermore, there were three major pricing events that affected average SP prices during March. These events occurred on March 18, 19, and 28. Each of these pricing events was coincident with insufficient SP bids. Resources that do not often participate in the SP markets set prices ranging from $74 to 84/MW for several hours on each of these days. The impact of pricing events during the third week of March is evident in the chart below of weekly average market prices.

Prices in the RU, regulation down (RD) and non-spinning reserves (NS) markets also increased in response to increasing bid insufficiency and declining supply in the regulation markets.

The Transmission Emergency of March 8th, 2004 and the Stage 1 Emergency of March 29th, 2004 had minimal impact on ancillary service prices. These events were, however, coincident with severe bid insufficiency.

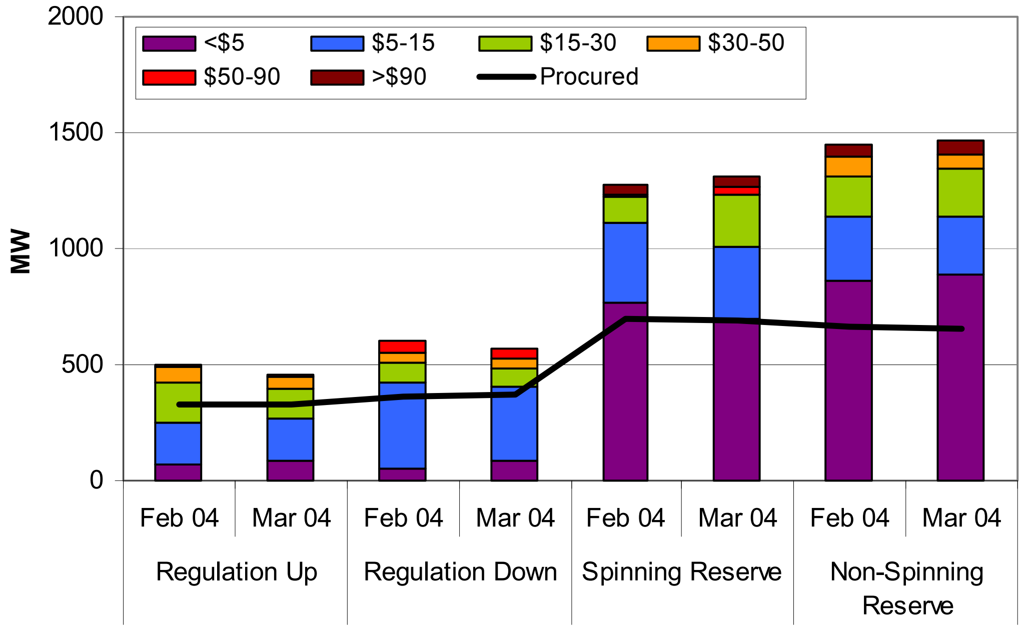
Figure 13. Weekly Weighted Average A/S Prices through March



Ancillary Service Market Supply. Market supply was characterized by an increase in the frequency of bid insufficiency. Supply during peak periods also declined under increasing demand for energy related to unseasonably warm weather.

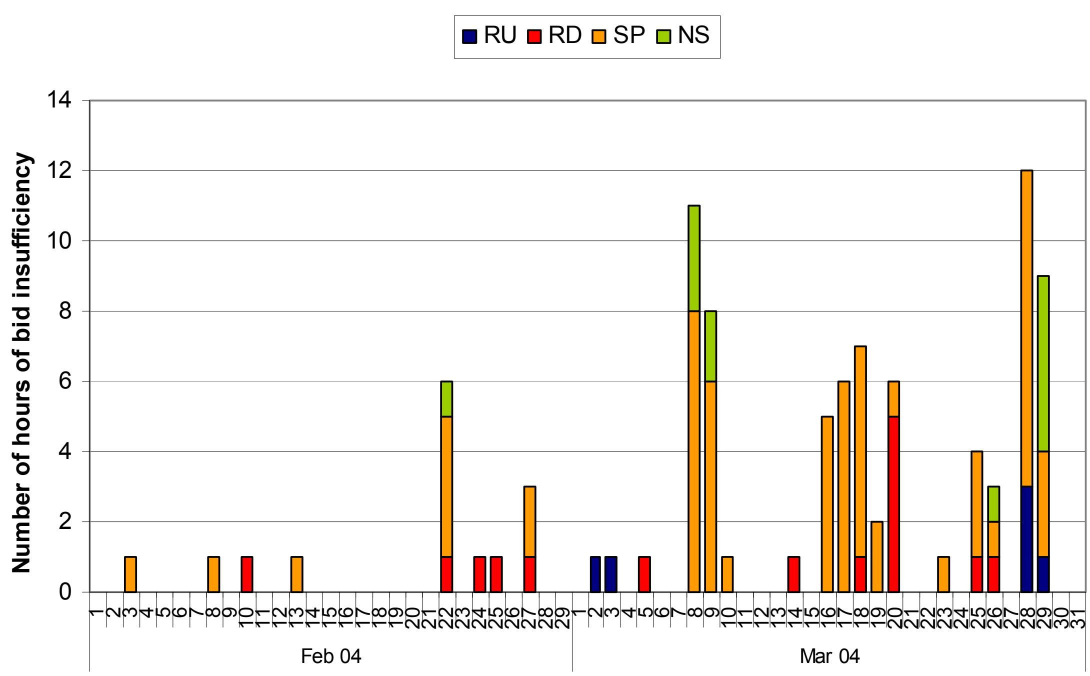
The following chart shows the impact of the overall supply picture on ancillary service prices. Bid composition for the RU, RD and SP favored slightly higher prices than February. Bid composition in NS favored similar prices to February.

Figure 14. A/S Bid Volume by Price Bin through March



Bid insufficiency increased by 422 percent between February and March. Just as the "flattening" of the daily load profile drove declining bid insufficiency in February, a tendency toward "peakiness" drove increasing bid insufficiency. As daily load peaks increased in intensity, online resources were less able to provide the necessary upward reserves (RU, SP, NS) to meet system requirements. Based on this relationship and the history of shoulder month bid insufficiency in 2003, bid insufficiency is expected to grow through May.

Figure 15. Frequency of Bid Insufficiency, February through March



IV. Interzonal Congestion Markets

- ***Significant congestion reported on Path 26 and Palo Verde in March***

Interzonal Congestion costs were $4.6 million in March, a significant increase from $1.1 million reported in February. Among all congested paths, Path 26 and Palo Verde incurred about $2.5 million and $1.4 million in congestion cost. The other paths had significant positive congestion costs are COI, Eldorado, and Pacific DC Inter-ties (NOB).

In contrast to February, congestion on Path 26 occurred frequently throughout March. Path 26 was congested 29 percent of the time in the north to south direction. On several different occasions on March 1, 9, and 22, the day-ahead congestion prices reached or exceeded $50/MWh. The unseasonably warm weather and the forced outage of several large generation units induced a significant demand for power import into Southern California, which in turn caused congestion on major paths into SP15. On March 9, 10, and from 21 to the end of month, the Path 26 was further derated from 3,000 MW to 2,500 MW in the north to south direction due to area resource maintenance. These derates exacerbated the congestion problem.

Meanwhile, Palo Verde was also frequently congested, especially in the middle and later part of the month. Market participants attempted to import power from the southwest to serve the southern California load. The submitted initial day-ahead schedules exceeded the import capacity of the line. For most of the month, Palo Verde had an import capacity of 2,823 MW. Day-ahead congestion prices were modest, and the highest congestion price reported in the month was $10/MWh, on March 13, when the line was derated to 1,805 MW.

Hour-ahead congestion price spikes During the Stage I Emergency period

Hour-ahead congestion price spikes occurred on March 29 during the ISO declared the Stage 1 Emergency. Hour-ahead congestion prices reached $245/MWh on Path 26 (north to south), $235/MWh on Palo Verde (import), $245/MWh on Mead (import), and $309/MWh on El Dorado between 3 p.m. and 4 p.m., while congestion prices were modest in the adjacent hours.

Table 3. Interzonal Congestion Frequencies and Prices, March 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	0	0	$0		0	0	$0	
COI	8	0	$2		11	0	$7	
ELDORADO	2	0	$25		3	0	$40	
LUGOTMONA	9	0	$2		0	0	$30	
MEAD	0	0			1	0	$66	
NOB	19	0	$1		10	0	$6	
PALOVRDE	26	0	$4		9	0	$18	
PATH 15	0	0	$0		0	0	$10	
PATH 26	0	29		$5	0	17		$7
SUMMIT	1	0	$0		0	0	$0	

Table 4. Interzonal Congestion Costs, March 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	
CASCADE	$0	$0	$0	$0	$0	$0	$0	$0	$0
COI	$167,437	$0	$5,097	$0	$172,534	$0	$167,437	$5,097	$172,534
ELDORADO	$257,434	$0	$17,003	$0	$274,437	$0	$257,434	$17,003	$274,437
LUGOTMONA	$22,450	$0	$1	$0	$22,451	$0	$22,450	$1	$22,451
MEAD	$0	$0	$42,384	$0	$42,384	$0	$0	$42,384	$42,384
NOB	$143,730	$0	$19,551	$0	$163,281	$0	$143,730	$19,551	$163,281
PALOVRDE	$1,393,677	$0	$8,448	$0	$1,402,125	$0	$1,393,677	$8,448	$1,402,125
PATH 15	$0	$0	$4	$0	$4	$0	$0	$4	$4
PATH 26	$0	$2,488,862	$0	$36,818	$0	$2,525,680	$2,488,862	$36,818	$2,525,680
SUMMIT	$18	$0	$0	$0	$18	$0	$18	$0	$18
Total	$1,984,747	$2,488,862	$92,487	$36,818	$2,077,234	$2,525,680	$4,473,609	$129,305	$4,602,913

V. Firm Transmission Rights Markets

FTR scheduling. FTRs can be used to hedge against high congestion price 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% on El Dorado, 69% on IID-SCE, 46% on Lugo-IPP (DC), 49% on Lugo-Mona, 76% on Palo Verde, 94% on Silver Peak in the import direction, and 51% on Path 26). FTRs of those paths are mainly owned by Southern California Edison Company (SCE1) and other municipal utilities.

Table 5. FTR Scheduling Statistics for March, 2004*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
IMP	BLYTHE	167	4	167	167	2%
IMP	COI	745	128	500	500	17%
IMP	ELDORADO	510	358	410	410	70%
IMP	IID-SCE	600	416	429	409	69%
IMP	LUGOIPPDC **	370	171	364	231	46%
IMP	LUGOMKTPC **	247	1	30	30	0%
IMP	LUGOTMONA **	167	82	127	75	49%
IMP	LUGOWSTWG **	93	34	44	28	37%
IMP	MEAD	516	31	82	30	6%
IMP	NOB	686	49	151	100	7%
IMP	PALOVRDE	627	478	627	602	76%
IMP	SILVERPK	10	9	10	10	94%
EXP	LUGOMKTPC **	247	3	3	3	1%
EXP	LUGOTMONA **	543	3	50	50	1%
EXP	NOB	664	30	83	83	5%
EXP	PATH 26	1425	727	1291	560	51%

*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 there were not released in the primary auction.

FTR Revenue per Megawatt. The FTRs auctioned in 2003 expired on March 31, 2004. From April 1, 2004, a new FTR cycle begins. The following table summarizes the monthly and total revenue for each FTR auctioned at the beginning of 2003. For most FTRs, the cumulative revenue was significantly less than the purchase price. This is not surprising in that the transmission owners purchased most FTRs on the important paths, and their aggressive bidding behavior at the time of auction resulted in an auction clearing prices that likely overstated the real market values of FTRs. For instance, the FTR auction-clearing price on Palo Verde was $88,167/MW, while its cumulative revenue by the end of FTR season was only $2,988/MW.

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

Direction	Branch Group	Net $/MW FTR Rev												Cumm Net $/MW FTRREV – Imp	FTR Auction Price
		Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar		
IMPORT	BLYTHE	69	0	231	1422	376	0	0	0	0	0	0	0	2,097	5,460
IMPORT	CFE	0	0	0	0	0	0	0	0	0	0	4	0	4	745
IMPORT	COI	723	536	299	138	440	192	352	100	284	0	256	120	3,441	19,828
IMPORT	ELDORADO	0	0	1	0	0	268	516	248	576	0	5	314	1,928	16,944
IMPORT	LUGOIPPDC**	272	0	0	5151	8	0	30	2	0	4	15	0	5,482	N/A
IMPORT	LUGOTMONA**	0	715	7	0	15	310	461	24	4	0	0	134	1,671	N/A
IMPORT	LUGOWSTWG**	3	0	0	0	0	9	0	0	261	0	0	0	273	N/A
IMPORT	MEAD	166	0	14	150	85	137	158	4	3	25	216	63	1,021	7,820
IMPORT	NOB	249	203	68	96	118	42	68	5	86	23	25	218	1,201	12,245
IMPORT	PALOVRDE	233	15	5	251	355	413	49	249	139	289	270	720	2,988	88,167
S-N	PATH 26	0	0	5	0	0	0	0	0	0	0	0	0	5	245
IMPORT	SUMMIT	108	0	0	0	0	0	0	0	0	0	0	0	109	650
EXPORT	IID-SDGE	0	480	0	0	5651	0	0	0	0	0	390	0	6,521	182
EXPORT	NOB	0	0	0	0	0	0	3	0	21	111	0	0	135	565
N-S	PATH 15 **	0	5	0	0	0	0	0	0	0	0	0	0	5	N/A
N-S	PATH 26	1147	1500	224	780	572	113	1433	1	41	324	20	1112	7,268	8,602
EXPORT	SILVERPK	0	0	720	0	0	0	0	0	0	0	0	0	720	100

*Pro-rated 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.

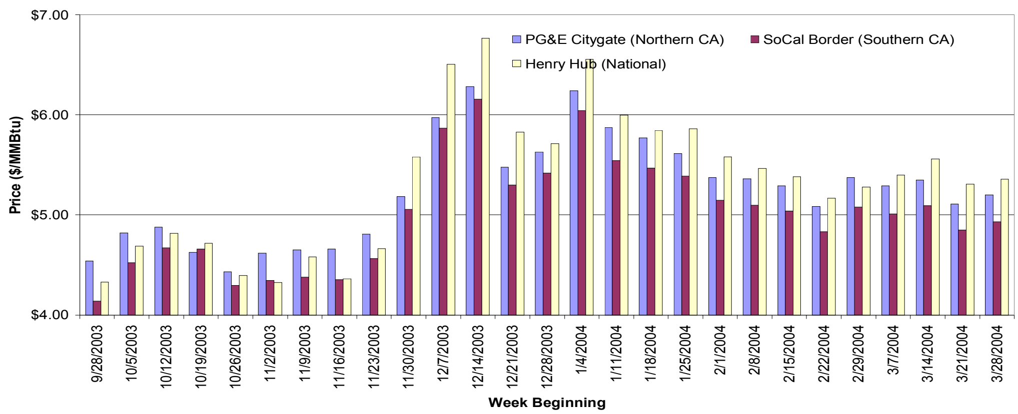
VI. Natural Gas Markets

Mild weather in California through much of March left natural gas prices at average levels similar to or lower than those in February. California prices were highest in the first week of March, while Henry Hub prices were highest during the third week of March, due to inclement weather in the East and the Midwest. These prices were not substantially higher than the average prices for periods outside those weeks: the average price at Henry Hub during the third week of March was only $0.22/MMBtu higher than the average price outside that week, and the average California price during the first week of March was only $0.14/MMBtu higher than the average price outside that week. The last week of March saw a substantial increase in natural gas prices throughout the U.S. as word of early injections of natural gas into suppliers' storages resulted in higher demand and prices.

Average daily gas prices for March were $5.39/MMBtu at Henry Hub, $4.90/MMBtu at Malin, $5.20/MMBtu at PG&E Citygate, and $5.00/MMBtu at Southern California Border Average. Average bid week prices for April were $4.87, $4.76, and $5.20/MMBtu for SoCal Gas, Malin, and

PG&E Citygate, respectively, up 3%, 3%, and 4% from March bid week prices. The following chart shows weekly average gas prices at regional delivery points through March.

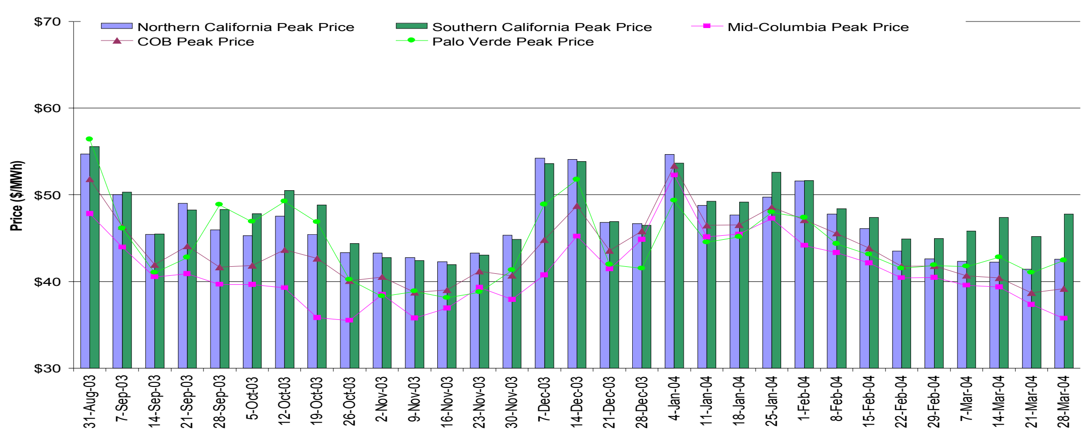
Figure 16. Weekly Average Natural Gas Prices



VII. Bilateral Electricity Spot Markets

Day-ahead electricity prices, while essentially flat (reflecting the low variance in natural gas prices), were lower than electricity prices in February. Southern California prices were consistently above Northern California prices, owing to ongoing transmission and resource constraints in California. Palo Verde prices reached a localized peak for deliveries on March 9 and March 18, with above normal temperatures in the Southwest. The Southern California price was $49.00/MWh when the ISO declared a Stage 1 Emergency on March 29, near the Southern California monthly peak price of $49.50/MWh. Average February peak weekday regional day-ahead electricity prices were $40.40/MWh at the California-Oregon Border, $38.75/MWh at Mid-Columbia, $42.68/MWh at Palo Verde, $42.88/MWh in Northern California, and $46.99/MWh in Southern California. The following chart shows day-ahead bilateral spot market prices through March.

Figure 17. Weekly Average Day-Ahead Bilateral Electric Spot Market Prices



Issues under Review

Decremental Energy Prices at or around $0/MWh. The ISO continues to receive schedules that exceed total actual load in many periods, particularly during the late evening and early morning hours. In response, the ISO must instruct resources to decrement generation, by awarding bids in the real-time Balancing Energy Ex-Post Price auction market (the "BEEP Stack"). In March, one large hydroelectric resource in particular that serves load in Southern California has been decremented to the point of spilling (diverting water over the edge of a dam's spillway, rather than through its turbines, to avoid generating electricity), primarily in off-peak hours. To signal its reluctance to spill water, this unit has bid its decremental energy at a price near $0/MWh; that is, the unit is indicating that it receives no value from avoiding generation. This unit was either marginal or inframarginal in 204 of 3,454 pricing intervals (5.9 percent) in which decremental energy was dispatched in March, or a cumulative total of 34 hours. In the vast majority of those 204 intervals, the unit was marginal and also provided the last available bid in the decremental stack. In the remainder, the unit was inframarginal and the price was set by the next (and final) bid in the decremental stack, at a price between -$0.50/MWh and $0/MWh. The underlying causes of the exhausting of the decremental bid stack remains under investigation; however, this appears to be a symptom of the persistent lack of available decremental resources, as reported in recent Market Analysis Reports.

Must-Offer Waiver Process Redesign. The ISO is concluding the current round of market issue and design forums, both internal and via stakeholder meetings, to address Must-offer Waiver Denial procedures and compensation. The ISO is currently finishing the draft filing on such to be filed with FERC later in April. This filing contains provisions to allow units constrained on from waiver denial to participate in the Day-Ahead and Hour-Ahead A/S markets without rescission of minimum load compensation. In this filing, the ISO also proposed the use of economic criteria in selecting units to commit through waiver denial. ISO Staff delivered a presentation to FERC Staff detailing the proposal on April 1. The issue of whether or not units constrained on from waiver denial should receive compensation for their unloaded capacity will be addressed through subsequent stakeholder process and filing with FERC.

Market Surveillance Committee (MSC). The MSC reelected Prof. Frank Wolak to a one-year term as Chairman of the MSC.

Transmission Methodology. DMA completed the second stakeholder working group conference and provided additional details on the methodology, assumptions, and initial results. DMA is finishing the 2008 cost-based case, and is developing the 2013 cost-based case, the two cases forecasting market prices instead of marginal costs, and the sensitivity studies. A final stakeholder working group conference will be held on Wednesday, April 28.