California Independent
System Operator

CALIFORNIA ISO

Memorandum

To: ISO Board of Governors

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

cc: ISO Officers, ISO Board Assistants

Date: November 5, 2004

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

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

Executive Summary

High loads due to fairly hot weather throughout the state, particularly in southern California, contributed to a record peak load of 45,597 megawatts (MW) on the afternoon of September 8. The previous all-time record was set on August 11 of this year. Two days later, the SP15 zone experienced a record peak of 25,869 MW. CAISO average loads resumed their pattern of 3 to 4 percent growth from year-to-year following a temporary plateau during the months of July and August 2004.

Unusually high levels of imported energy into the CAISO control area resulted in congestion on the major transmission interties from the Southwest and Pacific Northwest. Inter-zonal congestion costs in September totaled approximately $8.8 million, the highest monthly total since the summer of 2002. Much of this was due to congestion between Arizona and southern California. During the peak load period of September 7-10, moderate loads in the southwest allowed unusually high levels of energy to be imported into southern California.

September marks the second month of locational procurement in the CAISO ancillary services markets. This has frequently resulted in insufficient bids available to meet the CAISO's day-ahead market requirements for SP15. Amendment 60 was implemented in part to increase supply into the ancillary services markets by allowing units committed by the CAISO via the must-offer obligation to participate in the ancillary services markets without forfeiting their minimum load cost compensation (MLCC). To further help the participation of these units in the ancillary services markets, the must offer timeline was moved forward prior to the deadline for submitting day-ahead A/S bids on September 2 for market transactions on September 3. The Amendment 60 market changes have resulted in more supply in both the day-ahead and hour-ahead ancillary service markets. Average ancillary service prices dropped 60 percent from August levels despite a sharp increase in SP15 A/S requirements to cover record loads. The facts that the September record loads were due to a brief heat wave and that the fall unit maintenance season had yet to begin led to lower overall prices.

On October 1, Phase 1B of the Market Redesign and Technology Upgrade (MRTU, previously known as MD02) was implemented, replacing the CAISO's dispatch methodology with fully automated dispatch algorithm software designed to improved reliability and lower costs through economic dispatch of generation resources. Since going live, Phase 1b has had several noticeable impacts on the market. Real-time energy costs and price volatility increased during the first week of implementation, as CAISO operators and engineers resolved technical issues with the software and operation. However, higher real-time prices were also the result of significant resource outages including San Onofre Nuclear Generating Station (SONGS) Unit 3, Palo Verde Unit 3 and the Pacific DC Intertie that led to increased transmission congestion into southern California. Since then, prices have moderated considerably, particularly within SP15. See the issues under review section below for further discussion on MRTU Phase 1B implementation and market impacts.

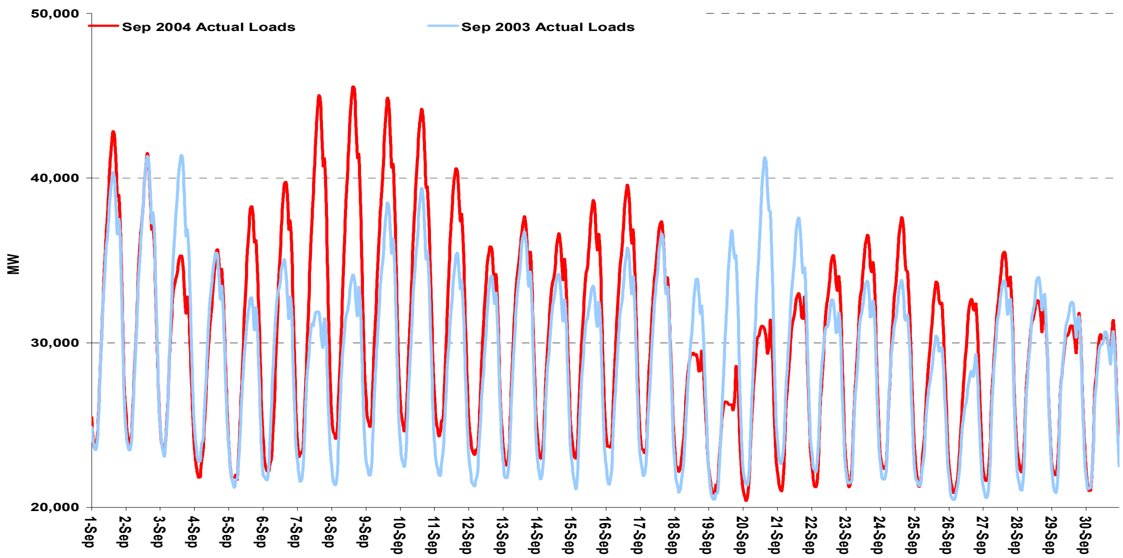
I. Trends Affecting Electricity Market Demand and Supply

- *New all-time peak load*
- *Imports kept transmission capacity fully loaded*

Loads. Moderately high temperatures across California contributed to record high loads September 7 through 10. On September 8, between 3:00 and 4:00 p.m. (hour ending 16:00), the CAISO control area load peaked at 45,597 MW, approaching the all-time record peak load of 45,884 MW, set July 12, 1999, when the control area also included the Sacramento Municipal Utility District (SMUD).[1] Temperatures were in the low 100-degree range across most of the Central Valley and southern California on September 8. Two days later, on September 10, 2004, between 3:00 and 4:00 p.m. (HE 16:00), SP15 load reached a new all-time peak of 25,743 MW due to temperatures across Southern California that were fairly high, although not at levels typically seen on a peak day. Figure 1 compares actual hourly average loads in 2004 and 2003.

[1] The 9/8/04 peak load of 45,597 MW is an instantaneous load that occurred in the middle of the hour. Data from 1999 are available only on a top-of-hour basis. The actual instantaneous peak load on 7/12/99 may have been above 45,597 MW.

Figure 1. Comparison of Actual Loads in September: 2004 v. 2003



In September, the trend toward load growth resumed, after year-to-year loads had leveled off in July and August. This trend is influenced in part by the peak load period between September 7 and 10. The increase in load is driven in large part by the increase in population, primarily in San Bernardino and Riverside Counties. Since approximately October 2003, the CAISO has experienced year-to-year load growth of approximately 4 percent. Average load in September 2004 was 30,081 MW, or 3.4 percent above that in September 2003. Table 1 shows same-month year-to-year changes in average hourly load, average daily peak load, average daily trough (minimum) load for each month, and monthly peak loads for each month. The average daily trough serves as an indicator of non-weather related load growth, as loads tend to vary less with weather during off-peak nighttime hours.

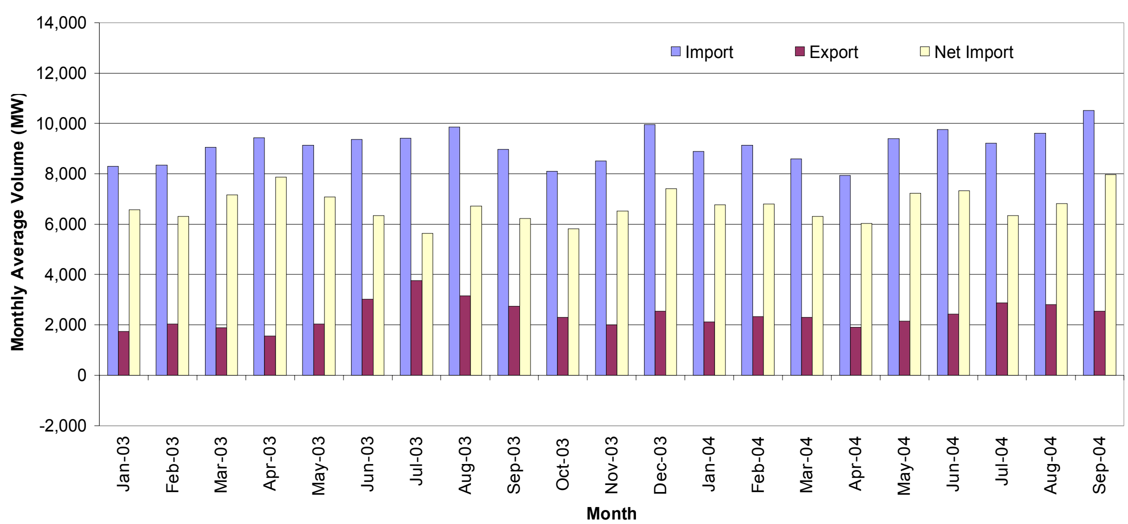
Table 1. Year-to-Year Growth in Load: Monthly Indices through September 2004

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
October-03	5.4%	7.0%	2.6%	3.7%
November-03	-0.2%	1.0%	-0.8%	0.2%
December-03	2.8%	3.1%	1.5%	2.7%
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%

Notes: Through 7/10/03: Actual loads at top of hour. Since 7/11/03: Hourly average loads.

Imports and Exports. When California experienced its peak load during September 7-10, transmission was fully loaded on key paths in the import direction, as generation in typically hot areas such as Arizona actually had capacity to spare, and sold power to California. Generation in the Pacific Northwest also helped to meet load in California. Mild weather outside of California led to uncharacteristically high levels of imports from both the northwest and the southwest during this period. Some scheduled imports were curtailed in real time for mitigation of unscheduled flows. Figure 2 shows average imports, exports, and net imports into the CAISO control area by month in peak hours.

Figure 2. Monthly Average Peak-Hour Imports, Exports, and Net Imports through September



The robust supply of imports also contributed to the highest monthly inter-zonal congestion costs since 2002, totaling approximately $8.8 million in September. Please see the section below on inter-zonal congestion for additional details.

II. Real-Time Energy Market

- *Price spikes during load peaks on September 8-10*
- *Miguel-related intrazonal congestion costs were nearly $6 million*

The proportion of out-of-sequence (OOS) and out-of market (OOM) dispatches to in-sequence dispatches in the CAISO's real-time balancing energy ex-post price (BEEP) auction market remained high in September. OOS/OOM incremental and decremental dispatches respectively were approximately 40 and 43 percent of all real-time energy procured. However, OOS/OOM dispatches in September had a lower average cost of energy than in-sequence dispatches at the market-clearing price (MCP).[2]

Real-time incremental (INC) prices averaged $64.64 per megawatt-hour (MWh) in September, with 359 gigawatt-hours (GWh) procured, compared to $67.94/MWh in August, with 380 GWh procured. Decremental (DEC) prices averaged $23.56/MWh in September, with 676 GWh procured, compared to $30.95/MWh in August with 662 GWh procured. Table 2 shows average real-time INC and DEC energy prices and total energy procured in sequence (BEEP), out of sequence and/or out of market (OOS/OOM), and overall, for peak, off-peak, and all hours. It also shows average system loads and the percentage of underscheduling.

Table 2. Real-Time Prices and Volumes in September [3]

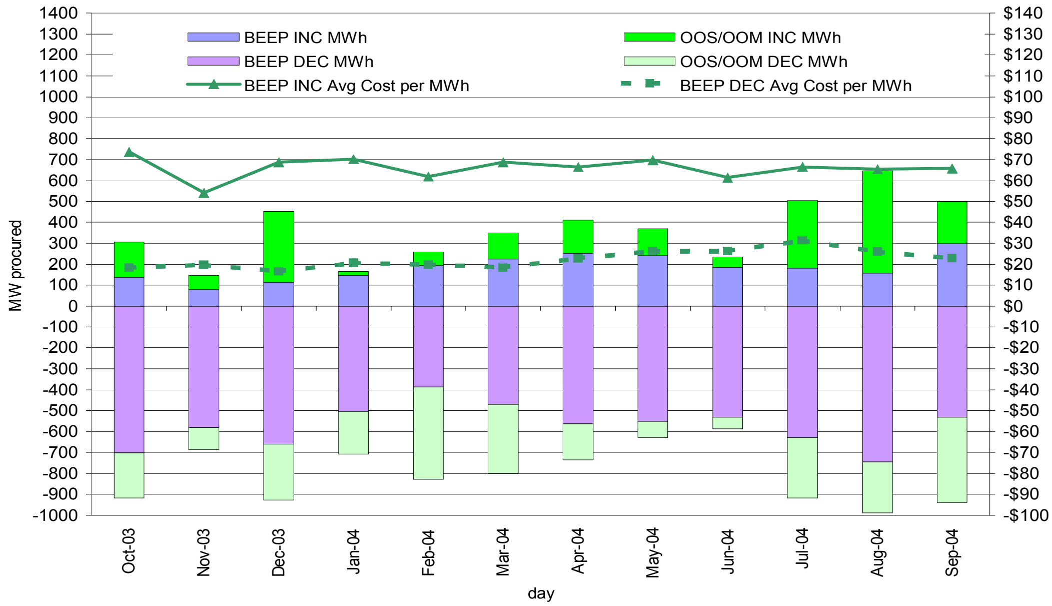
	Avg. BEEP Price and Total Volume		Avg. OOS/OOM Price and Total Volume		Overall Avg. Real-Time Price and Total Volume		Avg. System Loads (MW) and Pct. Underscheduling
	Inc	Dec	Inc	Dec	Inc	Dec	
Peak	$ 71.11	$ 25.78	$ 64.07	$ 25.08	$ 68.24	$ 25.43	33,085 MW
	159 GWh	288 GWh	109 GWh	281 GWh	269 GWh	569 GWh	0.8%
Off-Peak	$ 50.42	$ 13.81	$ 59.62	$ 12.06	$ 54.02	$ 13.61	24,072 MW
	55 GWh	95 GWh	36 GWh	12 GWh	91 GWh	107 GWh	1.3%
All Hours	$ 65.77	$ 22.82	$ 62.97	$ 24.52	$ 64.64	$ 23.56	30,081 MW
	214 GWh	383 GWh	145 GWh	294 GWh	359 GWh	676 GWh	0.9%

Figure 3 shows monthly average volumes for in-sequence BEEP, and OOS/OOM incremental and decremental energy, as well as average in-sequence BEEP prices, through September.

[2] An OOS dispatch cannot represent a lower cost to load in any one particular interval; however, in this case the OOS energy was procured in intervals in which costs were lower than those in which in-sequence energy was procured.

[3] Because these tables report OOS energy, they are not comparable to similar tables shown in previous Market Analysis Reports, up to the report dated July 23, 2004. Real-time imbalance may differ from deviation between schedule and actual load due to units on minimum load, real-time uninstructed deviations, unaccounted-for energy, etc.

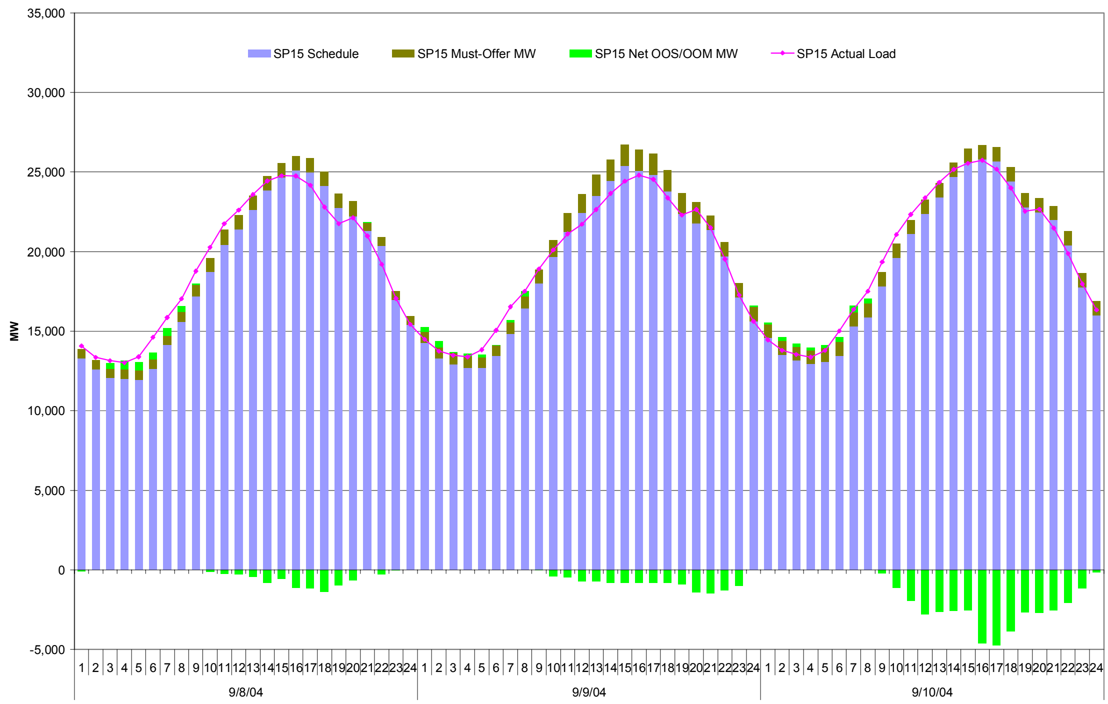
Figure 3. Monthly Average Real-Time In-Sequence and OOS/OOM Volumes, and In-Sequence Market Clearing Prices, through September



Energy Schedules and Must-Offer Commitment during Peaks. Because the September 7-10 high loads were largely anticipated, scheduling coordinators were able to submit forward schedules of power that were sufficient or nearly sufficient to meet load. While schedules were approximately 1,000 MW short of load during the peak on September 7, schedules exceeded load during the peaks on September 8-10. Within SP15, schedules were aligned much more tightly to load, coming within 75 MW of actual load on September 10.

Pursuant to the "Must-Offer" Obligation, the CAISO held on line 1,132 MW of minimum load generation above schedules, representing approximately 4,100 MW of available capacity during the peak hours of September 8. Of this, 900 MW of minimum-load generation representing 2,816 MW of available capacity was located within SP15. By September 10, the CAISO had further shifted its Must-Offer unit commitment to resources within SP15, so that 877 of 951 MW, representing 3,441 available MW, were deliverable to SP15. However, the available Must-Offer energy on all these days, and on September 10 in particular, was offset by significant OOS decremental dispatches needed to mitigate intra-zonal congestion at the Miguel substation. As a result, the CAISO had fewer than 100 MW to spare on September 10. Figure 4 compares actual load within SP15 to schedules, minimum-load Must-Offer energy, and net OOS dispatches within SP15, for September 8-10.

Figure 4. Actual Load v. Hour-Ahead, Must-Offer, and Net Real-Time OOS Energy within SP15: September 8-10, 2004

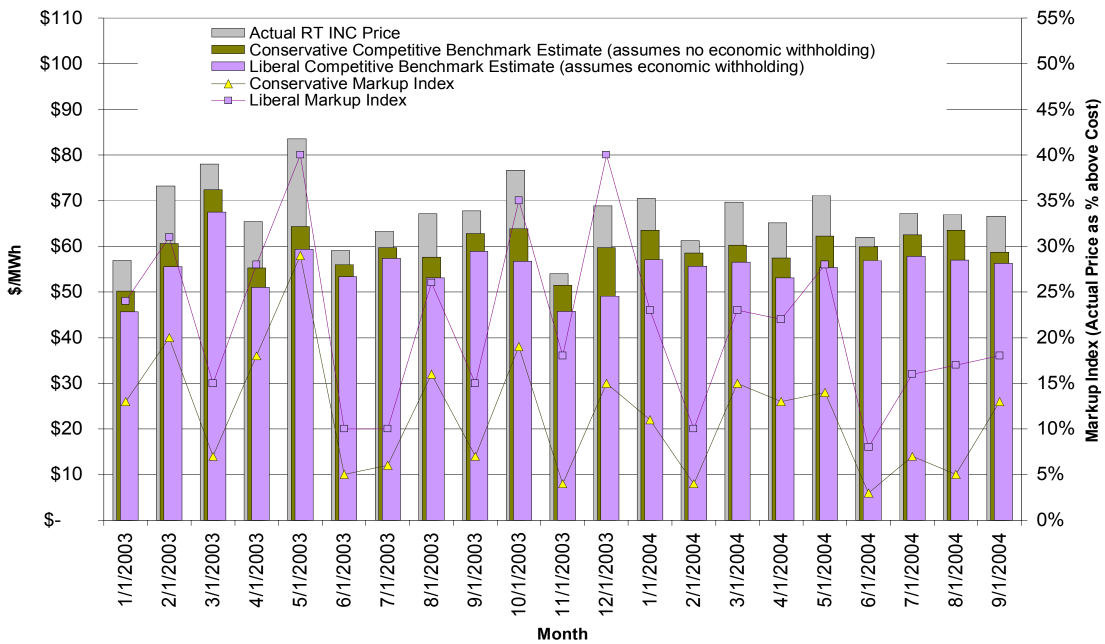


Real-time Market Competitiveness. The real-time price-to-cost markup is an indicator of the competitiveness of the real-time market. The Department of Market Analysis calculates this index as a comparison of the actual incremental market-clearing price to a competitive benchmark price. As discussed in the Market Analysis Report dated February 19, 2004, the Department of Market Analysis now reports two indices of markup to present a range of the competitiveness of the real-time market. One index assumes no economic withholding; it assumes that high-priced bids in excess of the market clearing price reflect high costs. This produces a higher estimate of the competitive price and results in a lower estimate of potential markup. The other index accounts for economic withholding by substituting estimated marginal cost-based bids for bids in excess of the market clearing price. This produces a lower estimate of the competitive price and a higher estimate of potential markup.

The price-to-cost markup in incremental balancing energy was slightly higher in September, in the range of 13 to 18 percent for the two indices. The five highest markup hours accounted for over 25 percent of the monthly total markup of approximately $2.3 million.[4] Figure 5 compares monthly average prices to the two competitive benchmarks, and shows the two markup indices through September.

[4] Unless specified, liberal markup methodology is used.

Figure 5. Real-Time Price to Cost Markup
Actual Real-Time Incremental Energy Prices v. Competitive Benchmark Prices: January 2003 through September 2004



Price Spikes. The only significant price spikes in September occurred during the peak load periods on September 8 and 10 within SP15.

On September 8, between 3:00 and 6:00 p.m. (HE 16:00 through 18:00), the market clearing price ranged between $165 and $175/MWh, and was set by a high-cost gas turbine resource within SP15. This resource is emission-constrained and generally operates only when prices exceed $150. The resource's reference level at this time was approximately $107/MWh and its estimated marginal cost was approximately $116/MWh. For the three hours that this unit was marginal, it was metered at approximately 87.7 percent of the 41 MWh it was expected to generate. The real-time in-sequence dispatch during this period averaged 1,218 MW. These three hours accounted for approximately 8.1 percent of the monthly total markup above competitive benchmark costs.

The same unit set the price at $165/MWh on September 10, between 2:20 and 4:00 p.m. Immediately thereafter, two other steam units owned by the same independent energy producer jointly set the price at $175/MWh until 5:20 p.m., and then at $115/MWh until 5:40 p.m. These were operating in ranges such that their reference levels were approximately $92 and $95/MWh, respectively, and their estimated marginal costs were both in the mid-$50/MWh range. During this period, these units either adhered to their expected energy production or exceeded it. The real-time in-sequence dispatch to SP15 during this period averaged 1,988 MW needed to meet high loads and to counter OOS decremental dispatches for Miguel congestion and other reasons that reached as high as 5,000 MW. Hours ending 15:00 through 18:00 contributed 19.8 percent of the monthly total markup above competitive baseline costs.

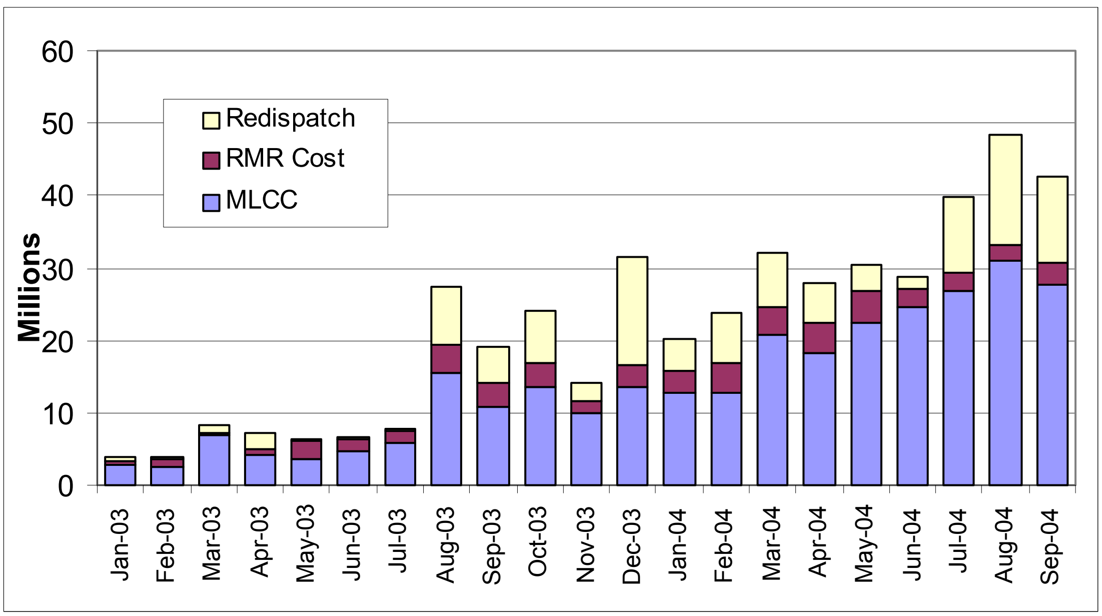
Real-Time Intra-zonal Congestion Management. Overall intra-zonal (within zone) congestion costs decreased from August to September primarily due to lower costs associated with ongoing maintenance work at the Sylmar substation. Total intrazonal congestion costs were nearly $42 million in September, down from nearly $50 million in August.

Figure 6 below shows the total intrazonal congestion costs by month. Total intrazonal congestion costs consist of three elements:

1. The minimum load cost compensation (MLCC) cost of constraining units online for intrazonal congestion mitigation,
2. The real-time RMR cost of dispatching RMR units to mitigate intrazonal congestion, and
3. The real-time out-of-sequence (OOS) redispatch costs of dispatching non-RMR units to solve intrazonal congestion.

As shown in the figure below, there has been a steady upward progression of these costs since 2003.

Figure 6. Monthly Total Intrazonal Congestion Costs

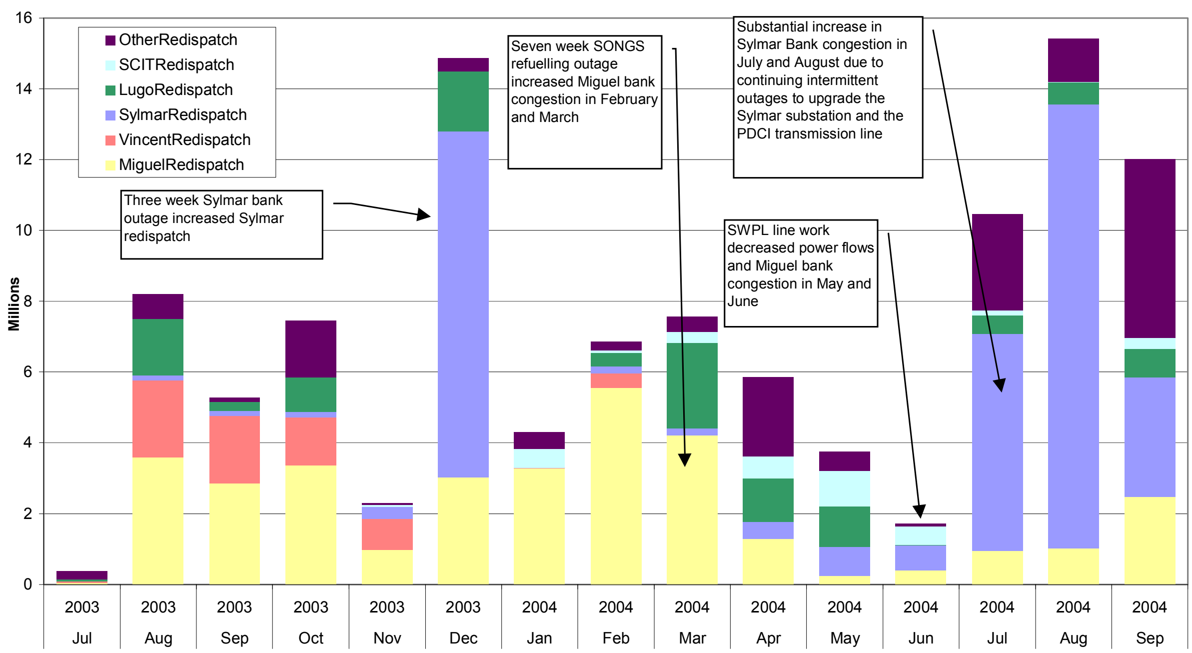


Re-dispatch Costs

The primary reason for incremental OOS dispatches continued to be constraints at the Sylmar substation due to ongoing maintenance work (76 percent of incremental re-dispatch costs). Lugo (5 percent) and other transmission and substation related costs made up the balance of the month's re-dispatch costs.

Miguel re-dispatch costs increased in September and comprised 72.2 percent of all decremental re-dispatch costs[5]. This was partly due to high southern California loads in early September and the refueling outage of the San Onofre Nuclear Generating Station Unit 3 (SONGS3) in late September. SONGS 3 is expected to be out of service until late December or early January. The SONGS outage will have a significant and negative effect on Miguel bank congestion during this period. The balance of the decremental intra-zonal costs were due to Sylmar (6 percent), Lugo (7 percent), SCIT (3 percent) and other transmission related outages. Figure 7 shows the intra-zonal congestion re-dispatch costs by month and location.

Figure 7. Monthly Total Congestion Costs by Location and/or Cause

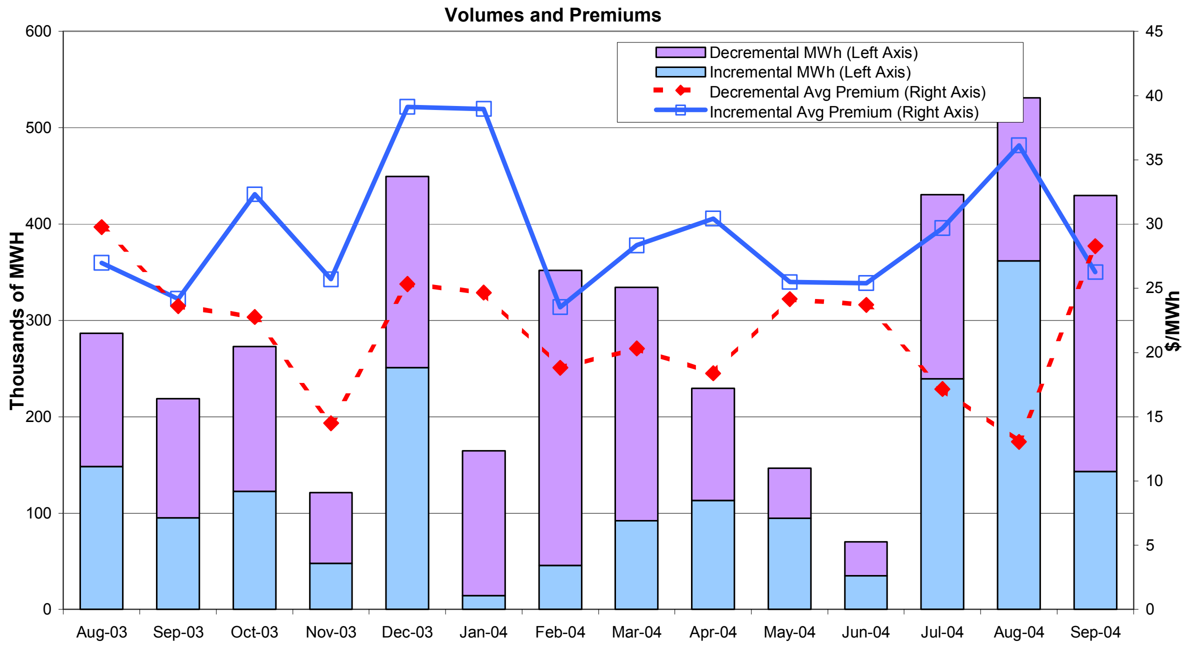


Overall, September intra-zonal congestion OOS dispatches resulted in a net cost (re-dispatch premium) of approximately $11.8 million compared to $15.2 million in August. Total congestion OOS dispatch volume was 430 GWh (INC plus DEC), and the average re-dispatch premium was $27.62/MWh. Miguel was the most costly constraint (approximately 50 percent of total re-dispatch costs), followed by Sylmar (28 percent). Figure 8 illustrates these amounts for recent months.[6]

[5] Due to data issues, in September only, approximately 80 percent of the costs associated with the 'OTHER' category are in fact also due to Miguel. Thus the Miguel figure consists of the 29 percent of costs clearly identified as such and the 43.2 percentage points of 'OTHER' costs, making a grand total of 72.2 percent.

[6] Congestion net cost or re-dispatch 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.

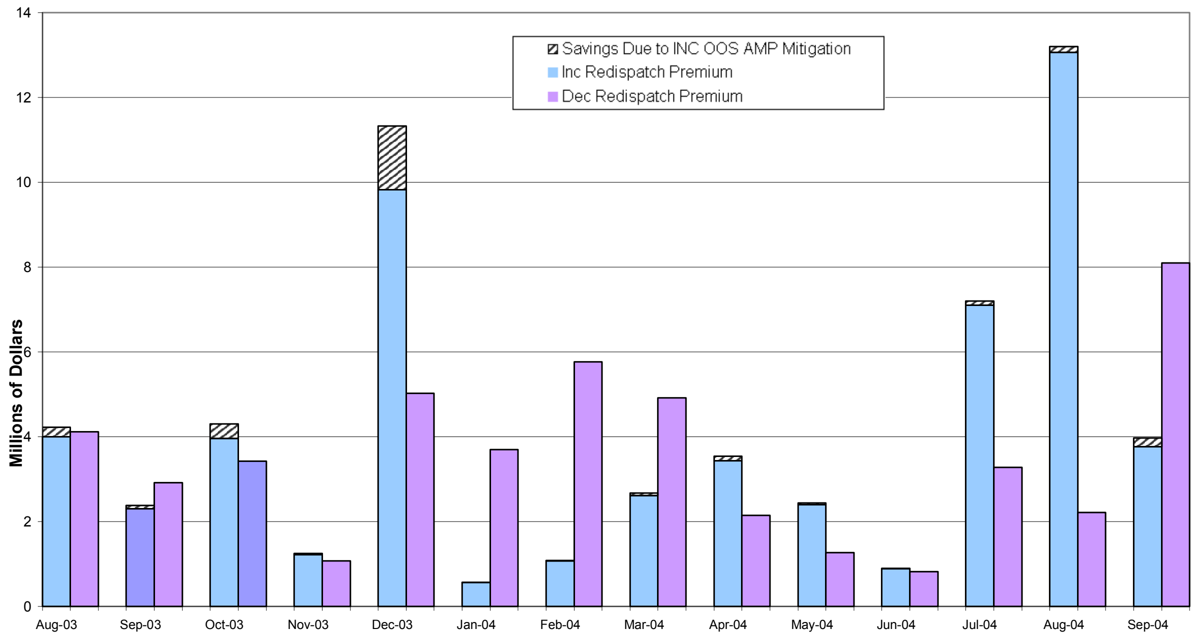
Figure 8. Intrazonal Congestion Volume and Average Re-dispatch Premium



Incremental Intra-zonal Congestion Dispatches. CAISO operators dispatched 143 GWh of incremental energy in September to mitigate intra-zonal congestion. The average price paid was $63.06/MWh, and the re-dispatch premium in excess of the market clearing price (MCP) was approximately $3.7 million or $26.27/MWh. The key point of constraint was the Sylmar Substation.

All incremental OOS dispatches are subject to mitigation. Figure 9 shows the re-dispatch premiums for both decremental and incremental congestion as well as the savings due to mitigation of incremental OOS dispatches. This chart indicates that very little bid mitigation has taken place due to the large thresholds in AMP for local market power. Local market power mitigation of incremental dispatches (AMP LMPM) resulted in moderate reductions of $205,048, or 5.4 percent of total re-dispatch premiums in September.

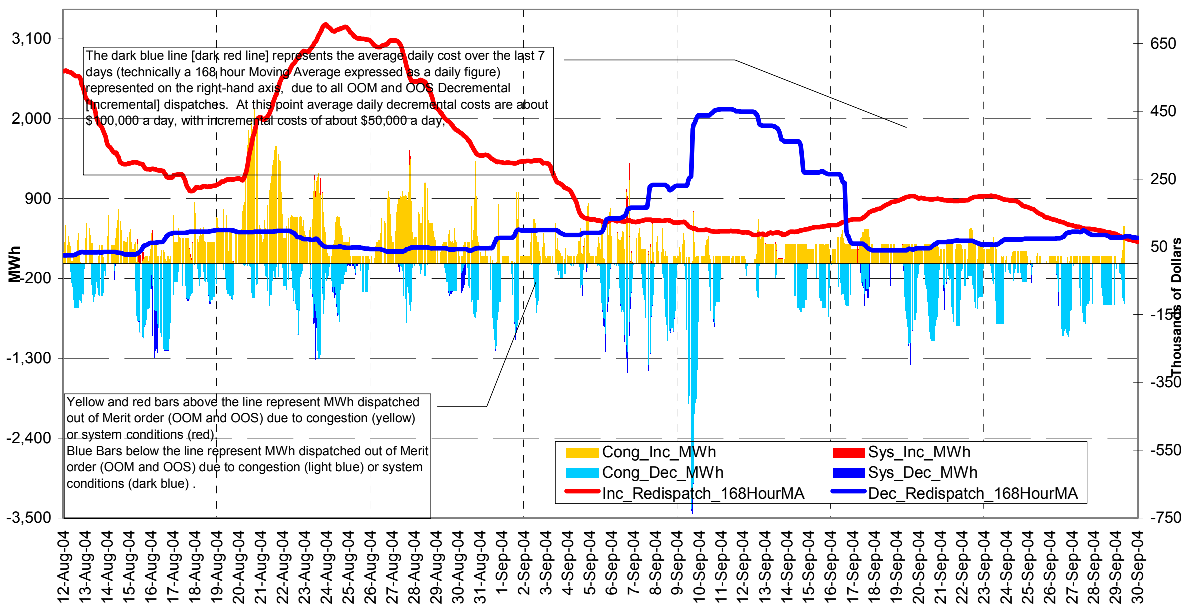
Figure 9. Intra-zonal Re-dispatch Premiums and INC OOS Mitigation Savings



Decremental Intra-zonal Congestion Dispatches. A total of 286 GWh of decremental energy was dispatched out of sequence in September. This energy was settled in accordance with the provisions of the FERC-approved Amendment 50 mitigation measures. The approximate re-dispatch premium in excess of the market clearing price was $8.1 million or $23.86/MWh. By far the bulk of this increase in decremental congestion was due to the resurgence of Miguel transformer bank congestion (72.2 percent), in part due to the high loads and also due to the refueling outages of SONGS Unit 3.

Figure 10 shows the energy dispatched (bar graph on the left axis) and the seven-day daily moving average for the intra-zonal congestion re-dispatch costs. The vast majority of the dispatches were due to congestion (labeled Cong_Inc_MWh and Cong_Dec_MWh), with incidental dispatches due to grid conditions, typically over-generation, voltage support or something similar (labeled Sys_Inc_MWh, and Sys_Dec_MWh). The graph shows September 10 was a particularly bad day for congestion at Miguel. This was a peak load day for both SCE and SDG&E service territories.

Figure 10. Control Area Out-of-Sequence Dispatch Volumes and Costs, Sep 2004



Minimum Load Cost Compensation Costs

Minimum Load Cost Compensation (MLCC) costs incurred for committing units on for intrazonal congestion mitigation remained high at nearly $28 million in September, although somewhat lower than August levels of just over $30 million. This was largely due to decreased Sylmar costs in September. South-of-Lugo (Lugo) remains the single largest cost category. But as summer wanes this cost should decline as South-of-Lugo is mainly a summertime phenomenon. Figure 11 shows minimum-load costs in millions of dollars per month by constraint reason. All costs shown other than system costs are associated with intrazonal congestion mitigation. Table 3 describes the various constraints shown.

Figure 11. Monthly MLCC Costs by Constraint Reason

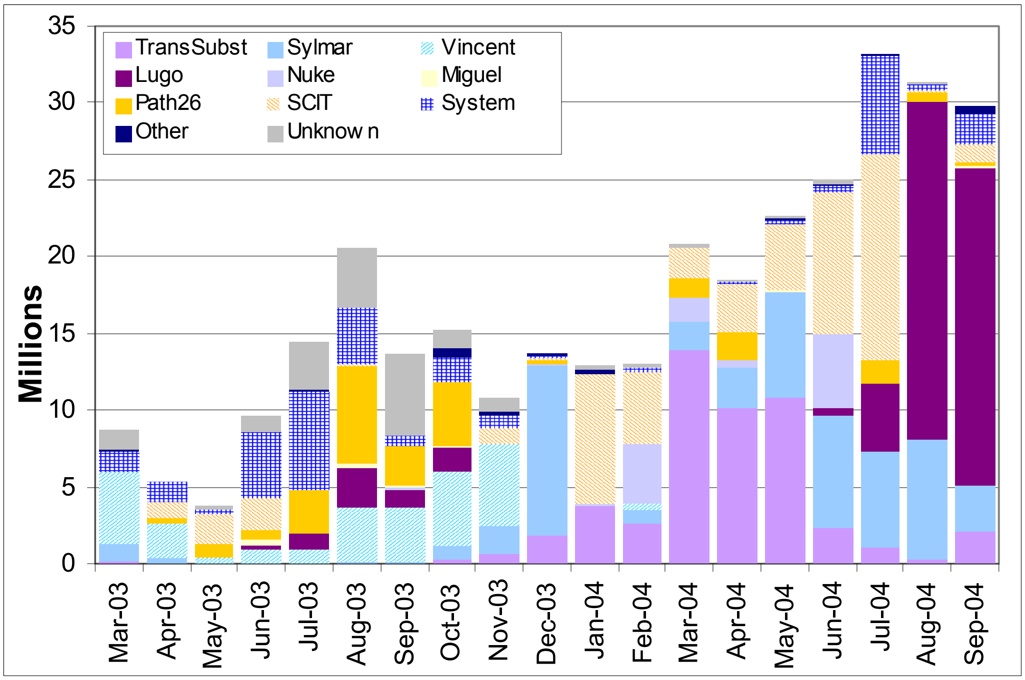


Table 3. Explanations of Minimum-Load Commitment Constraints

Constraint	Description
Miguel	Anticipated congestion at the Miguel Bank feeding into SDG&E service territory
Lugo	South-of-Lugo constraint, between 4800-5100 depending on load
Sylmar	Anticipated congestion at the Sylmar bank, generally due to planned upgrade work
TransSubst	Anticipated congestion due to planned transmission line or substation maintenance
Vincent	Anticipated congestion at the Vincent substation
Nuke	Energy needed due to the absence of one of the four in-state nuclear reactors
Path26	Congestion on Path 26
SCIT	Import limitations due to the Southern California Import Transmission nomogram
System	Energy needed for system needs
Other	Other occasional constraints
Unknown	Reasons not captured

III. Ancillary Services Markets

- *Amendment 60 increases Ancillary Services Market Supply*
- *Average Ancillary Services Costs Down 60 percent from August Levels*

Market Supply. Day-ahead market supply increased due to the implementation of Amendment 60. Pursuant to Amendment 60, the must offer timeline was moved forward prior to the deadline for submitting day-ahead A/S bids on September 2 for market transactions on September 3. Figures 12 and 13 depict the spinning reserve offer volume from MOW-D and Non-MOW-D units in the day-ahead and hour-ahead markets, for the month of September.

Figure 12. Daily Average Day-Ahead Spinning Reserve Bid Volumes

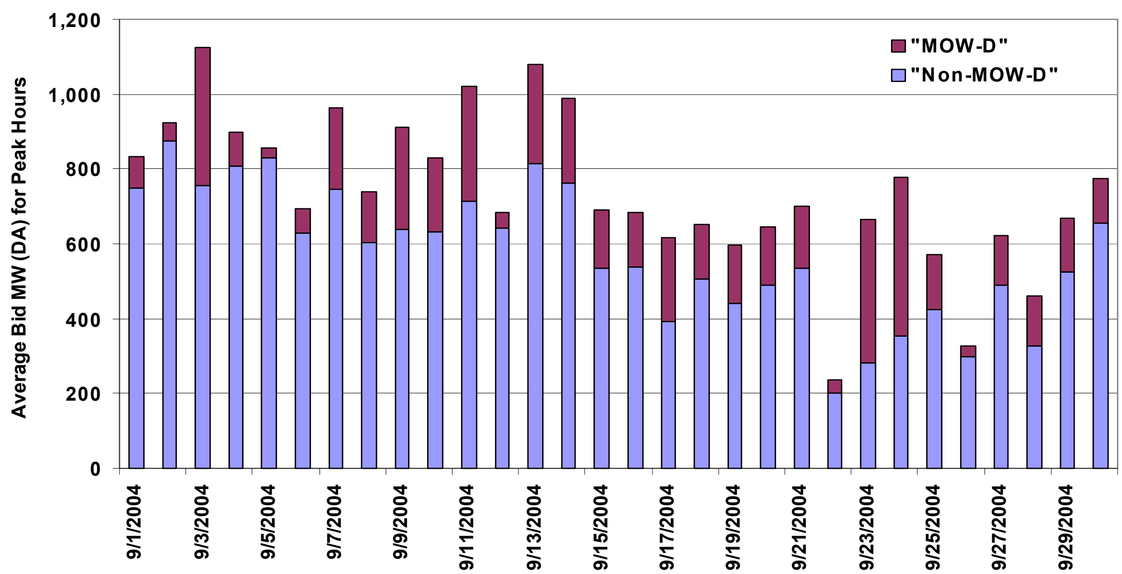
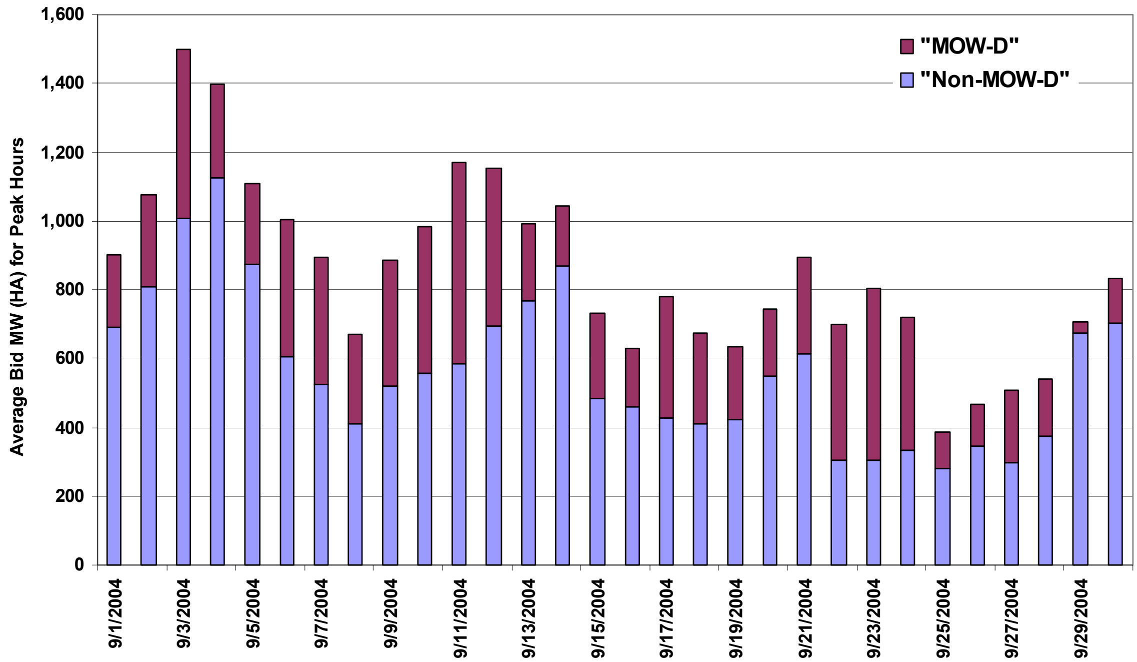


Figure 13. Daily Average Hour-Ahead Spinning Reserve Bid Volumes



Market Prices. September marks the second month of locational procurement in CAISO ancillary services markets. The CAISO implemented zonal procurement of ancillary services on August 7. In spite of a sharp increase in SP15 A/S Requirements to cover record loads, average market prices for the region dropped by 60 percent. Tables 4 and 5 recount the average requirements for each A/S and the weighted average prices for September in the SP15 and NP15 zones.

Table 4. SP15 Average A/S Requirements and Prices

	Average Required (MW)				Weighted Average Price ($/MW)				
SP15	RU	RD	SP	NS	RU	RD	SP	NS	All Services
Aug 04	205	97	294	254	$ 24.63	$ 8.01	$ 17.32	$ 31.49	$22.26
Sep 04	421	473	911	895	$ 10.45	$ 7.16	$ 5.83	$ 16.19	$8.80
Chg	105.4%	389.4%	210.0%	252.7%	-57.6%	-10.7%	-66.3%	-48.6%	-60.5%

Table 5. NP15 Average A/S Requirements and Prices

	Average Required (MW)				Weighted Average Price ($/MW)				
NP15	RU	RD	SP	NS	RU	RD	SP	NS	All Services
Aug 04	347	394	948	852	$ 11.41	$ 7.91	$ 3.65	$ 3.09	$5.18
Sep 04	272	306	675	675	$ 8.81	$ 7.59	$ 4.01	$ 2.07	$4.32
Chg	-21.5%	-22.4%	-28.8%	-20.9%	-22.8%	-4.1%	9.7%	-32.8%	-16.7%

The facts that the September record loads due to a brief heat wave and were prior to the fall unit maintenance season led to favorable overall prices. Figures 14 and 15 display weekly average A/S prices for SP15 and NP15.

Figure 14. SP15 Weekly Weighted Average Ancillary Service Prices

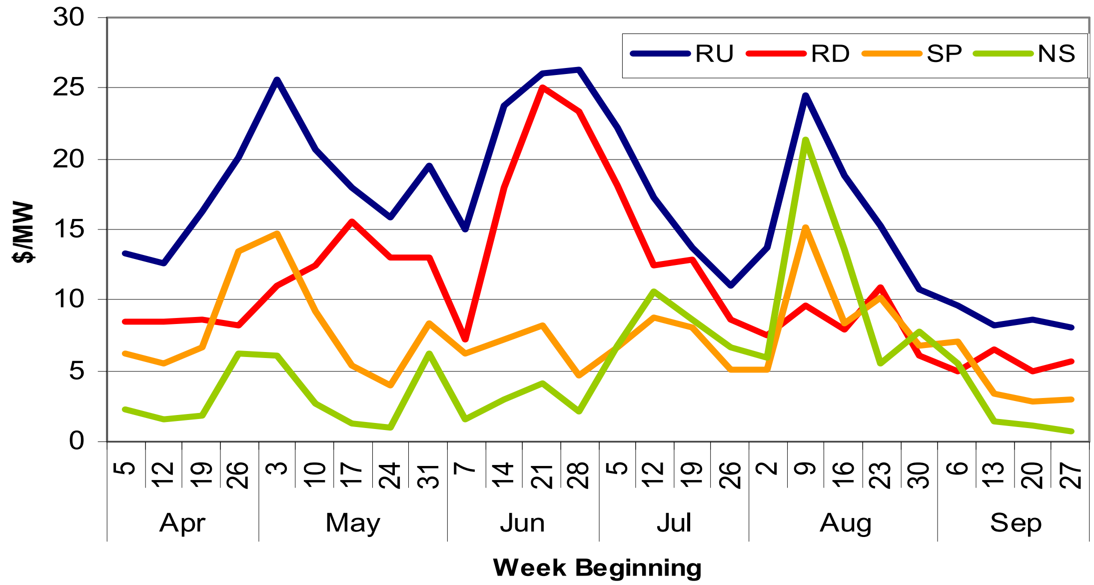
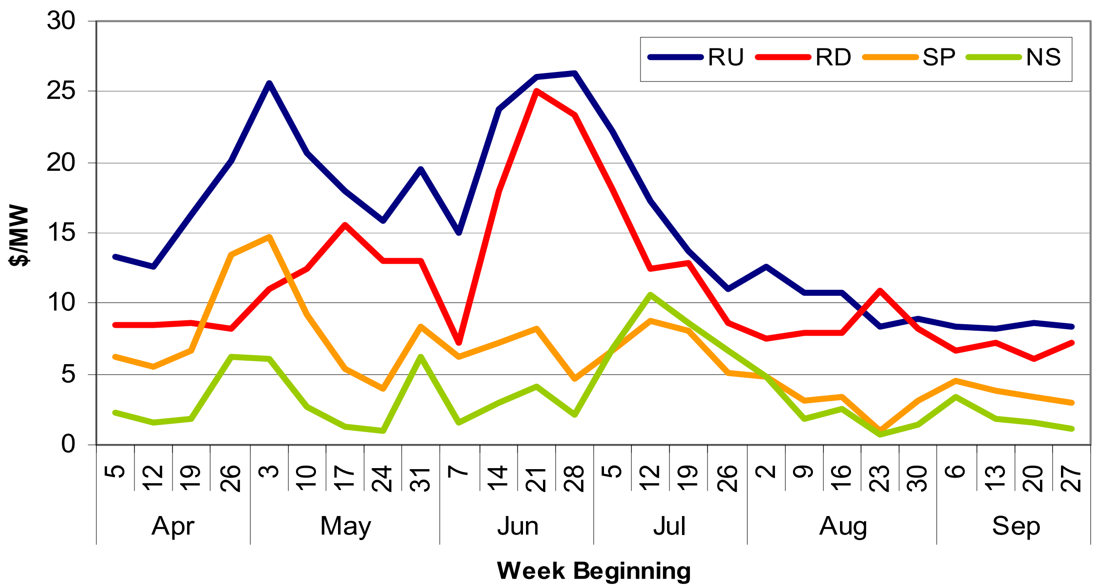


Figure 15. NP15 Weekly Weighted Average Ancillary Service Prices



IV. Inter-zonal Congestion

- *Interzonal congestion due to imports most pronounced on Palo Verde, and on Path 15 in south-north direction*

The robust supply of imports contributed to the highest monthly inter-zonal congestion costs since 2002, totaling approximately $8.8 million in September. Of this, approximately $2.6 million was incurred as import congestion on Palo Verde between September 7 and 11 in nearly all peak hours. Another $1.9 million was incurred as south-to-north congestion on Path 15, dispersed across 20 days of the month, due primarily to the wheeling of low priced power in the Southwest to the Pacific Northwest in off-peak hours. The California-Oregon Intertie (COI) was congested in the import direction on at least 25 days in September, for a total of approximately $1.4 million.

The Palo Verde branch group was congested for 40 percent of hours in the DA import direction at an average price of $8, and 12 percent of hours in the HA import direction, at an average congestion price of $28. Palo Verde suffered a great deal of congestion on September 8, a peak load day for SCE and SDG&E, as well as on September 18 and 19, when the branch group was derated due to work on the SWPL line.

Path15 was congested mainly in the import direction for 20 percent of all hours in the DA at an average congestion price of $4, and 12 percent of all hours in the HA, at an average price of $22. Path 15 experienced congestion throughout the month, but particularly earlier in the month when loads were higher.

COI was congested 38 percent of the time in the DA import direction at an average price of $4, and 33 percent of the time in the HA import direction at an average price of $17. COI was significantly derated for four days early in the month when the Table Mountain-Tesla 500kV line was cleared for line work as well as later in the month for seven days when the Grizzly-Malin 500kV line was subject to maintenance.

Figure 16 shows inter-zonal congestion costs by path and direction in September. Tables 6 and 7 show congestion costs, frequencies, and prices by branch group.

Figure 16. September Monthly Interzonal Congestion Costs by Path and Direction[7]

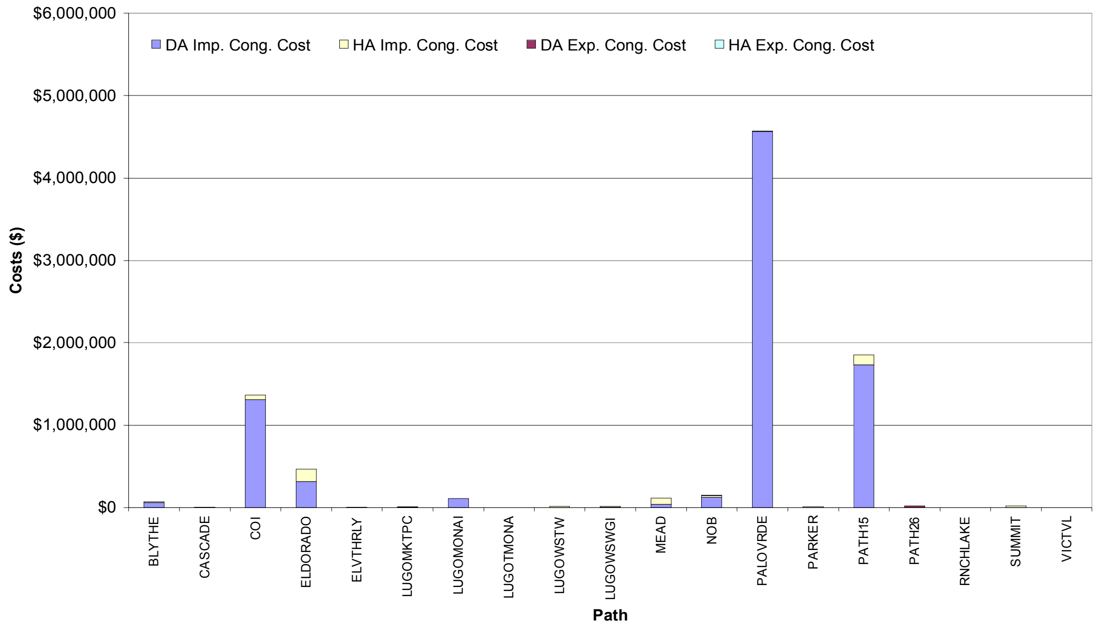


Table 6. Congestion Costs by Branch Group in September

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost
	Import	Export	Import	Export	Import	Export	Day-ahead	Hour-ahead	
BLYTHE _BG	$57,456	$0	$12,583	$0	$70,039	$0	$57,456	$12,583	$70,039
CASCADE _BG	$194	$0	$22	$960	$217	$960	$194	$983	$1,177
COI _BG	$1,312,409	$0	$50,526	$0	$1,362,935	$0	$1,312,409	$50,526	$1,362,935
ELDORADO _BG	$317,773	$0	$148,014	$0	$465,787	$0	$317,773	$148,014	$465,787
ELVTHRLY _BG	$0	$14	$0	$1,264	$0	$1,279	$14	$1,264	$1,279
LUGOMKTPC_BG	$1,186	$0	$6,718	$0	$7,904	$0	$1,186	$6,718	$7,904
LUGOMONAI_BG	$108,062	$0	$0	$0	$108,062	$0	$108,062	$0	$108,062
LUGOTMONA_BG	$640	$0	$0	$0	$640	$0	$640	$0	$640
LUGOWSTWG_BG	$0	$0	$12,624	$0	$12,624	$0	$0	$12,624	$12,624
LUGOWSWGI_BG	$4,089	$0	$12,430	$0	$16,519	$0	$4,089	$12,430	$16,519
MEAD _BG	$41,924	$0	$75,881	$0	$117,805	$0	$41,924	$75,881	$117,805
MERCHANT _BG	$2	$0	$0	$0	$2	$0	$2	$0	$2
NOB _BG	$124,383	$0	$17,864	$8,189	$142,247	$8,189	$124,383	$26,053	$150,436
PALOVRDE _BG	$4,562,750	$0	$8,607	$0	$4,571,357	$0	$4,562,750	$8,607	$4,571,357
PARKER _BG	$0	$0	$5,789	$0	$5,789	$0	$0	$5,789	$5,789
PATH15 _BG	$1,730,483	$0	$123,432	$0	$1,853,915	$0	$1,730,483	$123,432	$1,853,915
PATH26 _BG	$0	$18,170	$0	$908	$0	$19,079	$18,170	$908	$19,079
RNCHLAKE _BG	$0	$1,023	$0	$0	$0	$1,023	$1,023	$0	$1,023
SUMMIT _BG	$828	$0	$16,766	$0	$17,594	$0	$828	$16,766	$17,594
VICTVL _BG	$0	$14	$0	$0	$0	$14	$14	$0	$14
Total	$8,262,179	$19,222	$491,254	$11,322	$8,753,433	$30,544	$8,281,401	$502,576	$8,783,977

[7] On Path 15 and Path 26, "Import" refers to the south-to-north direction; "Export" refers to the north-to-south direction.

Table 7. Average Congestion Prices and Frequencies of Congestion in September

	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	$153		1	0	$54	
CASCADE _BG	23	0	$0		11	0	$9	
COI _BG	38	0	$4		33	0	$17	
ELDORADO _BG	12	0	$4		18	0	$14	
ELVTHRLY _BG	0	0			0	0		$62
LUGOMKTPC_BG	0	0	$2		1	0	$30	
LUGOMONAI_BG	7	0	$9		0	0		
LUGOTMONA_BG	1	0	$1		0	0		
LUGOWSTWG_BG	0	0			4	0	$10	
LUGOWSWGI_BG	8	0	$2		14	0	$6	
MEAD _BG	8	0	$1		6	0	$25	
NOB _BG	16	0	$1		14	0	$12	
PALOVRDE _BG	40	0	$8		12	0	$28	
PARKER _BG	0	0			1	0	$12	
PATH15 _BG	20	0	$4		12	0	$22	
PATH26 _BG	0	1		$1	0	1		$5
RNCHLAKE _BG	0	0		$1	0	0		
SUMMIT _BG	10	0	$0		5	0	$13	
VICTVL _BG	0	0		$0	0	0		

V. 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 and municipal utilities. Table 8 shows the extent to which FTRs were scheduled on the various paths connecting to the CAISO control area.

Table 8. FTR Scheduling Statistics - 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 _BG	168	87	167	167	52%
IMP	ELDORADO _BG	536	500	536	536	93%
IMP	IID-SCE _BG	600	456	467	447	76%
IMP	LUGOIPPDC_BG	370	181	370	235	49%
IMP	LUGOMKTPC_BG	247	34	65	50	14%
IMP	LUGOTMONA_BG	160	54	117	65	34%
IMP	LUGOWSTWG_BG	93	18	44	27	20%
IMP	MEAD _BG	624	9	54	25	2%
IMP	NOB _BG	725	58	148	100	8%
IMP	PALOVRDE _BG	1021	636	770	600	62%
IMP	SILVERPK _BG	10	10	10	10	99%
IMP	VICTVL _BG	921	4	25	25	0%
EXP	CFE _BG	100	10	32	32	10%
EXP	LUGOMKTPC_BG	247	3	3	3	1%
EXP	NOB _BG	722	13	83	83	2%
EXP	PATH26 _BG	1141	396	853	483	35%

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

FTR Revenue per Megawatt. FTR revenues in September increased for almost all branch groups, with the most congested branch groups (Palo Verde and COI) seeing the most significant absolute increases in revenues. Table 9 shows the FTR revenue per MW for each branch group in 2004.

Table 9. FTR Revenue Per MW ($/MW) - 2004

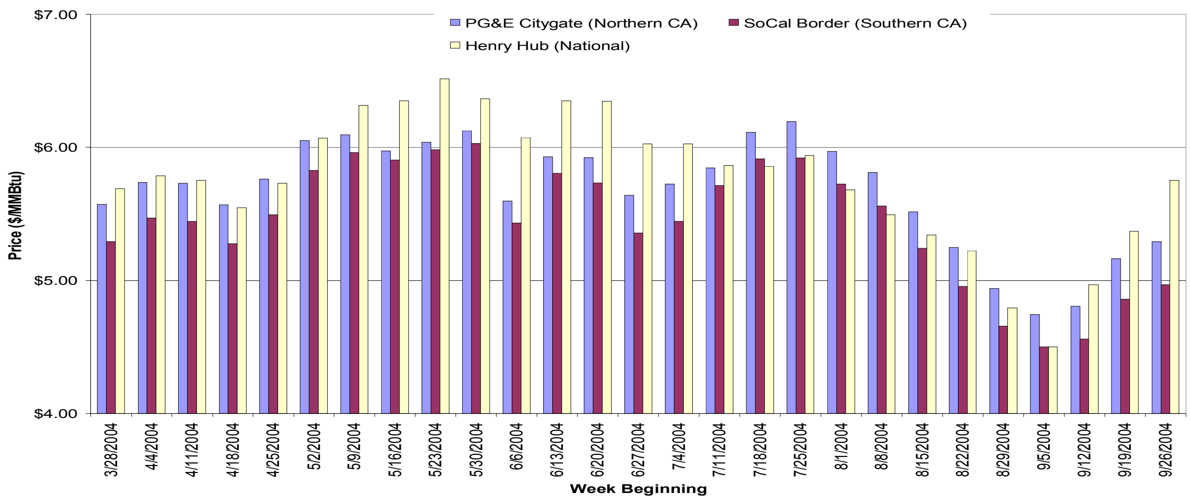
Direction	Branch Group	Net $/MW FTR Rev Apr	May	Jun	Jul	Aug	Sep	Cumm Net $/MW FTRREV	Pro Rated NET $/MW FTRREV	FTR Auction Price
IMPORT	BLYTHE	2,791	5,540	433	0	7	736	9,506	19,012	8,759
IMPORT	COI	199	1,481	4,853	822	521	2,554	10,430	20,860	26,964
IMPORT	ELDORADO	0	408	10	0	0	400	818	1,635	45,169
IMPORT	LUGOIPPDC	3	0	0	0	0	0	3	6	63,374
IMPORT	LUGOMKTPC	0	0	0	0	5	160	165	330	81,579
IMPORT	LUGOTMONA	0	0	192	0	0	8	200	400	99,784
IMPORT	LUGOWSTWG	0	1	0	0	17	679	697	1,393	117,989
IMPORT	MEAD	1,223	1,168	634	464	238	930	4,657	4,657	136,194
IMPORT	NOB	336	1,816	19,123	3,725	1,013	1,272	27,285	27,285	154,399
IMPORT	PALOVRDE	2,074	15,146	2,457	9,505	8,173	16,719	54,074	54,074	172,604
IMPORT	PARKER	115	15	0	5	6	178	319	638	190,809
S-N	PATH15	0	20	20	5	287	597	928	1,856	209,014
IMPORT	SILVERPK	0	0	0	0	5	0	5	9	227,219
EXPORT	NOB	0	0	0	910	522	0	1,433	1,433	245,424
N-S	PATH26	427	27	357	573	139	22	1,545	3,090	263,629
EXPORT	SILVERPK	0	0	0	0	480	0	480	960	281,834
EXPORT	SUMMIT	0	0	608	0	39	0	647	1,294	300,039

* FTRs on these paths were awarded to municipal utilities that converted their lines to CAISO control and, therefore, were not released in the primary auction.

VI. Regional Natural Gas Markets

The successive impact of multiple hurricanes in the Gulf region contributed to the continual increase in natural gas prices through September, particularly at Henry Hub, where the impact was most acute. Higher than normal temperatures throughout California further increased natural gas prices as more gas-fired generation was dispatched to meet air conditioning load. Hurricane Ivan's impact was most severe on September 13, when Henry Hub prices jumped from $4.58 to $5.14/MMBtu. Initially, these prices lasted only for a few days, after which Henry Hub prices receded to $4.82/MMBtu. However, greater than expected damage from Hurricane Ivan, along with increasing temperatures in the west generated a steady climb in prices beginning on September 20. Technical trading to cover short positions resulted in the sudden price increase on September 29. Average daily gas prices for September were $5.03/MMBtu at Henry Hub, $4.56/MMBtu at Malin, $4.96/MMBtu at PG&E Citygate, and $4.68/MMBtu at Southern California Border Average. In October, these prices steadily increased, reaching $6.76/MMBtu (PG&E Citygate) by October 23. Figure 17 shows weekly average gas prices through September.

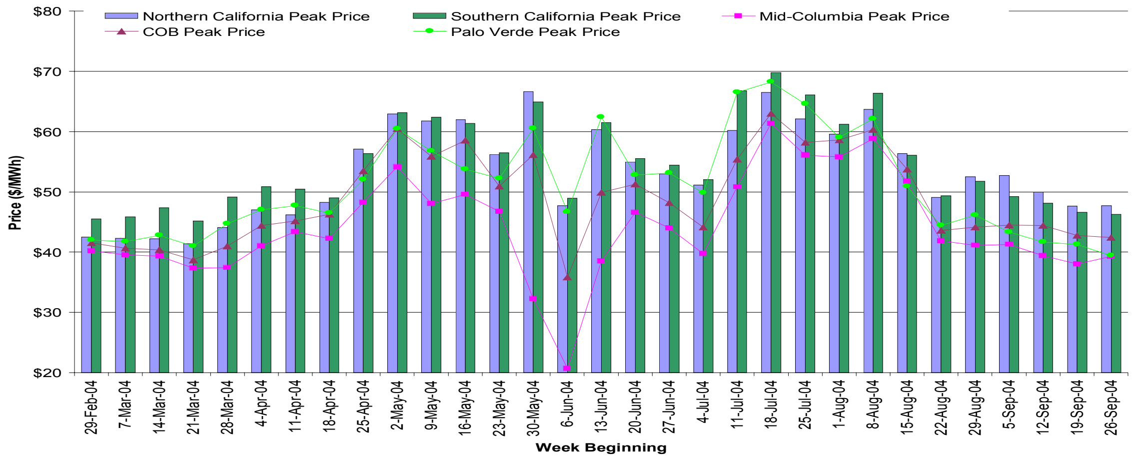
Figure 17. Weekly Average Natural Gas Prices through September



VII. Regional Bilateral Electric Power Markets

In contrast to natural gas prices, regional day-ahead electricity prices declined slightly through September. Hotter weather and heavier loads drove prices from $50 to $58/MWh on September 8. As temperatures declined around September 17, California prices returned to between $45 and $47/MWh, and remained in the upper $40s to lower $50s for the rest of September. Average September peak weekday regional day-ahead electricity prices were $45.20/MWh at the California-Oregon Border, $40.83/MWh at Mid-Columbia, $44.27/MWh at Palo Verde, $51.45/MWh in Northern California, and $50.91/MWh in Southern California. Figure 18 shows weekly average prices through September.

Figure 18. Weekly Average Day-Ahead Western Bilateral Electric Hub Prices through September



VIII. Issues under Review

MRTU Phase 1b. MRTU Phase 1b was implemented on October 1. Phase 1b is a complete redesign and replacement of the previously existing methodology and software for dispatching resources in real time. Its key features include:

- *Single market-clearing price.* As of October 1, the CAISO is now reporting a single market-clearing dispatch price for energy in each interval, rather than separate prices for incremental and decremental energy.
- *Five-minute dispatch intervals.* In order to be more responsive to load fluctuations, the CAISO now dispatches resources every 5 minutes, or twelve times per hour. Previously, the CAISO had dispatched units every ten minutes. However, settlements will continue to be on a ten-minute basis, using prices that are averages of the two five-minute dispatch prices.
- *Automated software.* The Real-Time Market Application (RTMA) element automates many of the dispatch functions that the CAISO previously did manually. For example, RTMA identifies transmission and generation constraints within the dispatch algorithm, dispatches resources accordingly, and splits the dispatch between NP15 and SP15 whenever it predicts a transmission constraint on either Path 15 or Path 26.
- *Least-cost economic dispatch.* Whenever the CAISO receives real-time DEC bids above the market-clearing price (MCP), which effectively are from units willing to pay at least the MCP to avoid generating, it will now accept those bids and replace the energy by purchasing additional INC energy at the MCP from other resources. Previously, the CAISO automatically lowered those high-priced DEC bids and raised low-priced INC bids to a common "Target Price" to create a single bid stack from which it would procure against the imbalance.

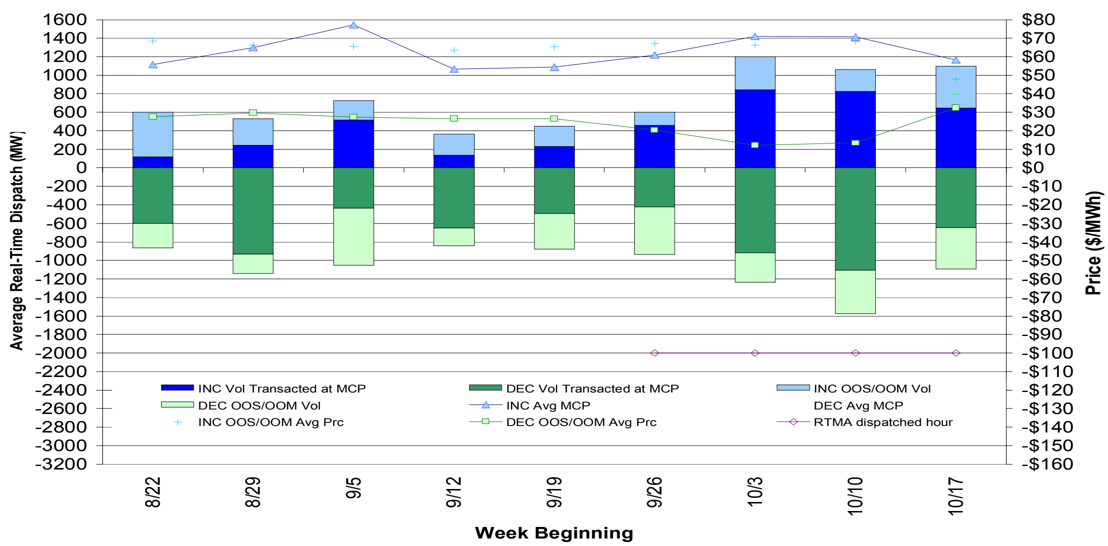
- *Look-Ahead.* *A* two-hour forecast is used to identify congestion and commit units so that they are ready to respond to instructions when needed.

Since going live, Phase 1b has had several noticeable impacts on the market. While it is premature to assess the total impact of Phase 1b, the Departments of Market Analysis and Market Operations have and will continue to work together to determine its effects. Isolating the effect of Phase 1b has been challenging because several structural events occurred concurrently with Phase 1b implementation. In particular, both the SONGS Unit 3 and PDCI outages began on or around October 1, making it difficult to isolate the effects of Phase 1b itself. For example, in addition to reducing supply to southern California, these outages also lowered the SCIT constraint (the quantity of energy that can be simultaneously imported into southern California). Regardless of Phase 1b, this constraint change would have the effect of decreasing competitiveness within southern California by limiting bids serving SP15 to those from resources within the zone, and from potentially fewer imports from the southwest and northern California. Meanwhile, prices for natural gas, which have a direct effect on electric power production, increased considerably in October, from the range of $4 to $4.50/MMBtu in early October to nearly $7/MMBtu by October 21.

The following discussion identifies some of the trends that we have observed to date.

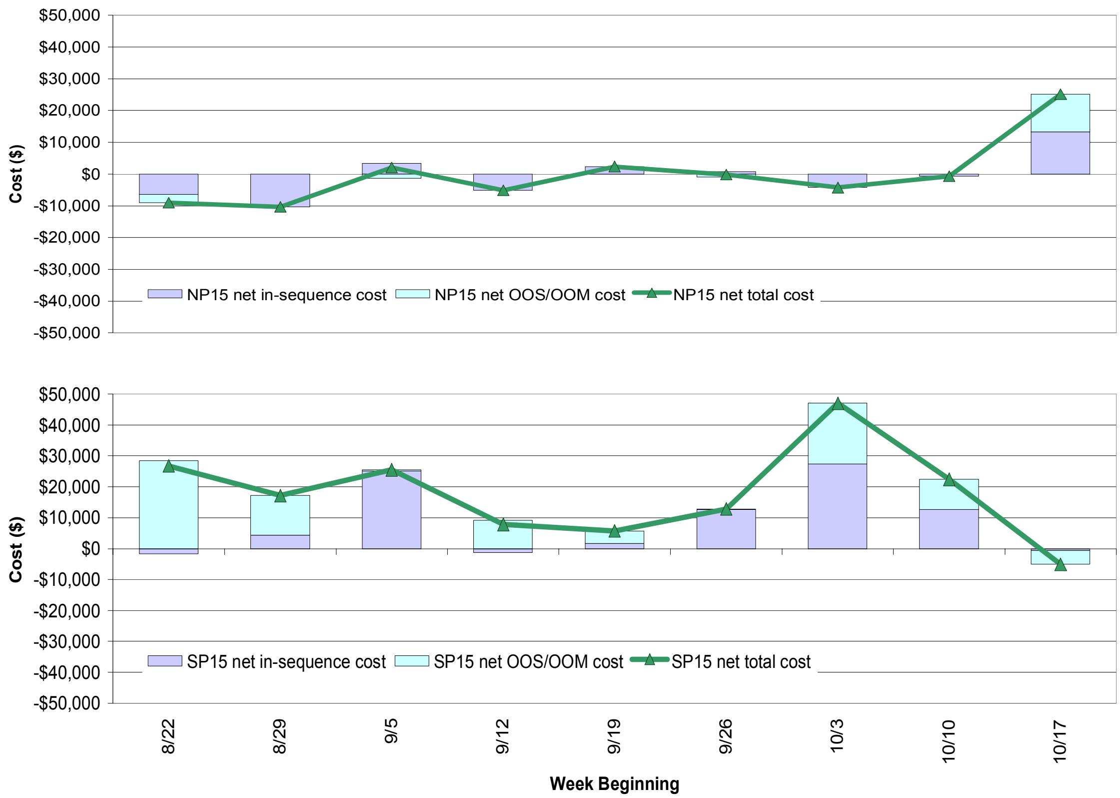
Real-time prices. Overall prices paid for energy have averaged $42.89/MWh within NP15 and $47.19 within SP15. Volumes have largely been incremental within NP15, but balanced between incremental and decremental within SP15. In general, dispatch volumes of both incremental and decremental energy have increased, with greater proportions of both incremental and decremental energy procured in sequence than in recent months. Figure 19 shows weekly average CAISO BEEP/RTMA in-sequence and OOS/OOM volumes and prices between August 24 and October 23.

Figure 19. Weekly Average CAISO Real-Time In-Sequence And OOS/OOM Prices through October 23



Real-time Energy Costs. Real-time energy costs and price volatility increased during the first week of implementation as CAISO operators and engineers resolved technical issues with the software and operation. Since then, they have declined considerably, particularly within SP15, as incremental costs have been offset by decremental credits. Between October 19 and 21, significant incremental costs were incurred within NP15. Figure 20 shows weekly average CAISO in-sequence and OOS/OOM energy costs between August 24 and October 23.

Figure 20. Weekly Average NP15 (Top) and SP15 (Bottom) CAISO Real-Time In-Sequence And OOS/OOM Costs through October 23



Price Spikes. Price spikes have occurred frequently since Phase 1b implementation, particularly in the week immediately following deployment. Prices most often exceed $100/MWh in the first one or two intervals each hour, during which units are ramping between schedules. As the imbalance shifts rapidly during these intervals, RTMA often dispatches deep into the bid stack, as several units moving at full ramp capability are needed to maintain balance. However, once the system is in balance, usually within five or ten minutes, RTMA can ramp up the less-expensive resources as it backs down the more costly resources, effectively trading them, for a least-cost dispatch. The result of this clearing is sometimes high, but short-lived, price spikes. Price spikes also occur primarily during the morning and afternoon upward load ramping periods and the evening downward load ramping periods. The following charts show the frequency of prices above $100/MWh. The first shows the number of price spike intervals by hour of day, compared to actual load, between October 17 and 23, for both NP15 and SP15. The second shows spike intervals by dispatch interval.

Figure 21. Price Spike Frequencies by Hour of Day: October 17-23

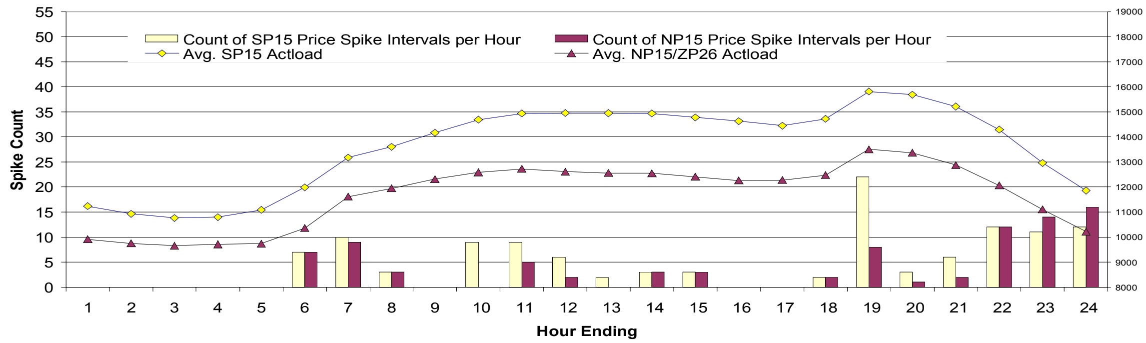
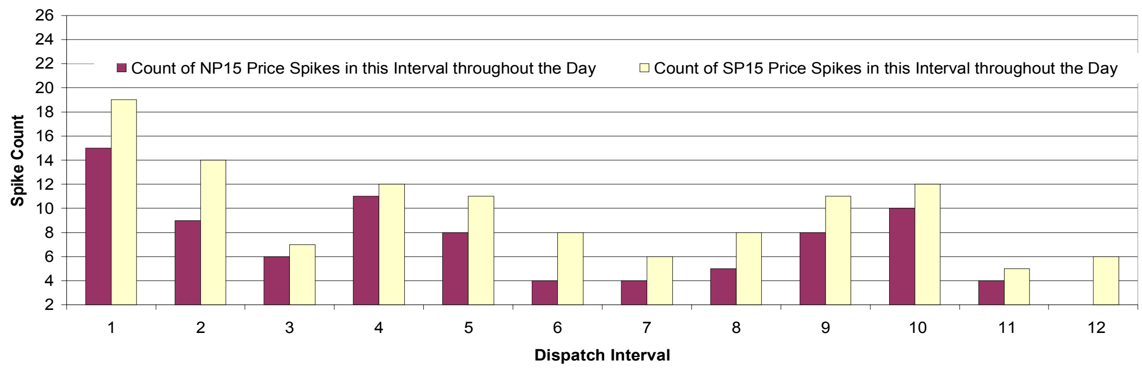


Figure 22. Price Spike Frequencies by Interval: October 17-23



Palo Verde-Devers 2 Transmission Expansion Economic Impact Study. DMA is heavily involved in the economic analysis of the Palo Verde Devers Line #2, but has not yet reached a final recommendation. An update will be provided to the Board of Governors on November 10. Please see Board Memo for more information.

Market Surveillance Committee (MSC). The MSC is currently preparing opinions on the MRTU Existing Transmission Contracts, Virtual Bidding/Trading Hubs, TAPAS, and Market Power Mitigation proposals. They will be submitted on or about November 16, 2004.

Ancillary Service Market Performance under Amendment 60 and Locational Procurement. DMA assessment of the impacts of the recent changes on the ancillary service markets show initial indications that the majority of available capacity is, in fact, offered into the SP15 A/S markets. Thus scarcity and supply issues arise. DMA continues to assess A/S market concentrations in SP15, market participant bidding behavior during times of locational procurement as well as bidding behavior since Phase 1B implementation. The DMA will provide the results of the analysis to FERC for further review.