California Independent
System Operator

CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers

Date: March 25, 2005

Re: **Market Analysis Report for February 2005**

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

Executive Summary

Load growth slowed in January and February 2005, as key growth indices ranged between 1.5 and 2.2 percent in February, when adjusting for the exit of Western Area Power Administration load.

The CAISO has incremented balancing energy in many hours in real-time since January, which could be due in part to some load-serving entities scheduling short of actual load to exploit real-time prices that have generally been below day-ahead prices in recent weeks. This reverses a 2004 trend of over-scheduling that had caused the CAISO to decrement in real time. The volumes of real-time import bids and dispatches have increased substantially since the implementation of RTMA, which clears overlapping incremental (import) and decremental (export) real-time bids. These pre-dispatched bids are then paid either the market clearing price, or their bid price, whichever is better. This "bid-or-better" guarantee has raised bidding and settlement issues that are currently being analyzed by the CAISO.

Intra-zonal congestion costs totaled approximately $3.1 million in February, their lowest level since July 2004. The bulk of the costs continue to be decremental commitments to manage congestion at the Miguel Substation east of San Diego, and to a lesser extent, at the Cortina Substation in Northern California which is undergoing planned maintenance.

Decreased bid insufficiency resulted in lower ancillary service market prices in February compared to January 2005, with the exception of regulation down where there was a significant decrease in bid insufficiency compared to January.

A persistent series of fall and winter storms have brought record snowpacks and precipitation to California and the Southwest, and above-average snowpacks to some areas in Canada. Basin snowpacks in the Sierras of California are in excess of 150 percent of average. In contrast, snowpack and seasonal precipitation in the Pacific Northwestern U.S. is well below average with many basins in Oregon and Washington reporting less than 50 percent of average. As of February 1, most basins in the Pacific Northwest are forecast to receive below average spring and summer stream flows while California and Southwestern basins are forecast to receive above average spring and summer stream flows.

II. Trends Affecting Energy Demand and Supply

- *Load growth slowing*
- *Forward prices higher*
- *Snowpack strong in California but weak in Pacific Northwestern U.S.*

Loads and Under-scheduling. Load growth appears to have slowed since January 2005. Through December 2004, the ISO had seen a two-year trend of approximately 4% annual increases. When adjusting for the exit of the Western Area Power Administration (WAPA) load to the Sacramento Municipal Utility District's control area, average hourly load, average daily peak, and average daily trough (minimum load) all increased between 1.5 and 2.2 percent between February 2004 and February 2005. Figure 1 compares hourly actual loads in February 2004 and 2005. Table 1 shows monthly year-to-year load trends through February 2005.

Figure 1. ISO Actual Load: February 2004 v. 2005

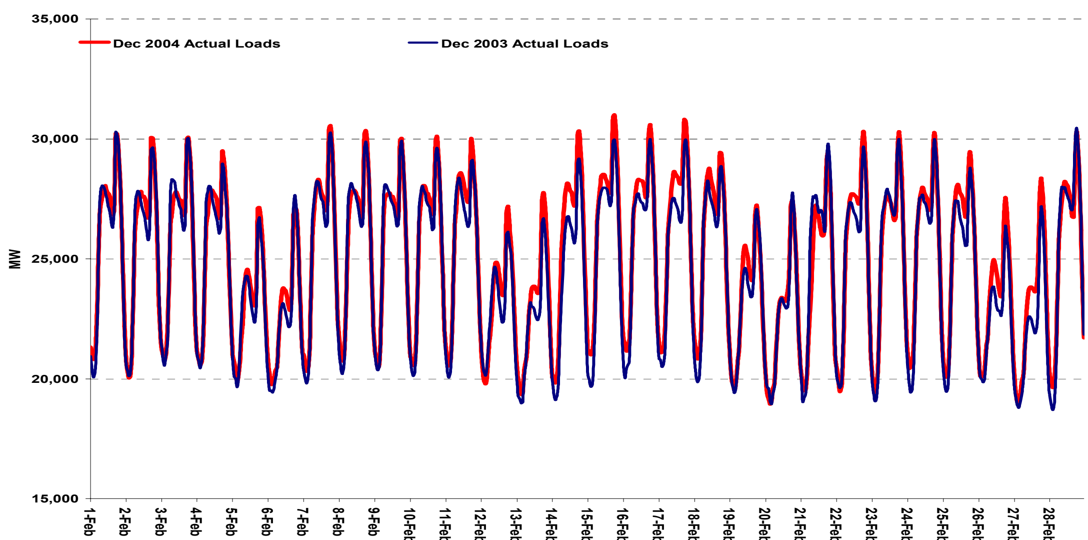


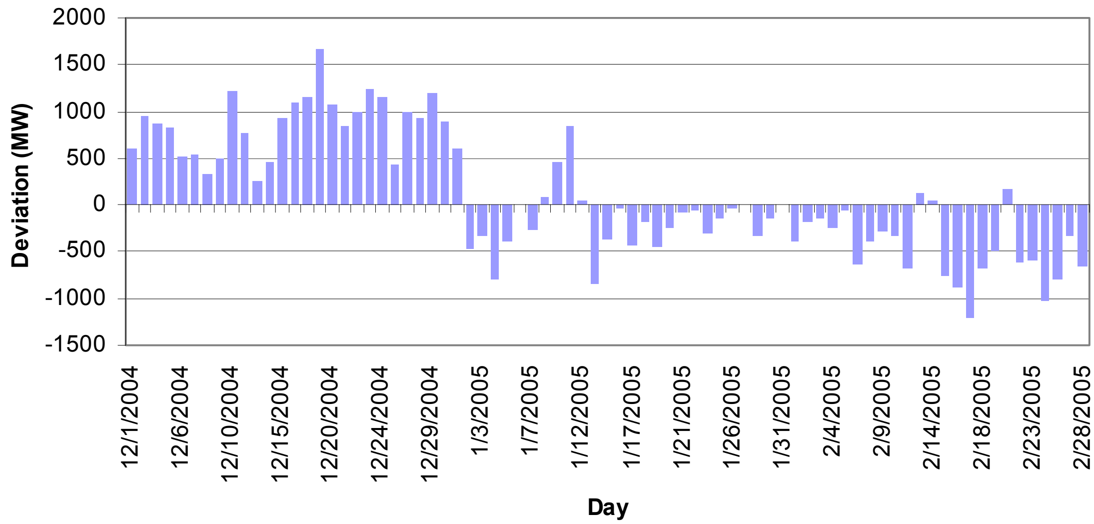
Table 1. Load Growth Rate Indices Compared to the Same Month in the Prior Year[1]

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
March-04	4.4%	5.1%	2.5%	4.5%
April-04	7.1%	8.3%	4.8%	31.1%
May-04	7.3%	7.7%	5.5%	2.5%
June-04	6.6%	6.9%	6.1%	-4.7%
July-04	0.7%	0.3%	1.9%	4.0%
August-04	1.0%	0.6%	0.6%	5.2%
September-04	3.4%	3.5%	3.4%	10.1%
October-04	-1.4%	-2.8%	1.5%	-5.9%
November-04	4.2%	3.9%	3.9%	6.6%
December-04	4.4%	4.1%	6.5%	3.4%
January-05	1.8%	2.8%	1.2%	5.0%
February-05	1.5%	1.8%	2.2%	0.3%

Under-scheduling remains low, averaging 3 percent. However, we have seen under-scheduling more often in January and February, reversing the over-scheduling trend we saw in 2004. This is likely due to a disparity in prices between the forward and real-time markets. Short schedules and higher day-ahead prices may be due in part to the December 31, 2004 expiration of some long-term contracts, causing some load-serving entities (LSEs) to rely more heavily on the spot market for schedules. When day-ahead prices consistently exceed real-time balancing energy prices, some LSEs may schedule less than the volume needed to meet load. They then accept the lower cost of that imbalance in real time. This strategy runs the risk that real-time prices plus uplift costs, which are not known at the time of hour-ahead scheduling, may exceed forward bilateral prices. Figure 2 shows daily average peak-hour net scheduling deviations, including minimum-load energy procured pursuant to the must-offer obligation, since December 1, 2004.

[1] Yearly average reflects 3/1/2004 through 2/28/2005. Data through 7/10/2003 are actual loads at the top of each hour. Data since 7/11/2003 are hourly average loads. Monthly peak load is a metric that is most informative during the summer peak period, when resources are particularly scarce.

Figure 2. Daily Average Net Scheduling Deviations: December 2004 – February 2005[2]

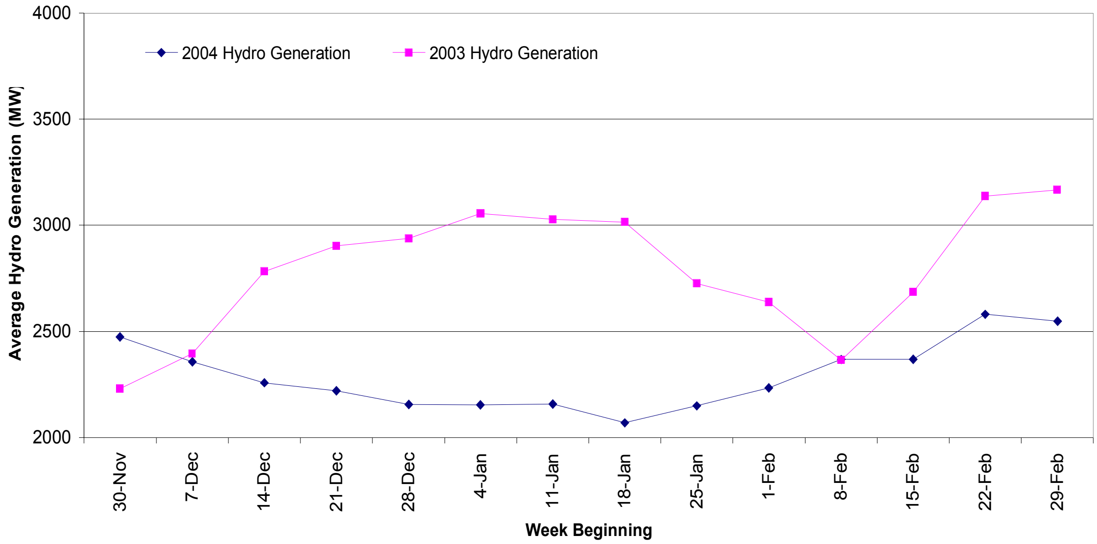


Hydroelectric Conditions. According to the Natural Resources Conservation Service, snow pack is below average in the Pacific Northwest, and above average in the southwest. As of March 3, 2005, the Pacific Northwest snowpack ranged between 16 and 50 percent of average, following unseasonably high temperatures in late February. Meanwhile, snow packs in the California Sierra Nevada, Arizona, and Colorado ranged between 115 and 160 percent of average.

As a typically winter-peaking region, the Pacific Northwest usually supplies hydro generated power to the southwest over the California-Oregon, and Pacific DC Interties during the southwest's summer peak season. An early heat wave in February and March 2004 severely eroded last year's otherwise strong snow pack. It remains to be seen whether this phenomenon will recur in 2005. Significant new thermal generation has been added in the northwest since the 2001 drought, which should soften the impact of below normal northwest hydro runoff, although at a higher price. Figure 3 shows weekly hydro production in California for the 2003-2004 and 2004-2005 hydro seasons.

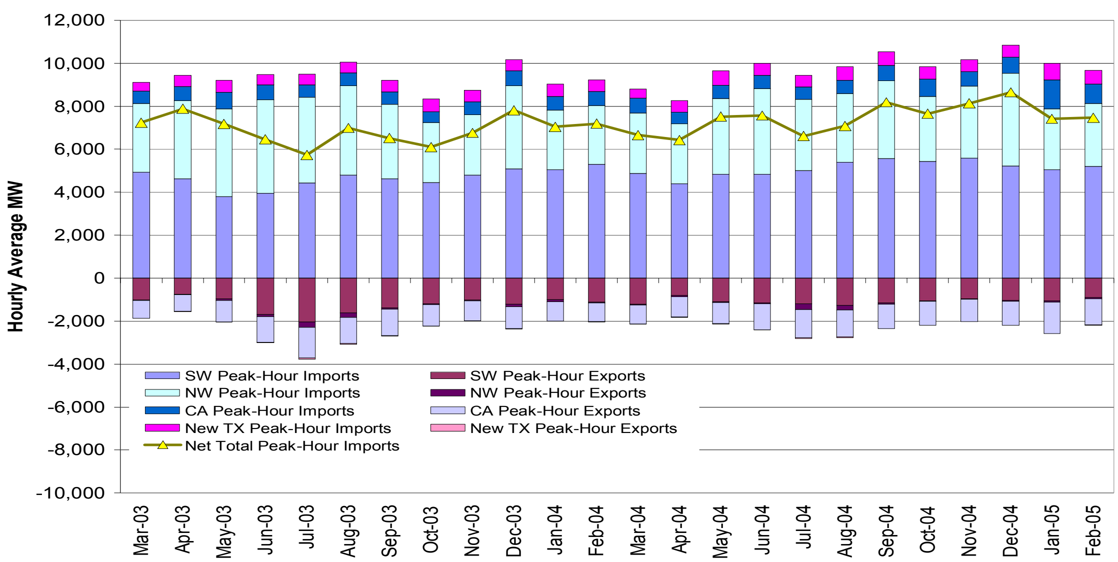
[2] Net scheduling deviation = HA schedules + Must-offer-committed minimum-load MW – actual load

Figure 3. Weekly Average CAISO System Hydroelectric Production: 2003-04 vs. 2004-05



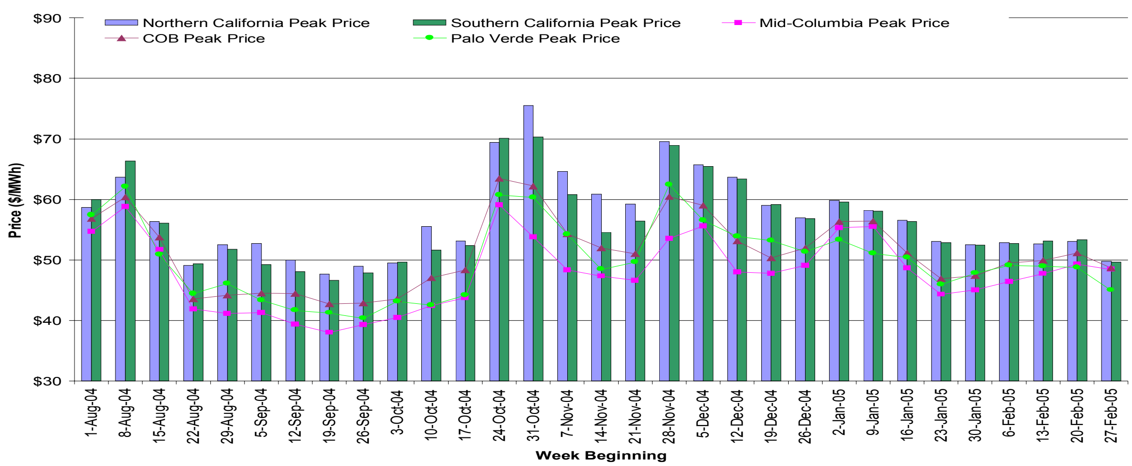
Imports and Exports. Net imported scheduled energy was similar in February to that in January. A decrease in imports from the Sacramento Municipal Utility District, which now serves the Western Area Power Administration, was offset by a decrease in exports to Arizona and Lower Colorado River regions in the southwest. Figure 4 shows monthly average imports and exports by neighboring region through February.

Figure 4. Imports and Exports: Monthly Averages through February



Day-Ahead Bilateral Electric Contract Prices. Prices across the west were stable in February, with NP15 and SP15 day-ahead prices ranging in the neighborhood of $52 to $56/MWh. Since the upgrade of Path 15 in December, south-to-north congestion, which causes a price disparity between NP15 and SP15, has been uncommon. However, congestion on paths into California has resulted in premiums of approximately $4/MWh between Palo Verde and SP15 and between the California-Oregon Border (COB) and NP15. This premium increases to approximately $10/MWh between Mid-Columbia and NP15. Outages of base load coal units in the southwest kept this price spread narrower than it otherwise might have been in early February. That effect may have been offset by unseasonably cool weather in Arizona and Nevada. In the final days of the month, all but Palo Verde prices converged, as weather was forecast to be cool in the Phoenix area. Figure 5 shows weekly average day-ahead bilateral power prices through February 28.

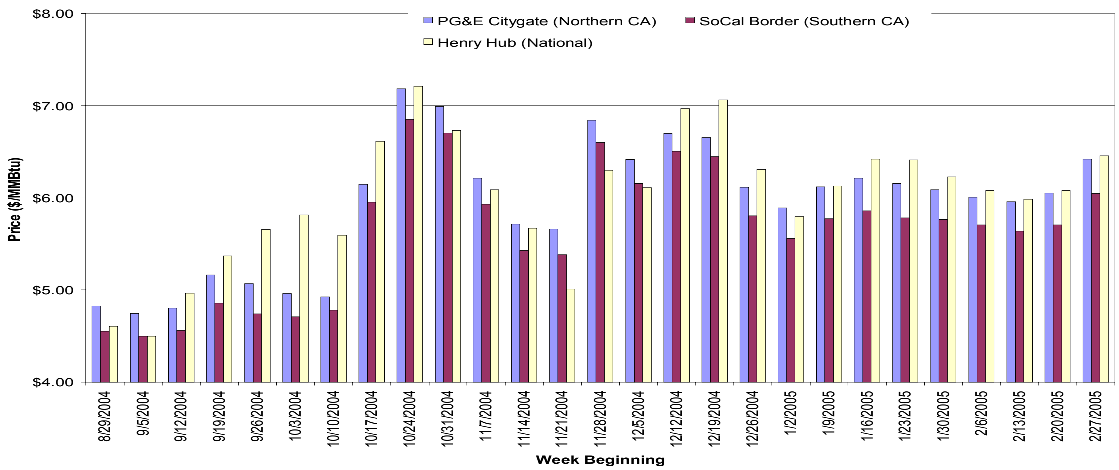
Figure 5. Weekly Average Day-Ahead Bilateral Electricity Contract Prices



Natural gas markets. Western gas market prices decreased slowly over the first three weeks of February. The Southern California Border Average (SCBA) price began around $5.85 per million British Thermal Units (MMBtu) and trended as low as $5.52/MMBtu by February 18-22. The PG&E Citygate (PGEC) price held a premium of approximately 30 cents above the Southern California price, beginning the month at $6.17/MMBtu and easing to $5.86/MMBtu by February 21. While much of the United States experienced cold weather in early February, the middle of the month was warmer. Meanwhile, natural gas in underground storage increased compared to the weekly 5-year average during this period, from 15.1 to 20.9 percent of average during these three weeks. In the final week of the month, both the SCBA and PGEC prices rebounded, due to cold weather across the United States. They closed the month at $6.24 and $6.23/MMBtu, respectively.[3] The 30-cent northern California premium evaporated on the final day of February, as temperatures across California were much the same.[4] Figure 6 shows weekly average prices for natural gas at California and national delivery points.

[3] U.S. Energy Information Administration, *Natural Gas Weekly Update,* Feb. 3, 10, 17, 24, and March 3, 2005, www.eia.doe.gov.
[4] Fisher, D. and K. van Vactor, *Energy Market Report 11 (39),* Feb. 28, 2005, Economic Insight Inc.

Figure 6. Weekly Average Regional Natural Gas Prices



III. Real-Time Market

- *High day-ahead prices lead generators to schedule short of load, recover balance in real-time market*
- *Price spikes have decreased in frequency*

As real-time prices have fallen, volumes have increased substantially. The average price the CAISO paid to suppliers during periods of incremental dispatch was $58.99/MWh in February, approximately $6/MWh below the January level.[5]   This is due in part to growth of real-time import supply in recent months. As CAISO real-time balancing prices have recently been lower than day-ahead energy, both within its control area and at the regional trading hubs, load-serving entities may be speculating that they will incur lower costs by scheduling short of expected load and recovering the difference through real-time balancing. One primary consequence of this behavior is a trend toward incremental balancing, rather than balancing primarily in the decremental direction. Decremental balancing had been prevalent through December 2004 as a result of forward scheduled energy plus minimum load energy committed under the must-offer obligation often being greater than actual load. Overall, the average real-time balancing energy price was $41.11/MWh in February, compared to $42.27/MWh in January.

Table 2 shows monthly average prices, total energy, and loads and underscheduling, for real-time balancing through February. Figures 7 and 8 show hourly average prices and volumes of real-time energy; and average real-time import dispatch volumes.

[5] Real-time prices and volumes between October 2004 and January 2005 will be restated in an upcoming addendum, following the resolution of a data issue. RTMA data originally were and remain subject to change.

Table 2. Real-Time Average Prices and Net Total Energy, and Average Loads and Underscheduling, for February

	In-Seq. RT Dispatch	OOS/OOM Dispatch	Total Dispatch	Average Loads and % Underscheduling
PEAK	$ 46.92 /MWh	$ 18.41 /MWh	$ 41.65 /MWh	26,687 MW
	48.0 GWh	(153.6) GWh	(105.6) GWh	2.0%
OFFPEAK	$ 43.78 /MWh	$ 14.36 /MWh	$ 40.18 /MWh	20,991 MW
	80.6 GWh	(58.2) GWh	22.4 GWh	4.4%
ALL	$ 45.71 /MWh	$ 17.28 /MWh	$ 41.11 /MWh	24,246 MW
	128.7 GWh	(211.9) GWh	(83.2) GWh	3.0%

Figure 7. Hourly Average Prices and Net Volumes for In-Sequence and OOS/OOM Real-Time Balancing Energy in February

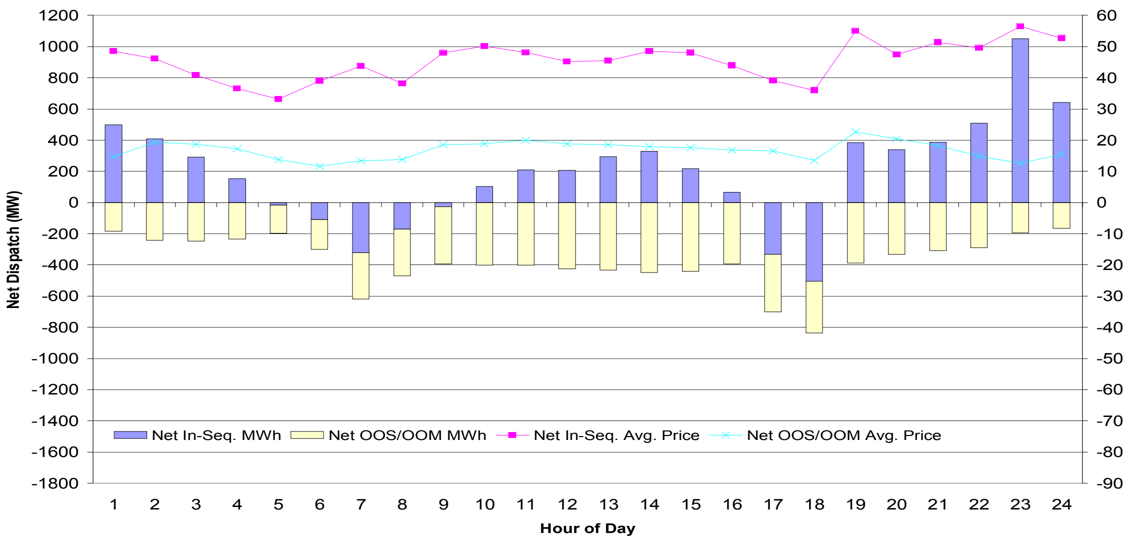
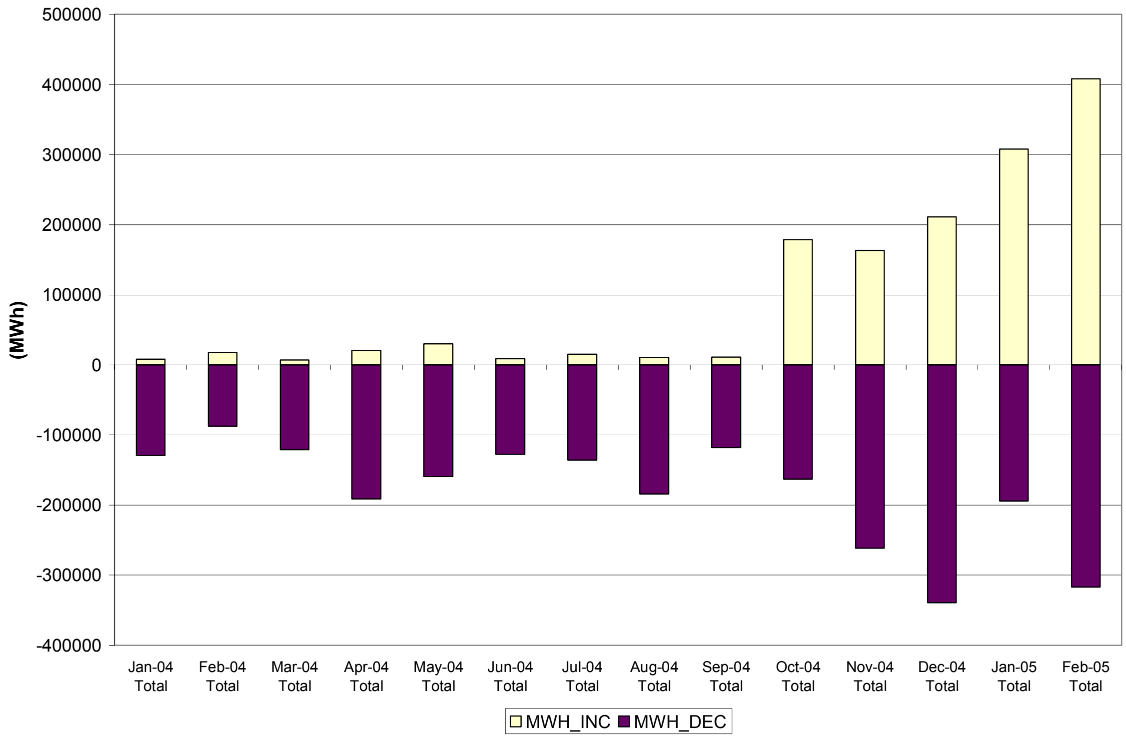


Figure 8. Monthly Average Real-Time Import Dispatch Volumes through February



Price Spikes. Spikes have decreased considerably, to approximately 140 of 8,064 intervals (1.7 percent) in SP15 in February, compared to 316 of 8,928 intervals (3.5 percent) in January. We observed at least one price spike worth noting in February. On February 19, at 1:04 p.m., the Southwest Power Link (SWPL), a transmission line connecting Palo Verde to the SDG&E Control Area via the Miguel Substation, tripped during some maintenance work. This outage was repaired by 1:11 p.m. Meanwhile, it resulted in a spike of the real-time market-clearing price as high as $249/MWh (for a single interval). This price, bid by a high-cost steam unit under RMR contract in NP15, was accepted as the bid stack was exhausted.

Figure 9. January Price Spike Count by Interval

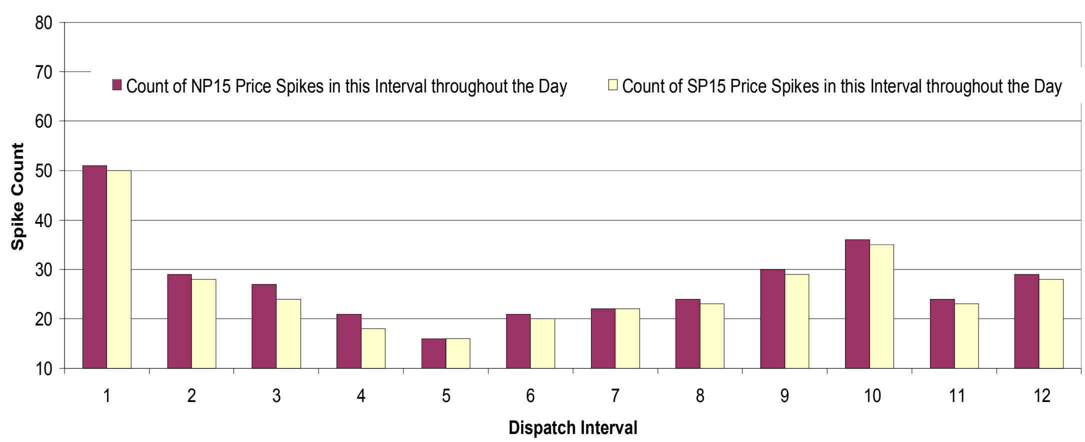
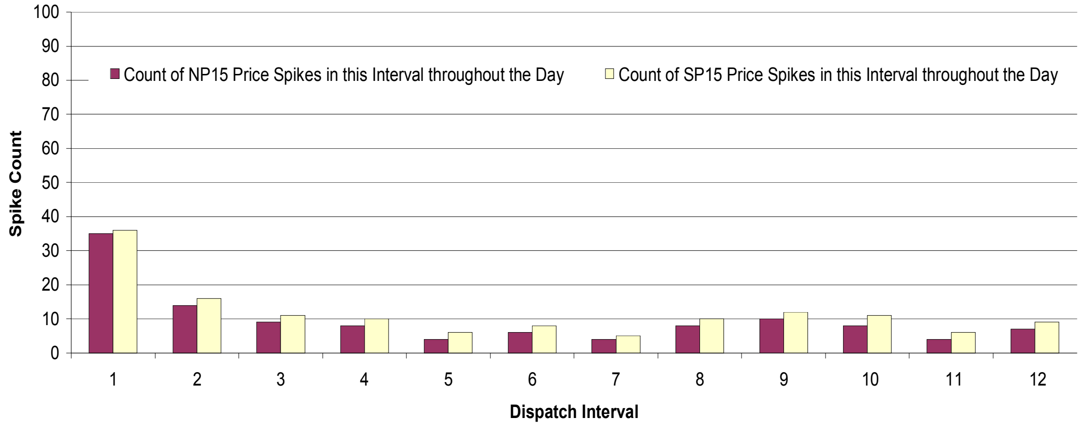


Figure 10. February Price Spike Count by Interval



IV. Intra-zonal (within zone) Congestion

- *Intra-zonal congestion costs down in February*

Total intra-zonal congestion costs across the CAISO are the sum of three different cost components.

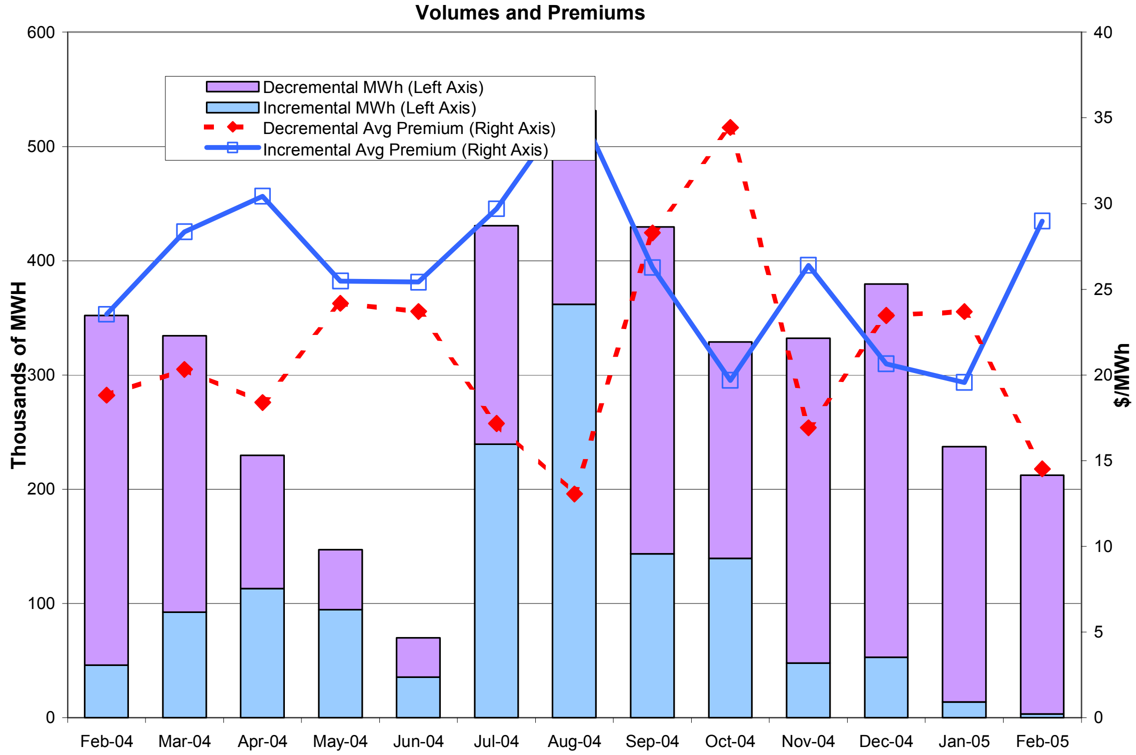
1. MLCC costs are incurred day-ahead as units are constrained so as to be available to provide energy if called upon.
2. RMR costs are incurred in real-time as RMR units are the first to be dispatched to relieve intra-zonal congestion.
3. Redispatch costs are also incurred in real-time if the RMR dispatches are not sufficient to alleviate the constraint.

Due to lags in the CASIO settlements system, MLCC and RMR costs are seldom available for analysis as soon as re-dispatch costs. Because of this, we are only able to analyze re-dispatch costs here.

In February, both incremental and decremental congestion volumes decreased. This resulted in a decrease in both the incremental and decremental redispatch premiums. The decrease in incremental premium was more pronounced. February OOS dispatches resulted in a net cost (re-dispatch premium) of approximately $3.1 million. Total OOS dispatch volume was 212 GWh (INC plus DEC) and the average redispatch premium was $14.74/MWh. This was a decrease from the January average. Figure 11 shows the premiums for recent months.[6]

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

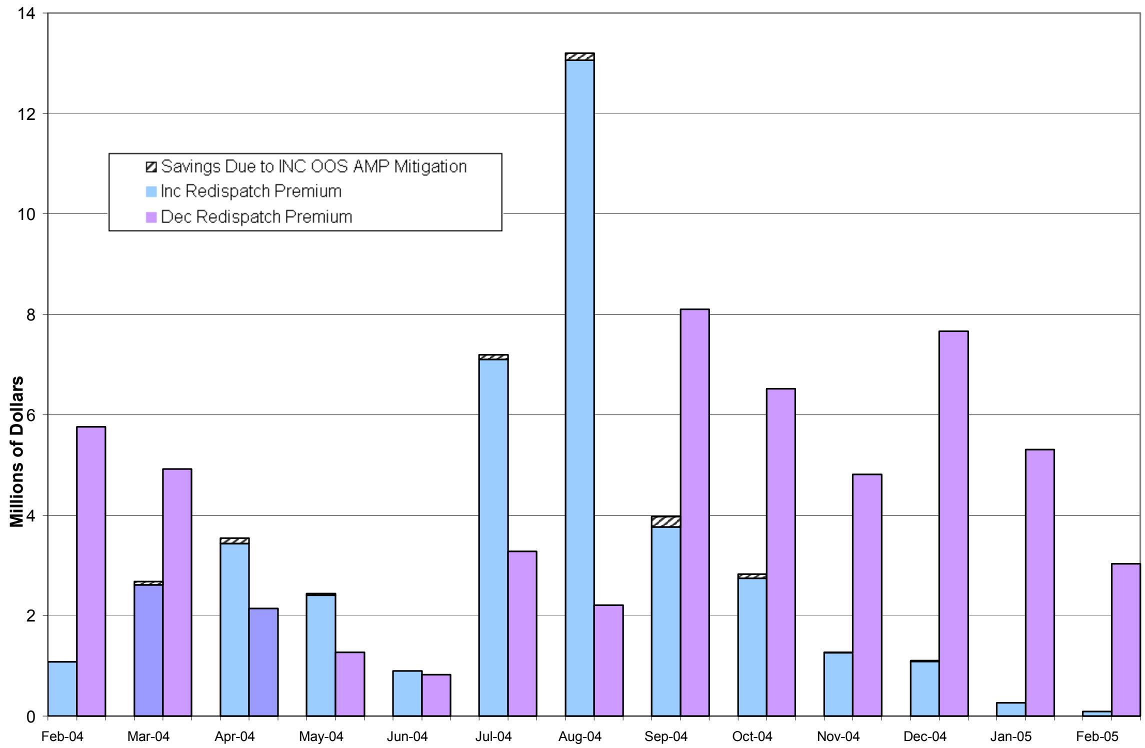
Figure 11. Out-of-Sequence Volume and Average Redispatch Premium



Incremental OOS Dispatches. CAISO operators called a total of 3,234 MWh of incremental energy out-of-sequence (OOS) to address intra-zonal congestion in February. The average price paid was $60.14/MWh in February, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $94,000 or $28.99/MWh.

Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of $174 or approximately 0.2 percent of the incremental re-dispatch premium. All incremental OOS dispatches are subject to mitigation Figure 12 shows the re-dispatch premiums for both decremental and incremental congestion as well as the savings due to mitigation of incremental OOS dispatches. As the chart shows, very little bid mitigation has taken place due to the large thresholds in AMP for local market power.

Figure 12. Re-dispatch Premiums and INC OOS Mitigation Savings



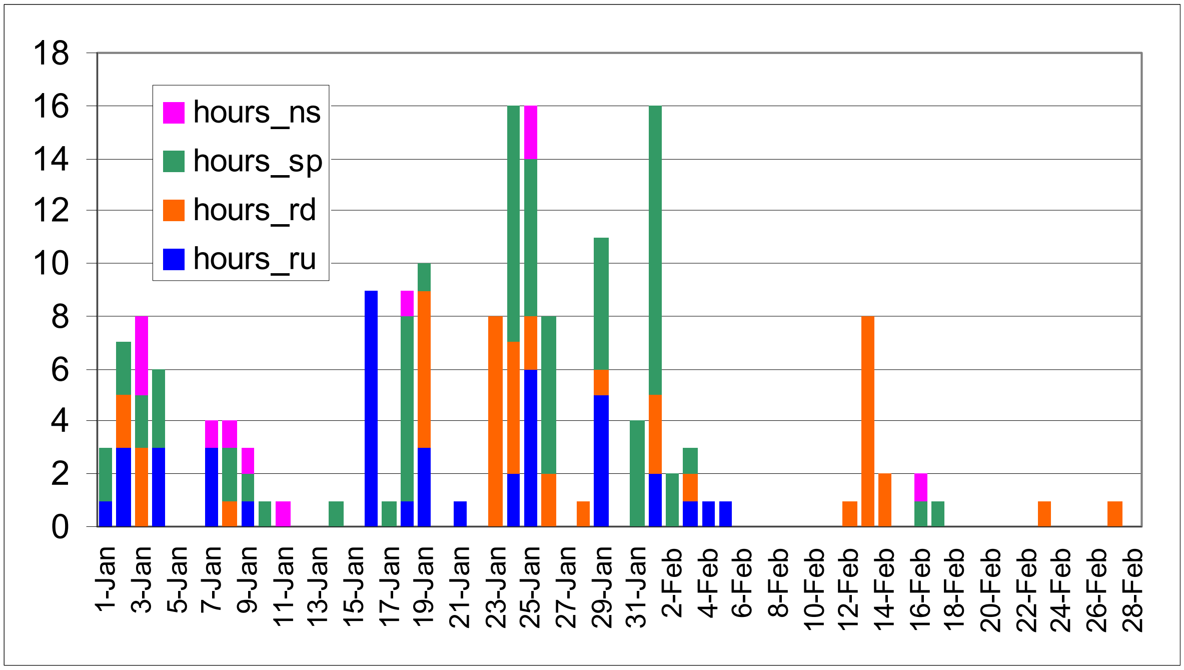
Decremental OOS Dispatches. The CAISO dispatched a total of 209 GWh of decremental energy out of sequence in February. The average price paid was $11.18/MWh, a decrease of 50 percent from January. The re-dispatch premium in excess of the market clearing price (MCP) was approximately $3 million or $14.52/MWh. This energy was settled according to the provisions of the FERC-approved Amendment 50 mitigation measures. Reduced amounts of decremental redispatch for Miguel mitigation resulted in a division of decremental redispatch costs that was different from previous months. We can attribute about 25 percent of re-dispatch costs to work at the Cortina Substation in northern California, while we attribute 72 percent to Miguel congestion.

V. Ancillary Services Markets

- *Decrease in bid insufficiency in February*

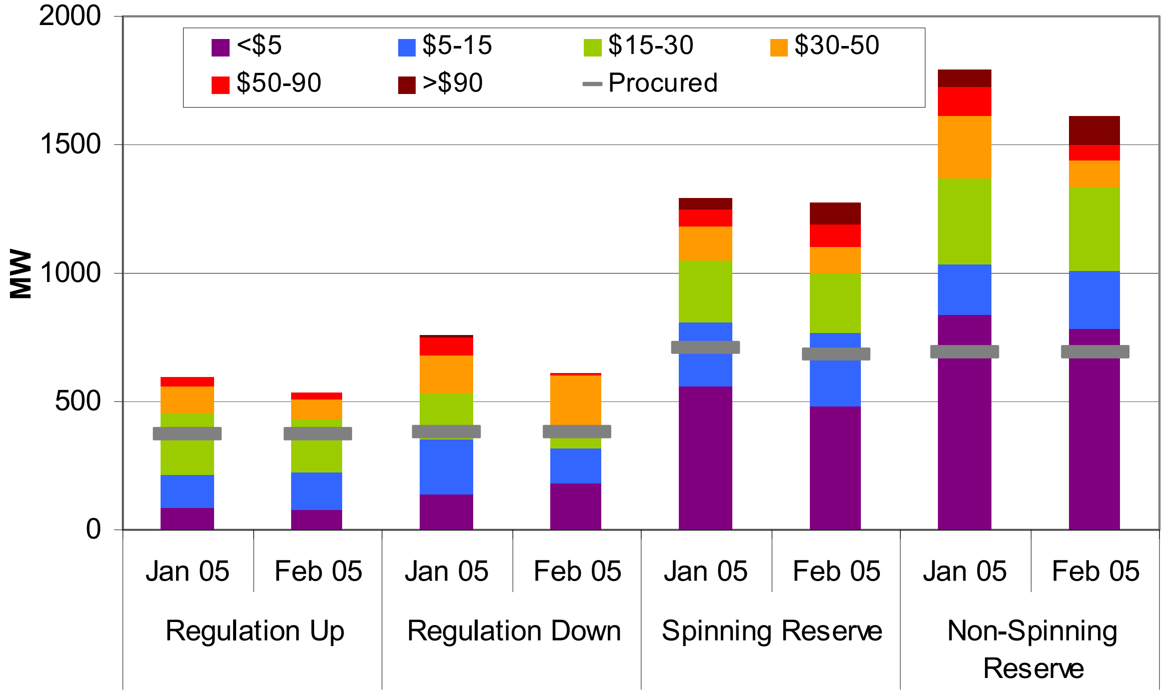
We saw a significant decrease in ancillary service market bid insufficiency in February compared to January, although there was still some bid insufficiency in regulation-down market during off-peak hours. Figure 13 shows the number of bid insufficient hours for each service in the day-ahead market in January and February.

Figure 13. Number of bid insufficient hours in January and February 2005



Market Supply. Supply of capacity to the A/S markets decreased slightly from January to February. This resulted in procurement migrating up the bid bin stack across the board. This was most pronounced in regulation down where the bid volumes in the $5 - $15/MW and the $15-$30/MW ranges were substantially reduced. Figure 14 shows bid volumes by price bin in January and February 2005.

Figure 14. Ancillary Service Day-Ahead Average Bid Volume by Price Bin



Market Prices. Decreased bid insufficiency resulted in lower A/S market prices in February compared to January 2005, with the exception of regulation down. The weighted average prices of all services decreased slightly, again with the exception of regulation-down where prices increased slightly. Table 3 shows ancillary service product requirements and average prices for January and February.

Table 3. Average Ancillary Service Requirements and Prices

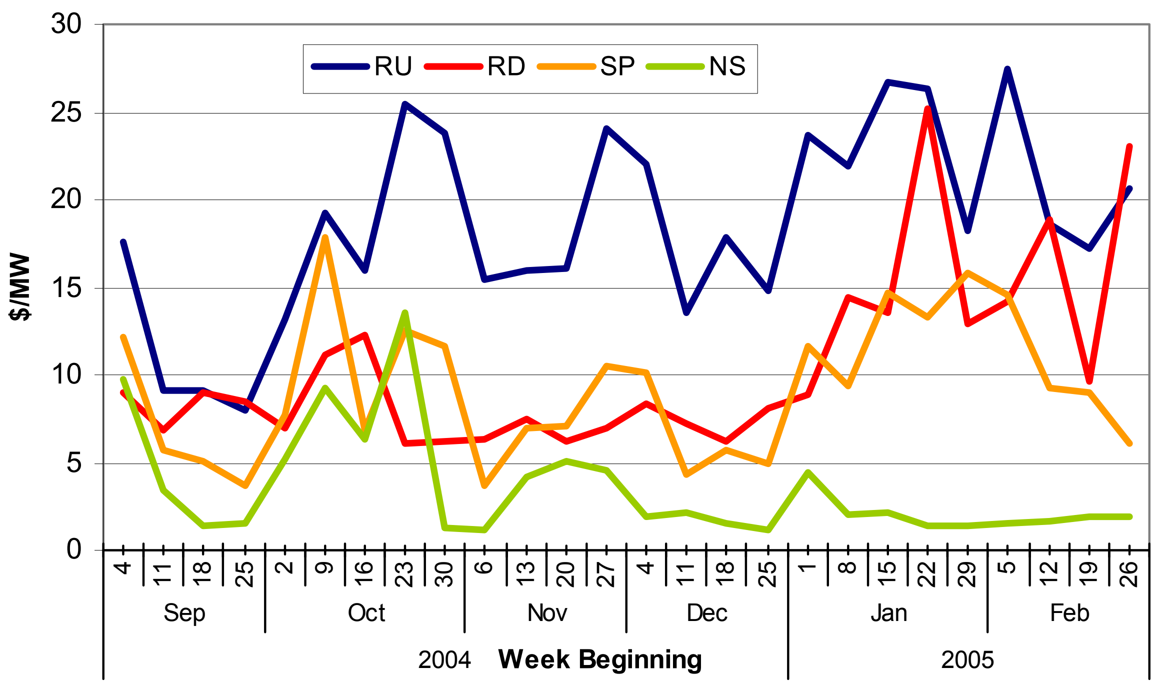
	Average Required (MW)				Weighted Average Price ($/MW)			
	RU	RD	SP	NS	RU	RD	SP	NS
Jan 05	377	389	773	771	$ 23.64	$ 14.86	$ 12.01	$ 2.37
Feb 05	384	379	763	779	$ 21.01	$ 15.38	$ 11.66	$ 1.73

Overall, A/S procurement decreased 0.3% between January and February. The weighted average price of ancillary services decreased from $11.17 in January to $10.47 in February, a decrease of 6.3 percent. Table 4 summarizes the A/S procurement and Figure 15 depicts price trends over the past six months.

Table 4. Peak and Off-Peak Ancillary Service Procurement and Pricing

		Average AS Procured (MW)			Weighted Average Price ($/MW)		
		On-Peak	Off-Peak	All Hours	On-Peak	Off-Peak	All Hours
Jan 05	RU	383	366	377	$ 26.10	$ 18.51	$ 23.64
	RD	394	380	389	$ 10.58	$ 23.75	$ 14.86
	SP	810	700	773	$ 14.80	$ 5.55	$ 12.01
	NS	810	693	771	$ 2.83	$ 1.32	$ 2.37
	Total	2397	2140	2311	$ 11.86	$ 9.63	$ 11.17
Feb 05	RU	389	373	384	$ 23.11	$ 16.64	$ 21.01
	RD	375	387	379	$ 11.47	$ 22.98	$ 15.38
	SP	792	704	763	$ 14.99	$ 4.16	$ 11.66
	NS	811	715	779	$ 1.94	$ 1.24	$ 1.73
	Total	2367	2179	2305	$ 11.30	$ 8.68	$ 10.47
Difference	RU	6	7	6	$ (2.99)	$ (1.88)	$ (2.63)
	RD	-18	7	-10	$ 0.90	$ (0.78)	$ 0.52
	SP	-18	4	-11	$ 0.20	$ (1.39)	$ (0.35)
	NS	1	21	8	$ (0.89)	$ (0.07)	$ (0.65)
	Total	-29	40	-6	$ (0.57)	$ (0.95)	$ (0.70)

Figure 15. Weekly Weighted Average Ancillary Service Prices



IV. Inter-zonal Congestion Markets

- *Inter-zonal congestion costs totaled $1.1 million in February, significantly lower than the $4.2 million in January.*
- *Inter-zonal congestion costs were largely due to transmission constraints on the Palo Verde and Blythe Interties.*

Inter-zonal congestion costs totaled $1.1 million in February, significantly lower than the $4.2 million in January. The vast majority of all congestion in February was on four paths, the Palo Verde branch group (73 percent), the BLYTHE branch group (12 percent), the California-Oregon Intertie (COI) (6 percent), and the newly created TRACYWAPA branch group between SMUD and NP15 (5 percent).

Table 5: Inter-Zonal Congestion Costs in February 2005

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost	Total Cost Percent
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead		
BLYTHE	$133,570	$0	$0	$0	$133,570	$0	$133,570	$0	$133,570	12%
COI	$56,885	$0	$4,855	$0	$61,740	$0	$56,885	$4,855	$61,740	6%
ELDORADO	$1,308	$0	$0	$0	$1,308	$0	$1,308	$0	$1,308	0%
IPPDCADLN	$0	$0	$6,153	$0	$6,153	$0	$0	$6,153	$6,153	1%
MEAD	$5,636	$0	$1,765	$0	$7,401	$0	$5,636	$1,765	$7,401	1%
NOB	$0	$0	$1,602	$0	$1,602	$0	$0	$1,602	$1,602	0%
OLNDAWAPA	$0	$0	$0	-$37	$0	-$37	$0	-$37	-$37	0%
PALOVRDE	$786,477	$0	$902	$0	$787,378	$0	$786,477	$902	$787,378	73%
PATH15	$23,778	$0	$0	$0	$23,778	$0	$23,778	$0	$23,778	2%
TRACYWAPA	$0	$50,008	$0	-$156	$0	$49,853	$50,008	-$156	$49,853	5%
TRCYWSTLY	$0	$0	$10	$0	$10	$0	$0	$10	$10	0%
Total	$1,007,654	$50,008	$15,287	-$193	$1,022,941	$49,815	$1,057,662	$15,094	$1,072,756	100%

The Palo Verde branch group was congested in the import direction (east-to-west) for 39 percent of all hours in the day-ahead (DA) market at an average congestion price of $2/MWh. It was congested 6 percent of all ours in the hour-ahead (HA) market, at an average congestion price of $23/MWh. Congestion on Palo Verde was due, in large part, to wheeling energy from the southwest to northern California where DA bilateral prices were higher.

The BLYTHE branch group was congested only for 1 percent of all hours in the DA import direction (south-to-north) at an average congestion price of $94/MWh, and 1 percent of all hours in the HA import direction at an average price of $157/MWh. Day-ahead congestion occurred on February 9, from HE 9 to HE 16, due to scheduled test at the Eagle Mountain substation. After the day-ahead market ran, the Blythe branch group was derated in the import direction from 185 MW to 17 MW on February 9, from HE 11 to HE 13. This caused congestion in HA during this time period with the congestion price ranging from $64/MWh to $250/MWh.

COI was congested only for 1 percent of all hours in the DA import direction (from Oregon to California) at an average congestion price of $5/MWh. This was, significantly lower than the congestion frequency and magnitude in January. COI was congested for 3 percent of all hours in the HA import direction at an average price of $6/MWh, also much less frequent than in January. COI experienced almost daily deratings throughout the month due to various line/capacitor outages and scheduled line work.

The new branch group TRACYWAPA between SMUD and NP15 also experienced significant congestion cost in DA import direction. Congestion occurred on two occasions, one on February 16, from HE 7 to HE 16 when TRACYWAPA intertie was derated due to planned station work at TRACY switchyard. Congestion occurred again on February 25, from HE 1 to HE 24, also due to deratings.

Table 6: Inter-Zonal Congestion Prices and Frequencies in February 2005

	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
BLYTHE	1	0	$94		1	0	$157	
CASCADE	0	0			1	0	$0	
COI	1	0	$5		3	0	$6	
ELDORADO	4	0	$0		2	0	$37	
IPPDCADLN	0	0			0	0	$50	
MEAD	20	0	$0		10	0	$11	
NOB	0	0			3	0	$21	
PALOVRDE	39	0	$2		6	0	$23	
PATH15	0	0	$2		0	0	$1	
TRACYWAPA	0	1		$250	0	0		

V. Firm Transmission Rights

A firm transmission right (FTR) is a right that has the attributes of both financial and physical transmission rights. FTRs entitle their owners to share in the distribution of usage charge revenues received by the CAISO (in the day-ahead and hour-ahead markets) in connection with inter-zonal congestion during the period for which the FTR is issued. FTRs also entitle registered FTR holders to certain scheduling priorities (in the day-ahead market) for the transmission of energy across a congested inter-zonal interface.

FTR Scheduling. FTRs can be used to hedge against high congestion prices and establish scheduling priority in the day-ahead market. Table 7 shows that a high percentage of FTRs were scheduled on a few paths (96 percent on ELDORADO, 61 percent on IID-SCE, 45 percent on PALOVRDE, 96 percent on SILVERPK, and 27 percent on Path 26). Southern California Edison Company and municipal utilities primarily own the FTRs on these paths.

Table 7. FTR Scheduling Statistics for February 2005*

Branch Group	Direction	MW FTR Auctioned	Avg. MW FTR Sch.	Max MW FTR Sch.	Max Single SC FTR Sch.	% FTR Schedule
BLYTHE	IMP	168	12	167	167	7%
ELDORADO	IMP	536	517	536	536	96%
IID-SCE	IMP	600	365	468	448	61%
MEAD	IMP	624	23	57	26	4%
NOB	IMP	725	6	29	23	1%
PALOVRDE	IMP	1021	460	700	550	45%
SILVERPK	IMP	10	10	10	10	96%
VICTVL	IMP	921	1	25	25	0%
NOB	EXP	722	17	62	39	2%
PATH26	EXP	1314	349	370	370	27%

*only those paths on which 1percent 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 8 summarizes the FTR revenue collected through February 2005. Only Palo Verde (import direction) had significant positive FTR revenues. It had $3,843/MWh, in February, due to a higher occurrence of congestion. BLYTHE had the second highest FTR revenue, $969/MWh. This was also due to higher occurrence of congestion.

Table 8. FTR Revenue Per MW ($/MW)

Branch Group	Direction	Net $/MW FTR Rev Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan. 2005	Feb. 2005	Cumm Net $/MW FTR Rev	Pro Rated Net $/MW FTR Rev
BLYTHE	IMPORT	2791	5540	433	0	7	736	332	992	0	0	969	11799	12283
COI	IMPORT	697	5185	16985	2876	1823	8939	6551	7652	7084	2904	267	60963	62549
ELDORADO	IMPORT	0	408	10	0	0	400	136	156	19	4	1	1134	1136
LUGOGNDRI	IMPORT	0	0	0	0	0	0	0	176	0	0	0	176	176
LUGOIPPDC	IMPORT	9	0	0	0	0	0	0	0	0	0	0	9	9
LUGOMKTPC	IMPORT	0	0	0	0	7	224	764	0	0	0	0	995	995
LUGOMONAI	IMPORT	0	0	0	0	0	408	216	99	3	0	0	725	725
LUGOTMONA	IMPORT	0	0	576	0	0	24	0	0	0	0	0	600	600
LUGOWSTWG	IMPORT	0	2	0	1	52	2036	0	0	0	0	0	2090	2090
LUGOWSWGI	IMPORT	0	0	0	0	0	888	422	52	364	0	0	1726	1726
MEAD	IMPORT	1223	1168	634	464	238	930	1114	2386	849	1	53	9060	9087
NOB	IMPORT	458	2477	26077	5080	1382	1734	0	0	638	0	11	37856	37862
PALOVRDE	IMPORT	2666	19474	3159	12220	10508	21496	11321	7791	6645	11919	3843	111043	118924
PARKER	IMPORT	115	15	0	5	6	178	0	0	252	0	0	571	571
PATH15	S-N	0	98	100	25	1435	2983	15525	3759	0	26	30	23982	24010
SILVERPK	IMPORT	0	0	0	0	5	0	0	176	0	0	0	181	181
NOB	EXPORT	0	0	0	910	522	0	0	0	0	0	0	1433	1433
PATH26	N-S	1280	82	1071	1720	416	65	679	0	0	0	0	5314	5314
SILVERPK	EXPORT	0	0	0	0	480	0	0	0	0	0	0	480	480
SUMMIT	EXPORT	0	0	608	0	39	0	0	0	0	0	0	647	647
VICTVL	EXPORT	0	0	0	0	0	0	0	0	0	0	0	0	0