CALIFORNIA ISO

# Memorandum

**To:** ISO Board of Governors

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

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

**Date:** January 21, 2005

***Re:*** ***Market Analysis Report for November and December 2004***

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

## EXECUTIVE SUMMARY

The approximate 4 percent annual growth trend in load that has persisted since mid-2003 continued during November and December. Daily minimum loads, which are less weather sensitive, increased by 3.9 and 6.5 percent respectively.

Out-of-sequence dispatches to mitigate intra-zonal congestion in November and December had a net cost (re-dispatch premium) of approximately $6.1 and $8.7 million respectively. Incremental intra-zonal congestion moderated slightly while decremental congestion increased. This resulted in out-of-sequence (OOS) calls, usually limited to SP15, due largely to mitigation of intra-zonal congestion and workarounds of an outage of the San Onofre Nuclear Generating Station Unit 3 in Southern California. The real-time market continued to be punctuated by fairly predictable price spikes. Some spikes were brief, five to ten minutes in length, usually at the beginning of the hour. Others tended to last approximately one-half hour. These longer spikes were also within SP15, and usually coincided with the aforementioned OOS calls. Both types of price spikes occurred almost on a daily basis, particularly during the evening ramp period between 5:00 and 7:00 p.m., due to load driven by lighting and household use. This has resulted in a slight net increase in redispatch volume and cost, with December's level near that seen in September.[1]

Many generators, including at least three key western nuclear units, were offline in November for scheduled maintenance. This resulted in periods of significant bid insufficiency in the day-ahead ancillary services markets when grid conditions necessitated zonal procurement. Operating reserve prices frequently spiked during periods when ancillary service market offers were insufficient to meet the CAISO's reserve requirements. In December, improving grid conditions allowed operators to procure ancillary services on a system-wide basis.

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[1] The data underlying the information in this report represent the best available at the time of writing. Due to frequent improvements in ISO systems, the data and analyses are subject to change.

Most of the offline units returned to service by early January. Path 15, the Pacific DC Intertie, and the Miguel Substation have been upgraded and returned to service. If other conditions remain the same, these structural improvements to the grid should decrease congestion and improve reliability. Inter-zonal (between zone) congestion costs totaled $4.8 million and $3.3 million in November and December, respectively, due largely to transmission constraints on Palo Verde and the California-Oregon Intertie. The upgrade of Path 15 went into commercial operation on December 22. This upgrade increased the transfer capability from 3,900 MW to 5,400 MW . The upgrade significantly reduced congestion costs and allowed a 40 percent increase in scheduled flows between Northern and Southern California in late December.

## DETAILED SUMMARY & DISCUSSION

### I. Trends Affecting Market Supply and Demand

**Loads.** Loads have continued their growth trend of approximately 4 percent per year. We have observed this trend fairly consistently since the summer of 2003. Average hourly loads increased 4.2 percent and 4.4 percent in November and December 2004 from the same months in 2003. Loads were higher nearly every day in November and December 2004 than in the previous year, including during holiday periods. Figures 1 and 2 show CAISO actual hourly loads in November and December compared to those in previous years (adjusted for days of the week).

**Figure 1. CAISO Actual Loads in November 2004 v. November 2003**

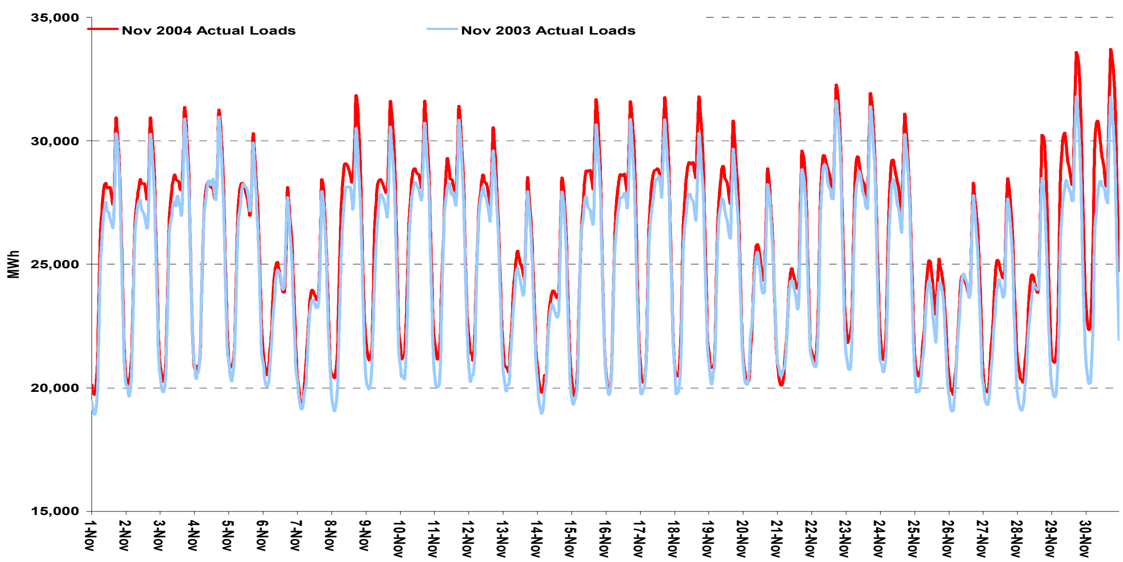
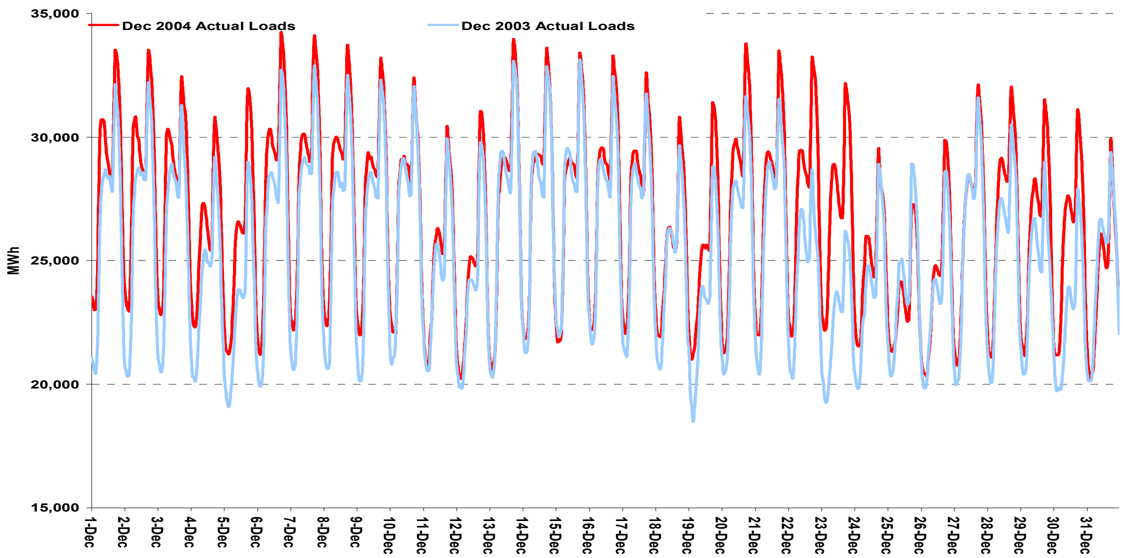


**Figure 2. CAISO Actual Loads in December 2004 v. December 2003**




This growth pattern has persisted in other load metrics; for example, the average daily trough (minimum hourly load), which tends to be less sensitive to weather, increased 3.9 and 6.5 percent in November and December. The only month in 2004 in which load decreased was October, which was unseasonably mild. However, the trough index for October 2004 indicates growth of 1.5 percent over the previous October. Table 1 shows load growth indices (average hourly load, average daily peak, average daily trough, and monthly peak) for each month in 2004, compared to the same month in 2003. It also includes averages for the entire year.

**Table 1. Load Growth Rate Indices Comparing 2004 and 2003 Monthly Loads**[2]

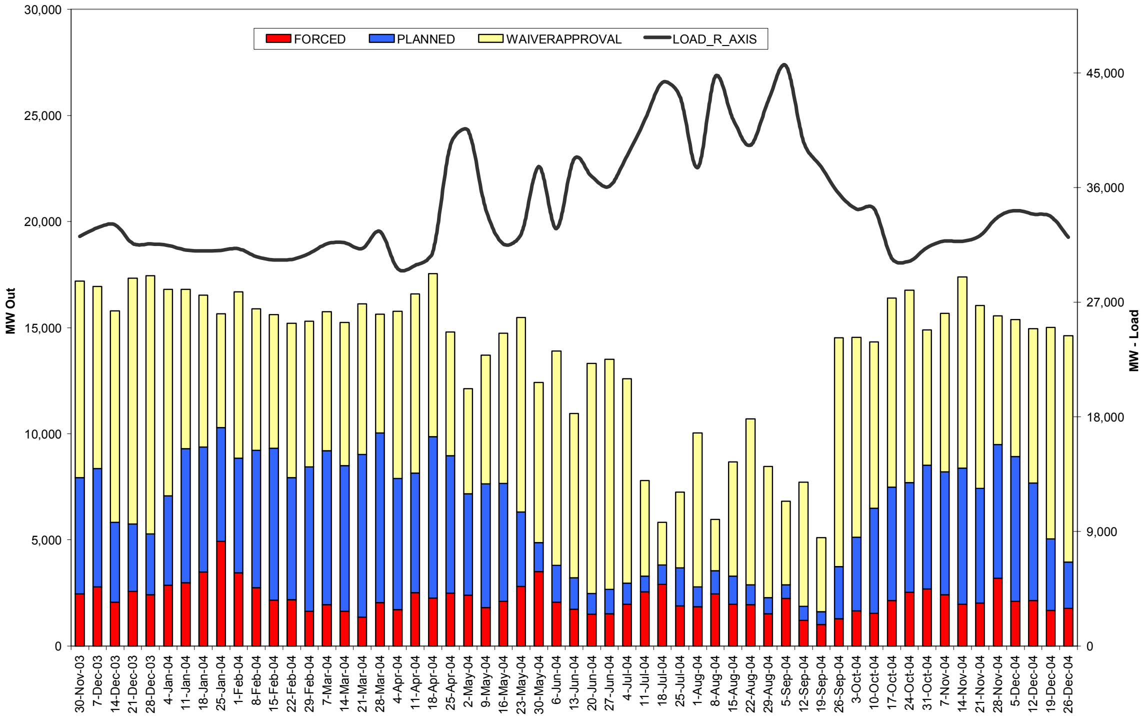
| | Avg. Hrly. Load | Avg. Daily Peak | Avg. Daily Trough | Monthly Peak |
|---|---|---|---|---|
| **January-04** | 4.3% | 3.1% | 5.1% | 3.2% |
| **February-04** | 4.5% | 3.9% | 5.4% | 4.5% |
| **March-04** | 4.4% | 5.1% | 2.5% | 4.5% |
| **April-04** | 7.1% | 8.3% | 4.8% | 31.1% |
| **May-04** | 7.3% | 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% |
| **Annual Average** | 3.7% | 3.5% | 3.8% | 4.9% |

**Transmission Outages.** The Pacific DC Intertie, which connects Southern California load directly to generation in the Pacific Northwest, was brought back to service after upgrade work in December. The path returned to 1,000 MW service on December 9, and then to 2,000 MW service on December 22. The California-Oregon Intertie (COI), which had been derated to approximately 3,400 MW in October, and then again to 1,900 in the first week of November, returned to full capacity of approximately 3,800 MW by the second week of November. The Miguel Substation, east of San Diego, was also upgraded and returned to service on October 31. This upgrade increased the most binding constraint at that location from approximately 1,100 MW to 1,200 MW.

**Generation Outages.** Key units were out of service for planned maintenance during the low load season. The San Onofre Nuclear Generating Station ("SONGS") Unit 3 (1,109 MW) was out from September 29 to December 29, 2004. The Diablo Canyon nuclear Unit 2 (1,105 MW) was also out from October 25 to December 16. Both were out for refueling. Palo Verde Unit 2 has been out since early October. In light of the SONGS 3 outage, the CAISO frequently denied applications from SP15 generation units for waivers of the Must-Offer Obligation in November in order to retain units on-line to mitigate zonal congestion within SP15. The Southern California Import Transmission (SCIT) Nomogram, a technical limit on the amount of power that can instantaneously be imported into the SP15 zone, was binding on a regular basis throughout the month. Figure 3 shows CAISO weekly average generation capacity subject to outage through December 31.

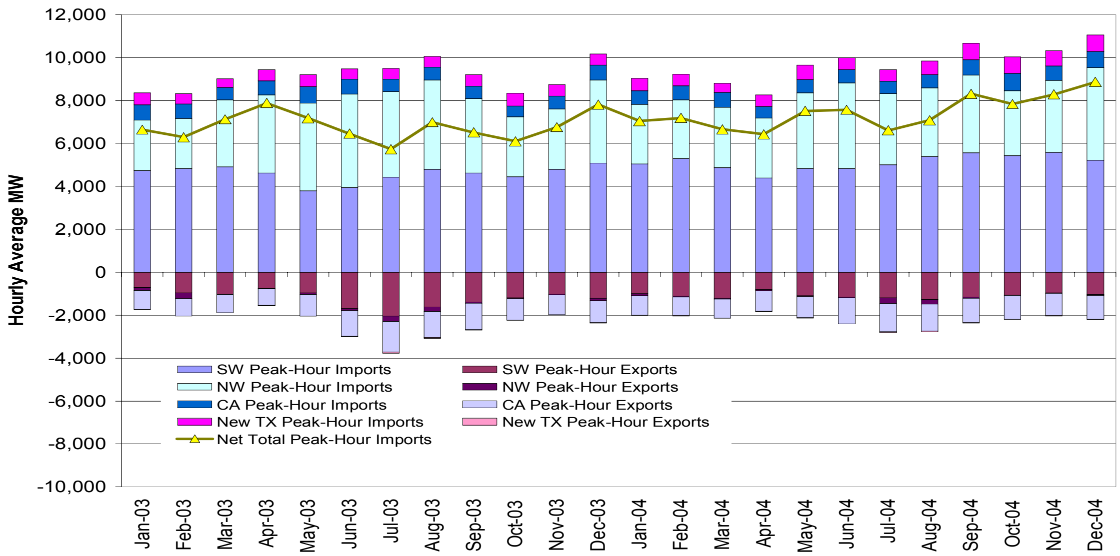
[2] Through 7/10/03: Actual loads at top of hour. Since 7/11/03: Hourly average loads. Annual average is weighted for number of days per month, daylight savings, and leap year.

**Figure 3. Weekly Average CAISO Generation Outages and Peak Load through December**




**Imports and Exports.** Average net imports were 6,181 and 6,412 MW during peak hours in November and December, respectively, compared to 5,419 MW in October. This was due largely to an increase in imports from the Northwest. Imports increased primarily because of the return of the Pacific DC Intertie in December, and to a lesser extent the re-rating of COI in November. Figure 4 shows monthly average peak-hour imports and exports by neighboring exchange region and total net peak-hour imports, through December.

**Figure 4. Monthly Average Imports and Exports by Neighboring Region, and Net Total Imports, through December 2004**[3]

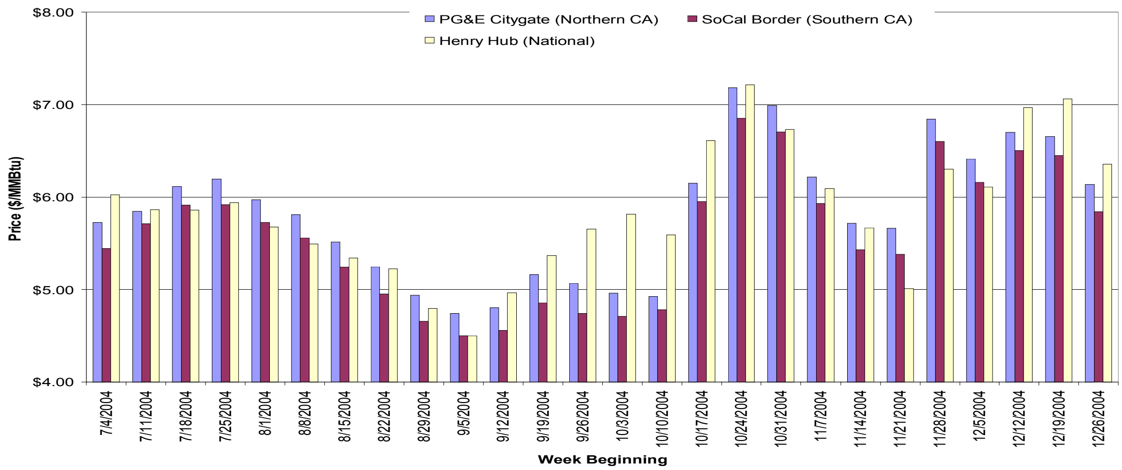



**Natural Gas Markets.** Average natural gas prices in California increased from October to November while average prices at Henry Hub declined in November. The highest average weekly price occurred during the first week of November, when cold weather and high NYMEX futures prices drove spot prices past $7/MMBtu. As temperatures moderated and NYMEX prices fell, prices steadily decreased through November, with the last week of November having the lowest weekly average spot prices of $5.90/MMBtu in California.

Substantial purchases associated with the covering of short natural gas positions and a larger-than-expected 49 Bcf withdrawal from storage reported by EIA drove cash prices back to $7/MMBtu levels in early December. This rally was only temporary, as prices fell below $7/MMBtu by December 3. California prices remained in the $6-7/MMBtu range for the remainder of December, but Henry Hub prices the $7/MMBtu range by mid-December exceeded California averages as heating demand throughout much of the country increased demand for natural gas. Average daily gas prices for November were $5.89/MMBtu at Henry Hub, $5.74/MMBtu at Malin, $6.19/MMBtu at PG&E Citygate, and $5.91/MMBtu at Southern California Border Average. Average daily gas prices for December were $6.60/MMBtu at Henry Hub, $6.12/MMBtu at Malin, $6.54/MMBtu at PG&E Citygate, and $6.30/MMBtu at Southern California Border Average. Figure 5 shows weekly average western natural gas prices through December.

[3] "New TX" indicates participating transmission added to the ISO since January 1, 2003. Transmission on these lines (largely to the Southwest) are not counted in the "SW" categories.

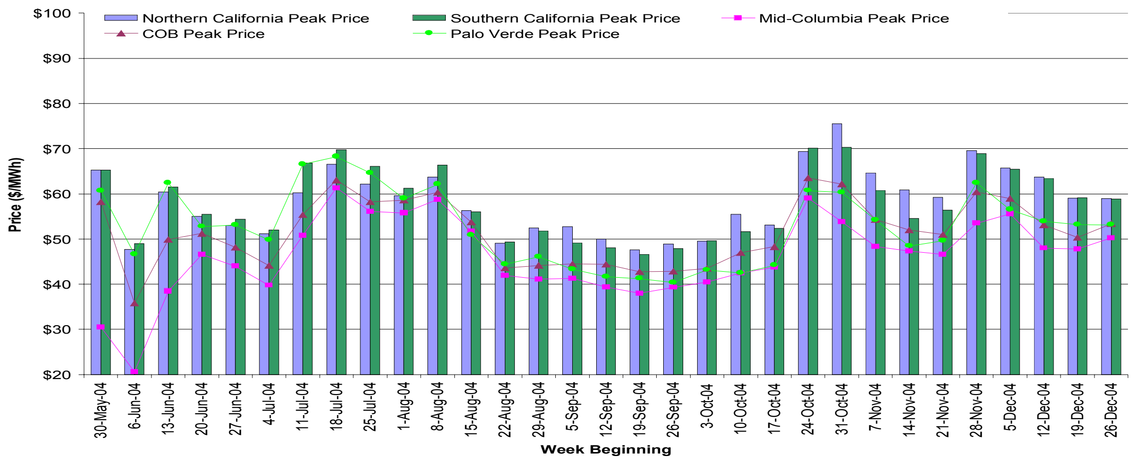
**Figure 5. Weekly Average Western Regional Gas Prices through December**




**Western Regional Bilateral Electric Spot Markets.** Day-Ahead electricity followed changes in natural gas prices. The continuing high natural gas prices from late October continued to drive average California electricity prices for the first week of November past the $73/MWh range, with Northern California prices peaking at $81.00/MWh on November 4. After the first week of November, decreasing natural gas prices resulted in steadily decreasing day-ahead electricity prices. The higher Northern California gas prices resulted in substantial differentials between Northern and Southern California regional electricity prices until the final week of November. By the end of November, California prices were around $65/MWh.

The sudden increase in natural gas prices across the country resulted in electricity prices increasing sharply on November 30; Northern California prices returned to $81.00/MWh, with Southern California prices only slightly lower. As natural gas prices moderated, peak prices remained in the $65-70/MWh for the remainder of December with lower holiday loads resulting in off-peak prices in the $55/MWh level. Average November peak weekday regional day-ahead electricity prices were $56.53/MWh at the California-Oregon Border, $49.73/MWh at Mid-Columbia, $55.88/MWh at Palo Verde, $67.79/MWh in Northern California, and $64.06/MWh in Southern California. Average December peak weekday regional day-ahead electricity prices were $55.81/MWh at the California-Oregon Border, $51.27/MWh at Mid-Columbia, $57.30/MWh at Palo Verde, $65.12/MWh in Northern California, and $65.16/MWh in Southern California. Figure 6 shows weekly average day-ahead bilateral electric spot prices through December.

**Figure 6. Weekly Average Western Regional Electric Spot Prices through December**




## II. Real-Time Energy Markets

- *Short price spikes are due to RTMA clearing, and tend to occur during ramping periods, particularly evening ramp between 5:00 and 7:00 p.m.*
- *Longer price spikes are usually due to Miguel and SCIT congestion mitigation, or other contingencies, and may occur at any time, particularly late mornings and also in early evenings.*

Real-time market trends that began in October continued through November and December. The market has generally behaved predictably, with price spikes more frequent than prior to RTMA deployment but shorter in duration. Tables 2 and 3 show volume-weighted average[4] real-time prices, net real-time energy, average loads, and underscheduling, for in-sequence and out-of-sequence/out-of-market (OOS/OOM) dispatches, in November and December.

[4] DMA calculates volume-weighted average prices by weighting hourly prices the CAISO pays to increment generation by the incremental volume, plus the (absolute) hourly prices that generators pay to the CAISO to decrement generation weighted by the decremental volume. This entire quantity is then divided by the incremental volume plus the absolute value of the decremental volume.

## Table 2. Average Real-Time Prices, Net Real-Time Energy, Average Loads, and Underscheduling, for November

| | In-Seq. RT Dispatch | OOS/OOM Dispatch | Total Dispatch | Average Loads and % Underscheduling |
|---|---|---|---|---|
| **PEAK** | $ 62.59 /MWh<br>(67.4) GWh | $ 45.16 /MWh<br>(115.5) GWh | $ 56.66 /MWh<br>(182.9) GWh | 27,830 MW<br>0.3% |
| **OFFPEAK** | $ 43.14 /MWh<br>(14.6) GWh | $ 18.11 /MWh<br>(80.2) GWh | $ 35.35 /MWh<br>(94.8) GWh | 22,130 MW<br>1.3% |
| **ALL** | $ 56.24 /MWh<br>(82.0) GWh | $ 37.09 /MWh<br>(195.7) GWh | $ 49.91 /MWh<br>(277.7) GWh | 25,423 MW<br>0.7% |

## Table 3. Average Real-Time Prices, Net Real-Time Energy, Average Loads, and Underscheduling, for December

| | In-Seq. RT Dispatch | OOS/OOM Dispatch | Total Dispatch | Average Loads and % Underscheduling |
|---|---|---|---|---|
| **PEAK** | $ 55.71 /MWh<br>(118.8) GWh | $ 46.05 /MWh<br>(141.4) GWh | $ 52.37 /MWh<br>(260.2) GWh | 29,140 MW<br>-0.8% |
| **OFFPEAK** | $ 46.41 /MWh<br>(14.7) GWh | $ 34.07 /MWh<br>(89.6) GWh | $ 42.58 /MWh<br>(104.3) GWh | 23,396 MW<br>1.0% |
| **ALL** | $ 52.56 /MWh<br>(133.6) GWh | $ 42.41 /MWh<br>(231.0) GWh | $ 49.17 /MWh<br>(364.6) GWh | 26,731 MW<br>0.0% |

Figures 7 and 8 show daily average real-time prices and net hourly average dispatch volume for both in-sequence and out-of-sequence real-time energy.

## Figure 7. Daily Average Real-Time Market-Clearing Prices, and In-Sequence and OOS/OOM Volumes, for November

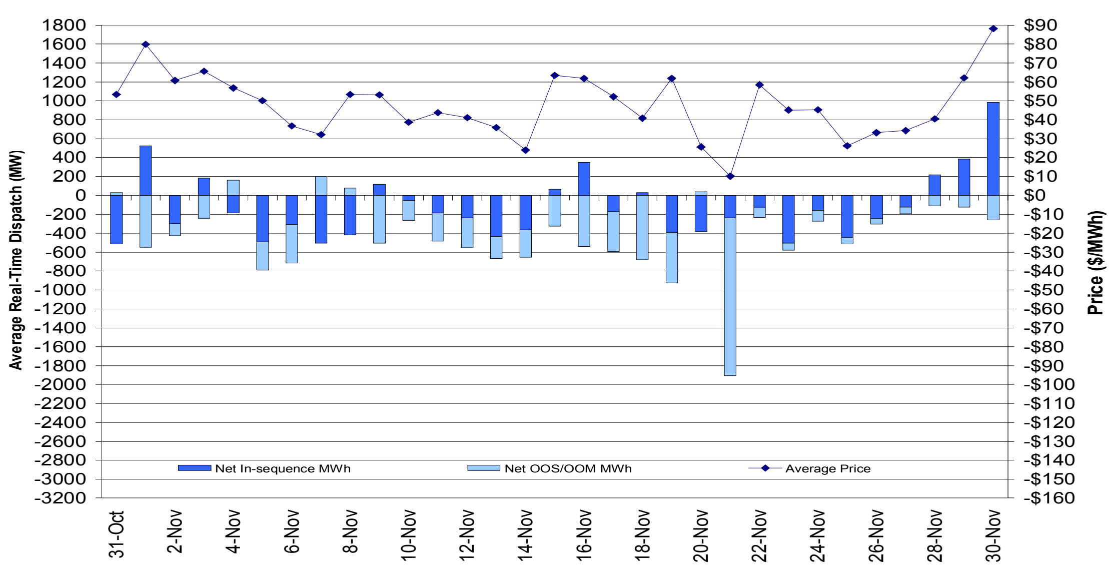
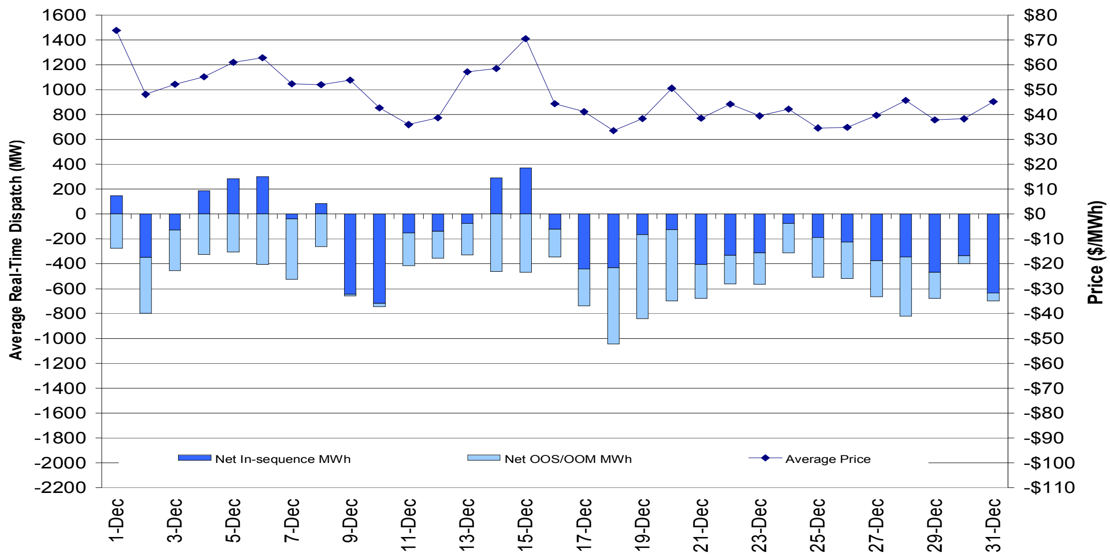


**Figure 8. Daily Average Real-Time Market-Clearing Prices, and In-Sequence and OOS/OOM Volumes, for December**




Price spikes have become more frequent since the implementation of the new RTMA real-time market systems. However, they are also more predictable, arriving at fairly regular times during the day. They also tend to be short in duration. Price spikes in November and December can generally be categorized as follows:

Brief price spikes, lasting five to 15 minutes, have become a regular feature of the RTMA dispatch algorithm, particularly during ramping periods. These occur because RTMA must dispatch several units simultaneously to follow a rapid increase in load. However, once generation is in balance with load, which may happen within one or two five-minute dispatch intervals, the efficient clearing feature of RTMA backs down the generation that had bid the highest prices and ramps up less-costly units, to provide an equal level of power at lower cost. Spikes that occur for this reason may last longer during periods of steep load pull, when real-time balancing may take longer. For example, between 5:00 and 7:00 p.m., load has been increasing at a rate of approximately 2,500 MW per hour, due to evening household heating, appliance use, and holiday lighting. Spikes lasting between five and 30 minutes have occurred during this period on an almost daily basis in December. For a more detailed explanation of this phenomenon, please see the October 2004 Market Analysis Report.

At other times, price spikes are longer in duration, generally lasting 30 to 40 minutes. These usually occur in response to mitigation of intra-zonal congestion at the Miguel Substation east of San Diego, or due to imports constrained by the SCIT Nomogram. They are also caused occasionally by contingencies. These events often occur during the day, particularly in mid-mornings between 8:00 a.m. and 1:00 p.m. (hours ending 9:00-13:00), and during the 5:00-6:00 p.m. load ramp, and occasionally extending later into the evening. Price spikes due to SCIT and

Miguel mitigation are usually limited to SP15, and may occur at any time during an hour of operation.

Figures 9 and 10 show the frequency of price spike intervals in December. The first chart shows the count of spike intervals by hour of day, for both NP15 and SP15. The second chart shows the count of spikes by interval in each hour, again for both NP15 and SP15.

**Figure 9. Count of Spike Intervals by Hour of Day in December**

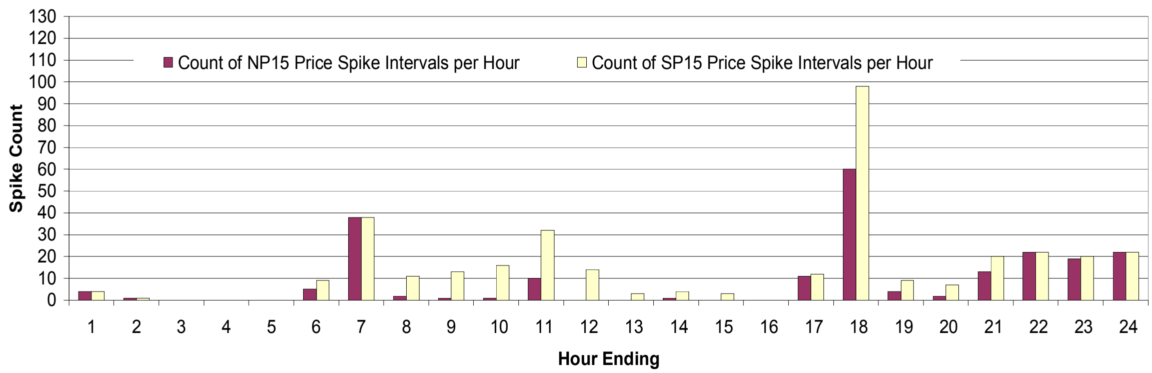
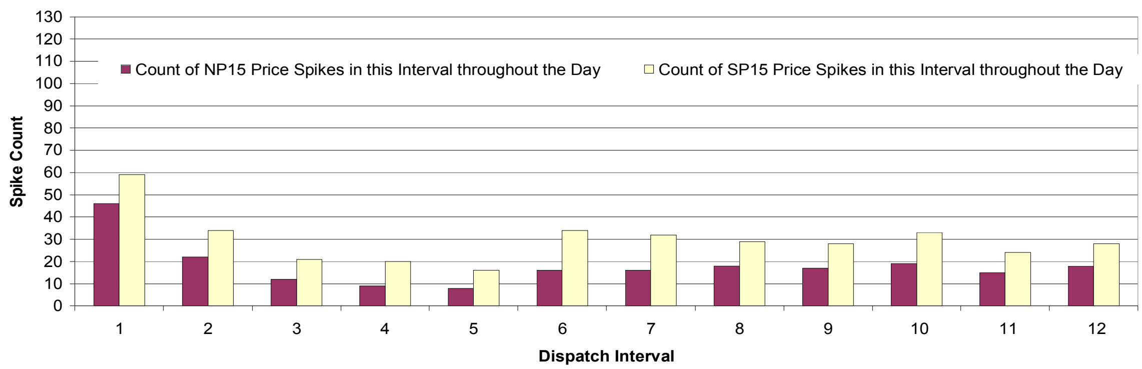
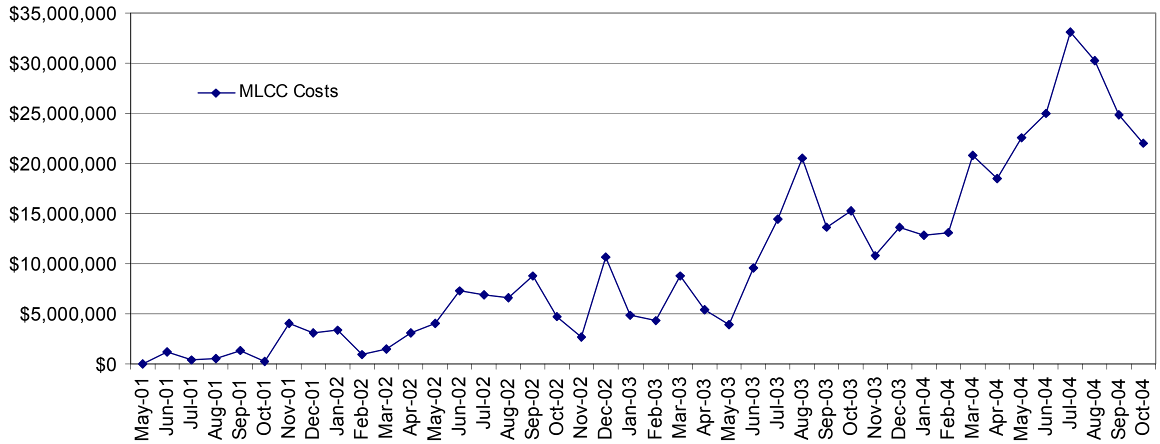



**Figure 10. Count of Spike Intervals by Interval in Each Hour in December**




**Minimum-Load Cost Compensation (MLCC).** Generators that apply to the CAISO for waivers of the Must-Offer Obligation and are denied must remain on-line at minimum load, and are entitled to compensation of minimum-load operating costs. As previously noted, the CAISO denies waivers in large part to retain units needed for SCIT, Miguel, and other mitigation. The Department of Market Analysis is investigating the reasons for the substantial increase in minimum-load costs since mid-2003. The following chart shows MLCC costs through October 2004, the most recent month for which estimates were available at the time of writing.

**Figure 11. Monthly Minimum-Load Cost Compensation through October 2004**[5]




## III. Intra-zonal (within zone) congestion

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

1. MLCC Costs incurred day-ahead as units are constrained so as to be available to provide energy if called upon;

2. RMR Costs incurred in real-time as RMR units are the first to be dispatched to relieve intrazonal congestion; and

3. Redispatch Costs incurred in real-time if the RMR dispatches are not sufficient to alleviate the constraint.

Due to lags in the settlements system, MLCC and RMR costs are only available for analysis after a two month delay. Redispatch costs are readily available and are analyzed as follows.

In November and December incremental congestion volumes moderated slightly, while decremental volumes increased, resulting in a slight net increase in redispatch volume. November and December OOS dispatches resulted in a net cost (re-dispatch premium) of approximately $6.1 and $8.7 million respectively. Total OOS dispatch volume was 332 GWh and 379 GWh (INC plus DEC) and the average redispatch premium was $18.29/MWh and $23.07/MWh respectively. These figures are shown graphically in Figure 12 for recent months.[6]

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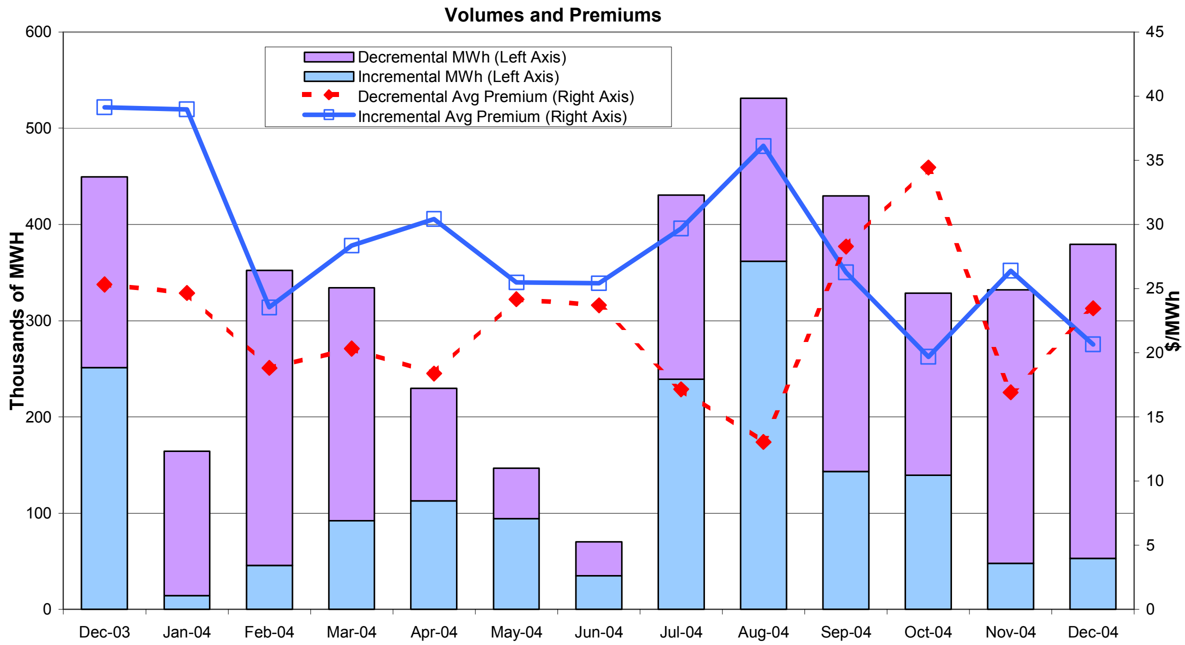
[5] Costs are final through September 2004. October 2004 results are preliminary.

[6] 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 12. Out-of-Sequence Volume and Average Redispatch Premium

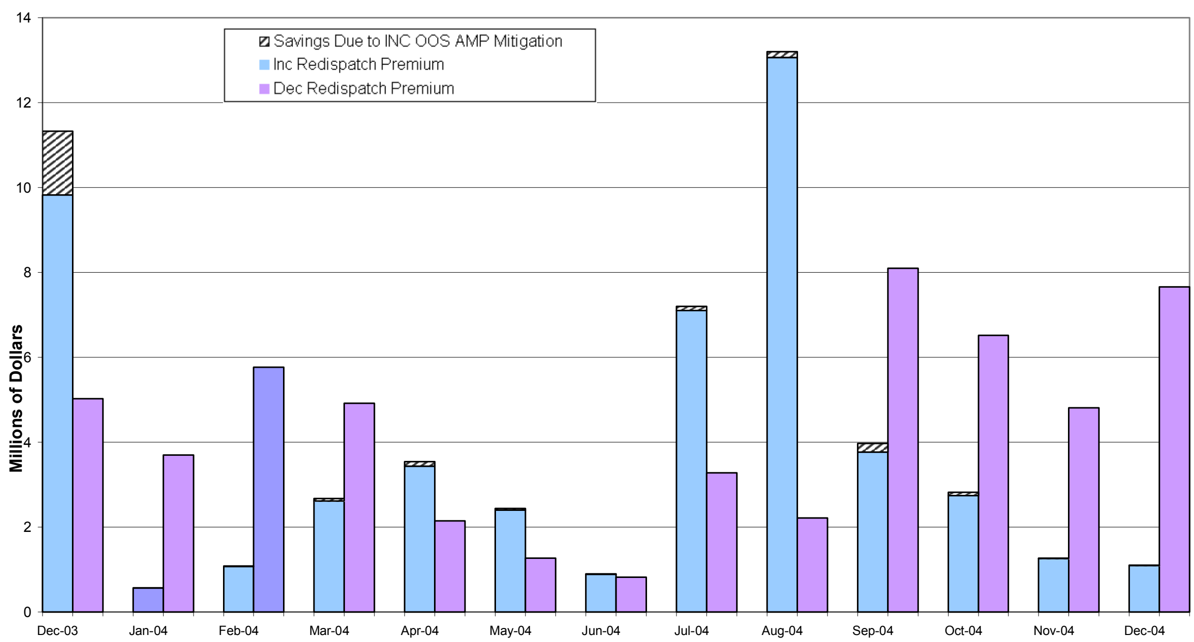


**Incremental OOS Dispatches.**

A total of 47,749 MWh and 52,891 MWh of incremental energy was dispatched out-of-sequence (OOS) by CAISO operators to address intra-zonal congestion in November and December respectively. The average price paid was $77.70/MWh in November ($72.96 in December), and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $1.2 million or $26.40/MWh in November and $1.1 million or $20.66/MWh in December.

Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate savings of $11,477 or approximately 0.9 percent of the incremental redispatch premium in November and $8,564, or approximately 0.8 percent of the incremental redispatch premium in December. All incremental OOS dispatches are subject to mitigation, and Figure 13 shows the re-dispatch premiums for both decremental and incremental congestion as well as the savings due to mitigation of incremental OOS dispatches. As shown in the chart, very little bid mitigation has taken place due to the existing thresholds in AMP for local market power.

**Figure 13. Re-dispatch Premiums and INC OOS Mitigation Savings**

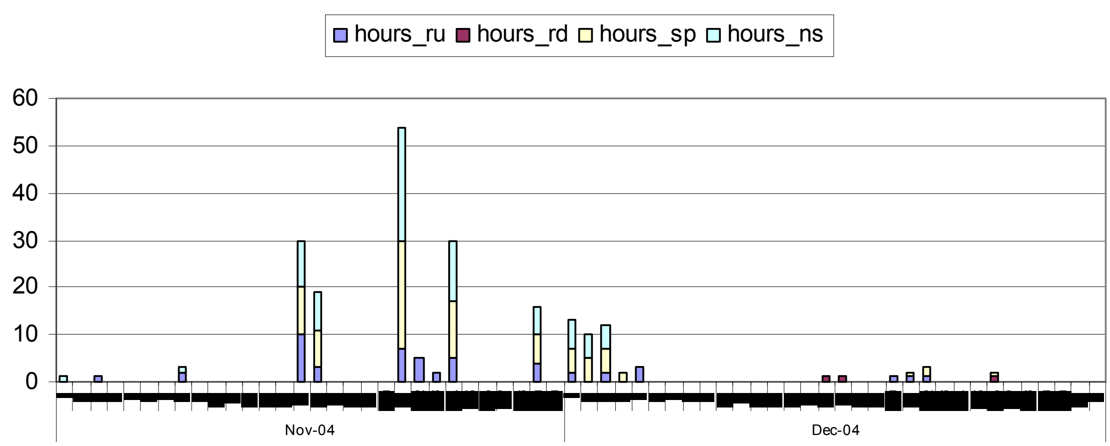



**Decremental OOS Dispatches.** On the decremental side, a total of 284 GWh and 326 GWh were dispatched out of sequence in November and December, respectively. In November the average price paid was $42.07/MWh, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $4.8 million or $16.92/MWh. In December the average price paid was $40.01/MWh and the redispatch premium in excess of the market clearing price (MCP) was approximately $7.7 million, or $23.47/MWh. This energy is settled according to the provisions of the Amendment 50 mitigation measures approved by FERC. As in previous months, almost all of the decremental activity was due to intra-zonal congestion in the San Diego region, which has been exacerbated by the extended outage of the SONGS Unit 3 nuclear generating plant.

## IV. Ancillary Services Markets

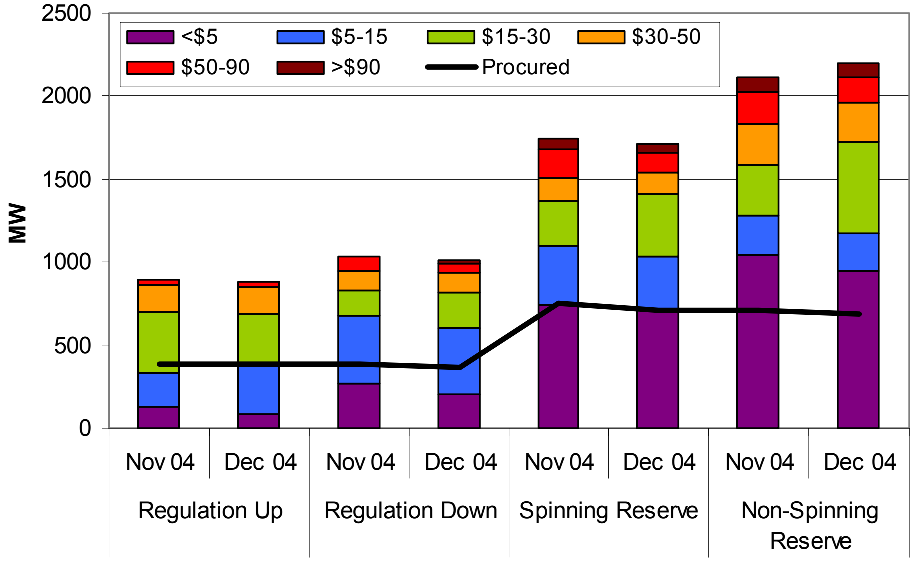
As the generation maintenance season continued into November, periods of significant bid insufficiency in the day-ahead ancillary services markets occurred when grid conditions resulted in CAISO operators procuring operating reserves zonally for reliability reasons. Operating reserve prices frequently spiked during periods when ancillary service market offers were insufficient to meet the CAISO's reserve requirements. However, improving grid conditions allowed operators to procure ancillary services system wide since early December, which alleviated the bid insufficiency and resulting price spikes observed in November. Figure 14 shows the number of bid insufficient hours for each service in the day-ahead market in November and December.

**Figure 14. Number of bid insufficient hours in November and December 2004**




**Market Supply.** Supply of capacity to the A/S markets remained constant in November and December compared to October levels. As expected, planned maintenance and must-offer waiver approvals resulted in lower bid volumes compared to late summer levels. Figure 15 shows bid volumes by price bin in November and December.

**Figure 15. Ancillary Service Day-Ahead Average Bid Volume by Price Bin**




**Market Prices.** Decreased A/S market splitting and bid insufficiency resulted in lower A/S market prices in November compared to October. Overall A/S prices dropped 30 percent from October levels. Overall average prices remained steady between November and December as slightly higher regulation prices were offset by lower non-spin operating reserve prices resulting from system procurement throughout most of December. Table 4 below shows ancillary service product requirements and average prices for November and December.

**Table 4. Average Ancillary Service Requirements and Prices**

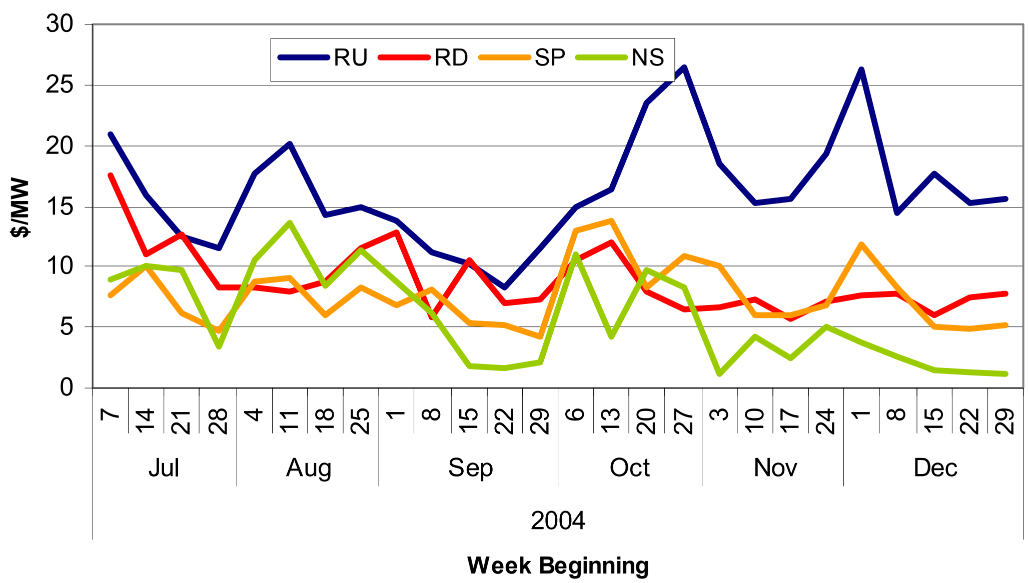
| | Average Required (MW) | | | | Weighted Average Price ($/MW) | | | |
|---|---|---|---|---|---|---|---|---|
| | RU | RD | SP | NS | RU | RD | SP | NS |
| Nov 04 | 388 | 396 | 791 | 755 | $ 17.62 | $ 6.70 | $ 7.31 | $ 3.07 |
| Dec 04 | 389 | 373 | 755 | 735 | $ 18.20 | $ 7.29 | $ 7.41 | $ 2.20 |
| | 0.2% | -6.0% | -4.6% | -2.7% | 3.3% | 8.9% | 1.4% | -28.4% |

Overall A/S procurement decreased 5 percent in November from October levels and another 3.4 percent in December. Table 5 summarizes the A/S procurement and Figure 16 captures price trends over the past six months.

## Table 5. 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 |
| Nov 04 | RU | 387 | 391 | 388 | $ 20.22 | $ 12.47 | $ 17.62 |
| | RD | 404 | 380 | 396 | $ 4.66 | $ 11.03 | $ 6.70 |
| | SP | 838 | 698 | 791 | $ 9.37 | $ 2.35 | $ 7.31 |
| | NS | 796 | 673 | 755 | $ 3.96 | $ 0.97 | $ 3.07 |
| | Total | 2425 | 2142 | 2331 | $ 8.45 | $ 5.26 | $ 7.48 |
| Dec 04 | RU | 396 | 375 | 389 | $ 20.38 | $ 13.59 | $ 18.20 |
| | RD | 379 | 360 | 373 | $ 6.29 | $ 9.40 | $ 7.29 |
| | SP | 791 | 682 | 755 | $ 9.29 | $ 3.05 | $ 7.41 |
| | NS | 772 | 660 | 735 | $ 2.63 | $ 1.21 | $ 2.20 |
| | Total | 2338 | 2077 | 2251 | $ 8.39 | $ 5.43 | $ 7.48 |
| Difference | RU | 9 | -16 | 1 | $ 0.17 | $ 1.11 | $ 0.58 |
| | RD | -25 | -20 | -24 | $ 1.63 | $ (1.63) | $ 0.60 |
| | SP | -47 | -16 | -37 | $ (0.08) | $ 0.70 | $ 0.10 |
| | NS | -24 | -13 | -20 | $ (1.33) | $ 0.24 | $ (0.87) |
| | Total | -87 | -65 | -80 | $ (0.06) | $ 0.17 | $ 0.01 |

## Figure 16. Weekly Weighted Average Ancillary Service Prices




## V. Inter-zonal Congestion Markets

- *Inter-zonal congestion totaled $4.8 million and $3.3 million in November and December, respectively, due largely to transmission constraints on Palo Verde and the California-Oregon Intertie.*
- *Upgrade of Path 15 significantly reduced congestion cost and increased flow between Northern and Southern California.*

Inter-zonal congestion costs totaled $4.8 million in November. The vast majority of all congestion in November was on three paths, namely the Palo Verde branch group (35 percent), Path 15 (25 percent), and the California-Oregon Intertie (COI) (25 percent).

## Table 6. Inter-Zonal Congestion Costs in November, 2004

| 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** | $88,184 | $0 | $0 | $0 | $88,184 | $0 | $88,184 | $0 | $88,184 | 2% |
| **CASCADE** | $7,425 | $0 | -$179 | $0 | $7,247 | $0 | $7,425 | -$179 | $7,247 | 0% |
| **COI** | $1,198,596 | $0 | $10,982 | $0 | $1,209,578 | $0 | $1,198,596 | $10,982 | $1,209,578 | 25% |
| **ELDORADO** | $160,073 | $0 | $36,778 | $0 | $196,851 | $0 | $160,073 | $36,778 | $196,851 | 4% |
| **ELVTHRLY** | $0 | $0 | $0 | $489 | $0 | $489 | $0 | $489 | $489 | 0% |
| **IID-SDGE** | $0 | $0 | $0 | $1 | $0 | $1 | $0 | $1 | $1 | 0% |
| **LUGOGNDRI** | $709 | $0 | $0 | $0 | $709 | $0 | $709 | $0 | $709 | 0% |
| **LUGOMONAI** | $25,441 | $0 | $168 | $0 | $25,610 | $0 | $25,441 | $168 | $25,610 | 1% |
| **LUGOWSWGI** | $960 | $0 | $0 | $0 | $960 | $0 | $960 | $0 | $960 | 0% |
| **MEAD** | $383,145 | $0 | -$18,684 | $0 | $364,461 | $0 | $383,145 | -$18,684 | $364,461 | 8% |
| **N.GILABK4** | $0 | $0 | $0 | $1 | $0 | $1 | $0 | $1 | $1 | 0% |
| **NOB** | $0 | $0 | $5 | $0 | $5 | $0 | $0 | $5 | $5 | 0% |
| **PALOVRDE** | $1,772,213 | $0 | -$92,410 | $0 | $1,679,803 | $0 | $1,772,213 | -$92,410 | $1,679,803 | 35% |
| **PATH15** | $1,226,246 | $0 | -$5,801 | $0 | $1,220,445 | $0 | $1,226,246 | -$5,801 | $1,220,445 | 25% |
| **PATH26** | $0 | $0 | $0 | $6 | $0 | $6 | $0 | $6 | $6 | 0% |
| **SILVERPK** | $2,997 | $0 | -$896 | $0 | $2,101 | $0 | $2,997 | -$896 | $2,101 | 0% |
| **SUMMIT** | $15,815 | $0 | -$6,250 | $0 | $9,565 | $0 | $15,815 | -$6,250 | $9,565 | 0% |
| **Total** | $4,881,806 | $0 | -$76,288 | $497 | $4,805,518 | $497 | $4,881,806 | -$75,791 | $4,806,015 | 100% |

The Palo Verde branch group was congested in the import direction (east-to-west) for 31 percent of all hours in November in the Day-Ahead (DA) market at an average congestion price of $4/MWh, and 8 percent of all hours in the Hour-Ahead (HA), at an average congestion price of $11/MWh. Congestion on Palo Verde in November was due in large part to wheeling energy from the Southwest to Northern California where DA bilateral prices were higher.

Path 15 was congested in the south-to-north direction for 11 percent of all hours in November in the Day-Ahead (DA) market at an average congestion price of $12/MWh, and 4 percent of all hours in the Hour-Ahead (HA), at an average price of $13/MWh. Path 15 experienced almost daily deratings between November 1 and 17 due to maintenance work on Los Banos – Gates lines and several capacitor and line outages/maintenance that connected to Los Banos and Midway substation.

COI was congested for 34 percent of all hours in November in the DA import direction (from Oregon to California) at an average congestion price of $5/MWh, and 31 percent of all hours in the HA import direction at an average price of $13/MWh. COI experienced almost daily deratings throughout the month due to various line/capacitor outages and scheduled line work.

## Table 7. Inter-Zonal Congestion Prices and Frequencies in November 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 |
| BLYTHE _BG | 1 | 0 | $62 | | 0 | 0 | $235 | |
| CASCADE _BG | 29 | 0 | $0 | | 19 | 0 | $0 | |
| COI _BG | 34 | 0 | $5 | | 31 | 0 | $13 | |
| ELDORADO _BG | 9 | 0 | $2 | | 8 | 0 | $8 | |
| LUGOGNDRI_BG | 2 | 0 | $11 | | 0 | 0 | | |
| LUGOMONAI_BG | 2 | 0 | $3 | | 0 | 0 | $30 | |
| LUGOWSWGI_BG | 0 | 0 | $6 | | 0 | 0 | | |
| MEAD _BG | 9 | 0 | $6 | | 6 | 0 | $16 | |
| PALOVRDE _BG | 31 | 0 | $4 | | 8 | 0 | $11 | |
| PATH15 _BG | 11 | 0 | $12 | | 4 | 0 | $13 | |
| PATH26 _BG | 0 | 0 | | | 0 | 0 | | $0 |
| SILVERPK _BG | 2 | 0 | $11 | | 0 | 0 | | |
| SUMMIT _BG | 26 | 0 | $1 | | 18 | 0 | $0 | |

Inter-zonal congestion costs totaled $3.3 million in December with vast majority of congestion on the COI (56 percent) and Palo Verde branch groups (38 percent).

## Table 8. Inter-Zonal Congestion Costs in December 2004

| 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 | | |
| CASCADE | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0% |
| COI | $1,907,397 | $0 | -$51,451 | $0 | $1,855,946 | $0 | $1,907,397 | -$51,451 | $1,855,946 | 56% |
| ELDORADO | $0 | $0 | $29,530 | $0 | $29,530 | $0 | $0 | $29,530 | $29,530 | 1% |
| ELVTHRLY | $0 | $0 | $0 | $18 | $0 | $18 | $0 | $18 | $18 | 0% |
| LUGOMONAI | $0 | $0 | $784 | $0 | $784 | $0 | $0 | $784 | $784 | 0% |
| LUGOWSWGI | $6,771 | $0 | -$1,576 | $0 | $5,195 | $0 | $6,771 | -$1,576 | $5,195 | 0% |
| MEAD | $45,201 | $0 | $58,009 | $0 | $103,210 | $0 | $45,201 | $58,009 | $103,210 | 3% |
| NOB | $41,992 | $0 | -$7,273 | $0 | $34,719 | $0 | $41,992 | -$7,273 | $34,719 | 1% |
| PALOVRDE | $1,278,226 | $0 | -$18,315 | $0 | $1,259,911 | $0 | $1,278,226 | -$18,315 | $1,259,911 | 38% |
| PARKER | $7,166 | $0 | $1,014 | $0 | $8,179 | $0 | $7,166 | $1,014 | $8,179 | 0% |
| SUMMIT | $29 | $0 | -$8 | $0 | $21 | $0 | $29 | -$8 | $21 | 0% |
| Total | $3,286,781 | $0 | $10,714 | $18 | $3,297,495 | $18 | $3,286,781 | $10,732 | $3,297,513 | 100% |

COI was congested for 51 percent of all hours in December in the DA import direction (from Oregon to California) at an average congestion price of $3/MWh, and 37 percent of all hours in the HA import direction at an average price of $8/MWh. COI experienced almost daily deratings throughout December due to various scheduled line and capacitor work. Part of the congestion on

COI was also caused by periodic power circulation from the Pacific DC Intertie (PDCI) due to PDCI testing. PDCI was off-line for scheduled maintenance/upgrade starting September 30 and was returned to commercial service starting December 7. The PDCI transfer capability was gradually increased from 1000 MW on December 7 to around 2000 MW on December 30 and stayed steadily at this level thereafter.

The Palo Verde branch group was congested in the import direction for 11 percent of all hours in the Day-Ahead (DA) market at an average congestion price of $10/MWh, and 7 percent of all hours in the Hour-Ahead (HA), at an average congestion price of $23/MWh. The most significant congestion cost occurred on December 18 when the line was derated due to installation of shunt capacitor.

**Table 9. Inter-Zonal Congestion Prices and Frequencies in December 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 |
| BLYTHE _BG | 0 | 0 | | | 1 | 0 | $104 | |
| CASCADE _BG | 14 | 0 | $0 | | 20 | 0 | $0 | |
| COI _BG | 51 | 0 | $3 | | 37 | 0 | $8 | |
| ELDORADO _BG | 0 | 0 | | | 3 | 0 | $27 | |
| LUGOMONAI_BG | 2 | 0 | $0 | | 0 | 0 | $39 | |
| LUGOWSWGI_BG | 2 | 0 | $5 | | 0 | 0 | | |
| MEAD _BG | 11 | 0 | $1 | | 11 | 0 | $24 | |
| NOB _BG | 8 | 0 | $1 | | 3 | 0 | $29 | |
| PALOVRDE _BG | 11 | 0 | $10 | | 7 | 0 | $23 | |
| PARKER _BG | 2 | 0 | $5 | | 1 | 0 | $2 | |
| SUMMIT _BG | 17 | 0 | $0 | | 6 | 0 | $0 | |

No congestion occurred in December on Path 15 due in part to the completion of the Path 15 upgrade. The upgrade increased the Path 15 south-to-north transfer capability to 5,400 MW from 3,900 MW. Upgrade of Path 15 started commercial use at 12:01am on December 22 in the HA market and the DA market use began on December 23. The upgrade of Path 15 significantly reduced congestion cost and increased flows on the path especially during peak hours. The average daily maximum final flow was 3,154 MW from December 22 to December 31 (all in the south-to-north direction), a 40 percent increase when compared to the average daily maximum flow between December 1 and 21.

## VI. Firm Transmission Rights Market

**FTR Scheduling.** FTRs can be used to hedge against high congestion prices and to provide scheduling priority in the day-ahead market. Many of the FTRs are owned by Southern California Edison Company and municipal utilities. Table 10 shows the extent to which FTRs were scheduled on the various paths connecting the CAISO Control Area to neighboring control areas.

### Table 10. FTR Scheduling Statistics - 2004[7]

| Direction | Branch Group | MW FTR Auctioned | Avg MW FTR Sch | Max MW FTR Sch | Max Single SC FTR Scheduled | % FTR Schedule - Dir |
|---|---|---|---|---|---|---|
| IMP | BLYTHE _BG | 168 | 100 | 167 | 167 | 59% |
| IMP | ELDORADO _BG | 536 | 522 | 536 | 536 | 97% |
| IMP | IID-SCE _BG | 600 | 464 | 477 | 457 | 77% |
| IMP | LUGOMKTPC_BG | 247 | 13 | 16 | 16 | 5% |
| IMP | MEAD _BG | 624 | 19 | 44 | 25 | 3% |
| IMP | PALOVRDE _BG | 1021 | 358 | 570 | 400 | 35% |
| IMP | SILVERPK _BG | 10 | 10 | 10 | 10 | 100% |
| IMP | VICTVL _BG | 921 | 31 | 50 | 50 | 3% |
| EXP | LUGOMKTPC_BG | 247 | 3 | 3 | 3 | 1% |
| EXP | PATH26 _BG | 1314 | 436 | 813 | 443 | 33% |

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

**FTR Revenue per Megawatt.** FTR revenues increased on some paths and decreased on others between October and November. The most congested branch groups COI and Palo Verde, accounted for the bulk of revenues, with Path 15 also incurring revenues. Table 11 shows FTR revenue per MW for each branch group in 2004.

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

## Table 11. FTR Revenue Per MW ($/MW) - 2004[8]

| Direction | Branch Group | Net $/MW FTR Rev | - | - | - | - | - | - | - | - | Cumm Net $/MW FTRREV | Pro Rated NET $/MW FTRREV | FTR Auction Price |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | | | |
| IMPORT | BLYTHE | 2,791 | 5,540 | 433 | 0 | 7 | 736 | 332 | 992 | 0 | 10,830 | 14,440 | 8,759 |
| IMPORT | COI | 697 | 5,185 | 16,985 | 2,876 | 1,823 | 8,939 | 6,551 | 7,652 | 7,084 | 57,792 | 38,528 | 26,964 |
| IMPORT | ELDORADO | 0 | 408 | 10 | 0 | 0 | 400 | 136 | 156 | 19 | 1,128 | 1,505 | 45,169 |
| IMPORT | LUGOGNDRI | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 176 | 0 | 176 | 235 | 63,374 |
| IMPORT | LUGOIPPDC | 9 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 9 | 12 | 81,579 |
| IMPORT | LUGOMKTPC | 0 | 0 | 0 | 0 | 7 | 224 | 764 | 0 | 0 | 995 | 1,327 | 99,784 |
| IMPORT | LUGOMONAI | 0 | 0 | 0 | 0 | 0 | 408 | 216 | 99 | 3 | 725 | 967 | 117,989 |
| IMPORT | LUGOTMONA | 0 | 0 | 576 | 0 | 0 | 24 | 0 | 0 | 0 | 600 | 800 | 136,194 |
| IMPORT | LUGOWSTWG | 0 | 2 | 0 | 1 | 52 | 2,036 | 0 | 0 | 0 | 2,090 | 2,787 | 154,399 |
| IMPORT | LUGOWSWGI | 0 | 0 | 0 | 0 | 0 | 888 | 422 | 52 | 364 | 1,726 | 2,301 | 172,604 |
| IMPORT | MEAD | 1,223 | 1,168 | 634 | 464 | 238 | 930 | 1,114 | 2,386 | 849 | 9,006 | 12,008 | 190,809 |
| S-N | NOB | 458 | 2,477 | 26,077 | 5,080 | 1,382 | 1,734 | 0 | 0 | 638 | 37,845 | 25,230 | 209,014 |
| IMPORT | PALOVRDE | 2,666 | 19,474 | 3,159 | 12,220 | 10,508 | 21,496 | 11,321 | 7,791 | 6,645 | 95,280 | 63,520 | 227,219 |
| IMPORT | PARKER | 115 | 15 | 0 | 5 | 6 | 178 | 0 | 0 | 252 | 571 | 761 | 245,424 |
| N-S | PATH15 | 0 | 98 | 100 | 25 | 1,435 | 2,983 | 15,525 | 3,759 | 0 | 23,925 | 15,950 | 263,629 |
| IMPORT | SILVERPK | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 176 | 0 | 181 | 241 | 281,834 |
| EXPORT | NOB | 0 | 0 | 0 | 910 | 522 | 0 | 0 | 0 | 0 | 1,433 | 1,910 | 300,039 |

* 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.

[8] FTRs on these paths were awarded to municipal utilities that converted their lines to the ISO, and therefore, were not released in the primary auction.

**Table 12. FTR Primary Auction (New FTR Assignments)**

| Branch Group | Direction | Owner Id | Start Auction Dt | End Auction Dt | Pa Auc Qty | New Ftr Qt | Tot Ftr Qt | Auc Price |
|---|---|---|---|---|---|---|---|---|
| BLYTHE | EXP | CISO | 1-Jan-05 | 31-Mar-05 | 0 | 43 | 43 | 28 |
| COI | EXP | BPEC | 1-Jan-05 | 31-Mar-05 | 0 | 50 | 50 | 28 |
| COI | EXP | CEPL | 1-Jan-05 | 31-Mar-05 | 0 | 300 | 300 | 28 |
| COI | EXP | MSCG | 1-Jan-05 | 31-Mar-05 | 0 | 390 | 390 | 28 |
| COI | EXP | PWRX | 1-Jan-05 | 31-Mar-05 | 0 | 200 | 200 | 28 |
| COI | IMP | BPEC | 1-Jan-05 | 31-Mar-05 | 0 | 50 | 50 | 2978 |
| COI | IMP | CRLP | 1-Jan-05 | 31-Mar-05 | 0 | 100 | 100 | 2978 |
| COI | IMP | PWRX | 1-Jan-05 | 31-Mar-05 | 0 | 562 | 562 | 2978 |
| COI | IMP | SDG3 | 1-Jan-05 | 31-Mar-05 | 0 | 88 | 88 | 2978 |
| COI | IMP | TEMU | 1-Jan-05 | 31-Mar-05 | 0 | 150 | 150 | 2978 |
| PATH15 | IMP | CISO | 1-Jan-05 | 31-Mar-05 | 0 | 350 | 350 | 1826 |
| PATH15 | IMP | CRLP | 1-Jan-05 | 31-Mar-05 | 0 | 100 | 100 | 1826 |
| PATH15 | IMP | SCE1 | 1-Jan-05 | 31-Mar-05 | 0 | 408 | 408 | 1826 |
| PATH15 | IMP | TEMU | 1-Jan-05 | 31-Mar-05 | 0 | 50 | 50 | 1826 |
| PATH26 | EXP | CRLP | 1-Jan-05 | 31-Mar-05 | 0 | 62 | 62 | 995 |
| PATH26 | EXP | MRNT | 1-Jan-05 | 31-Mar-05 | 0 | 31 | 31 | 995 |
| PATH26 | EXP | MSCG | 1-Jan-05 | 31-Mar-05 | 0 | 18 | 18 | 995 |
| PATH26 | EXP | PWRX | 1-Jan-05 | 31-Mar-05 | 0 | 62 | 62 | 995 |

## VII. Issues under Review

DMA continues to support the ISO's efforts in the CPUC's Resource Adequacy workshop process.

DMA also continues to contribute to the economic evaluation of the Palo Verde-Devers 2 (PVD2) upgrade project. The PVD2 proposal would add a second line to connect the Los Angeles load area to generation in Arizona, increasing the transmission capacity of the southernmost corridor of Path 49. DMA compared the PVD2 project to East-of-River (EOR) 9,000, a similar project of upgrades to the northern transmission corridor, and sponsored by the Los Angeles Department of Water and Power and the Salt River Project in Arizona. The study found that the two projects are complementary. In the upcoming weeks, DMA will also evaluate increasing West-of-River (WOR, Path 46) transmission limits and their effects on the PVD2 upgrade project.