Annual Report

Market Issues and Performance

2006

Department of Market Monitoring

California Independent System Operator

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Overview

Each year the Department of Market Monitoring (DMM) publishes an annual report on the performance of markets administered by the California Independent System Operator (CAISO). This report covers the period of January 1, 2006 through December 31, 2006.

From an operational standpoint, 2006 was a year of extremes with operational challenges in the spring due to excessive hydroelectric generation and in the summer due to a record breaking heat wave. Through it all, grid reliability and the markets fared very well. A well above average snowpack throughout California and the Pacific Northwest resulted in an abundance of hydroelectric generation production in the first half of the year. High volumes of hydroelectric production caused persistent over-generation conditions and unscheduled loop flow issues that created real-time operational challenges and caused a high degree of price volatility in the Real Time Market. The abundance of hydroelectric power coupled with lower natural gas prices also had a significant impact of reducing day-ahead spot energy prices. In the first half of the year, day-ahead energy prices in Southern California averaged approximately $51/MWh, compared to $84/MWh for the same period last year.

However, in a matter of weeks, California and the rest of the West went from surplus generation to supply scarcity conditions as the entire region experienced an unprecedented heat wave lasting nearly three weeks in July. System operation and the market were pushed to their limits during this period and performed very well. From a reliability standpoint, the record setting July heat wave only resulted in one Stage 2 Emergency[1] and no Stage 3 Emergencies (involuntary load interruptions). On the market side, spot energy and ancillary service prices rose significantly during the heat wave with day-ahead prices frequently at the $400 soft bid cap. However, prices in the CAISO Real Time Market were much lower due to an extremely high level of forward scheduling, which resulted in minimal imbalance energy demand and in many cases caused the CAISO to dispatch generation down.

Overall, despite the extreme range of system conditions, California's spot wholesale energy markets in 2006 were generally stable and competitive, similar to the past several years (2002-2005). However, as discussed in prior reports, the slow pace of new generation investment in California remains a concern. One of the primary metrics that the CAISO uses to gauge overall market competitiveness is a 12-month Market Competitive Index (MCI), which represents a 12-month rolling average of the estimated hourly price-cost mark-ups (i.e., the difference between actual energy prices and estimated "competitive" prices derived from cost-based simulations). The CAISO considers MCI values in the range of $5-$10/MWh to be reflective of a workably competitive market. The monthly MCI values estimated for 2006 were either below or within this range for all months of the year.

The average estimated cost of wholesale energy in 2006 was $47.55/MWh of load compared to $57.83/MWh in 2005. Costs include the following components: forward scheduled energy, inter-zonal congestion, real-time imbalance energy, real-time out-of-sequence (OOS) energy

[1] Stage 2 Emergency Notice is declared by the CAISO any time it is clear that an Operating Reserve shortfall (less than 5 percent) is unavoidable.

redispatch premium, net Reliability Must Run (RMR) costs, ancillary services, and CAISO-related costs (transmission, reliability, and grid management charges). The decrease in the costs in 2006 was primarily due to lower natural gas prices in 2006, particularly in the September-December period when there was a sharp increase in natural gas prices in 2005 due to the supply interruptions from the Gulf Coast hurricanes. An abundance of hydroelectric generation in 2006 also contributed to the decline.

One of the major success stories reported in the 2005 Annual Report on Market Issues and Performance was the sharp reduction in intra-zonal congestion costs. Intra-zonal congestion cost is comprised of three components: 1) Minimum Load Cost Compensation (MLCC) for units denied must-offer waivers, 2) real-time RMR costs, and 3) real-time redispatch costs. In 2005, intra-zonal congestion costs totaled $222 million, compared to $426 million in 2004, representing a 48 percent decrease. For 2006, total intra-zonal congestion costs declined further to $207 million. The relatively low levels of intra-zonal congestion costs over the past two years is the result of various transmission enhancements in 2005 and 2006 that were targeted to address frequently congested areas. Transmission enhancements also helped to reduce total RMR costs, which include annual fixed option payments and total dispatched energy costs. Total RMR costs declined substantially from approximately $505 million in 2005 to $428 million in 2006, a reduction of approximately $77 million. This reduction resulted from a decline in RMR dispatched energy costs from approximately $254 million in 2005 to $168 million in 2006, a 34 percent decrease. The fixed option RMR payments increased slightly in 2006 (3.7 percent), which partially offset the decline in RMR dispatch costs.

Though the CAISO markets and short-term bilateral energy markets were stable and competitive in 2006, the moderate pace of new generation investment in Southern California coupled with the continued reliance on aged generation units and significant load growth remains a reliability concern for the peak summer season. Though a significant amount of new generation capacity was added to SP15 in 2005 (2,376 MW), less was added in 2006 (434 MW), and SP15 experienced approximately 1,770 MW of generation retirements during the past two years. As a consequence, new generation investment within Southern California is not keeping pace with the significant load growth in that region and unit retirements. This has resulted in a higher reliance on imported power from the Southwest, Northwest, and Northern California. This dependence on imports, coupled with tight reserve margins, makes Southern California very vulnerable to reliability problems should there be a major transmission outage. Moreover, much of the existing generation within Southern California is comprised of older facilities that are more prone to forced outages, especially under periods of prolonged operation as occurred during the extraordinarily long heat wave in July, with loads exceeding 40,000 MW for all but one day during the 24 day period of July 5 to July 28. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in Southern California. The implementation of the CPUC Resource Adequacy Program in 2006 coupled with implementation of Local Resource Adequacy Requirements and continued regulatory focus on utility long-term procurement are all positive developments for facilitating new generation investment in key areas of the grid. Additionally, another 1,300 MW of new generation is projected to be on-line in SP15 by the end of 2008 with no unit retirements anticipated.

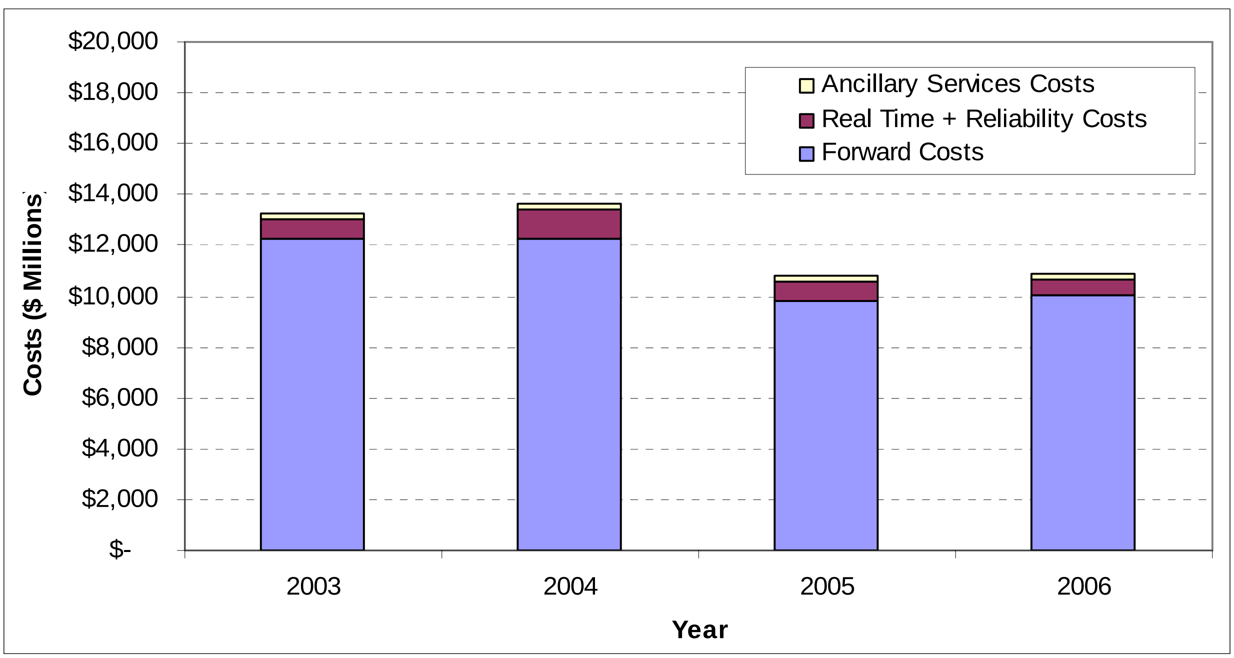
The DMM’s financial assessment of the potential revenues a new generation facility could have earned in California’s spot market in 2006 indicates estimated spot market revenues fell short of the unit’s annual fixed costs. This marks the fifth straight year that the DMM’s analysis found that estimated spot market revenues failed to provide sufficient fixed cost recovery for new generation investment. However, the analysis for the past three years (2004-2006) does show a positive trend of net revenues increasing for a new combined cycle unit with estimated net-market revenues in 2006 nearing the $90/kW-year break-even point for fixed recovery. In 2006, the net revenues for a new combined cycle unit were estimated at approximately $85/kW-year, compared to $69/kW-year and $51/kW-year in 2005 and 2004, respectively. The increase in 2006 can be primarily attributed to the combination of a higher bid cap in 2006 (from $250/MWh to $400/MWh) and the prolonged July heat wave, which resulted in day-ahead bilateral prices well above $250/MWh in numerous hours.

Despite the positive trend in spot market revenues, the fact that California's spot markets fail to provide sufficient market revenues for fixed cost recovery five years in a row underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. While long-term contracting is critical for facilitating new investment, it must be coupled with appropriate deliverability and locational requirements to ensure new investment is occurring where it is needed. The CPUC implementation of Local Resource Adequacy Requirements in January 2007, which are based on CAISO technical studies, should help in facilitating generation development in critical areas of the grid.

Total Wholesale Energy and Ancillary Service Costs

Total estimated wholesale energy and ancillary service costs declined by 16 percent in 2006 from $13.6 billion in 2005 to $11.4 billion in 2006.[2] The forward energy cost component declined in 2006 by 16 percent, mainly due to lower natural gas prices. In addition, the real-time and reliability costs component declined in 2006 by 24 percent from 2005.

Figure E.1 2003 – 2006 Wholesale Energy Cost Components



[2] Unlike previous annual reports, the annual cost estimates shown here include the cost of RMR dispatch. This cost is included in the category shown in Figure E.1 as "Real Time + Reliability Costs."

Market Rule Changes

Increase in Bid Cap for Energy and Ancillary Services

On January 14, 2006, the energy bid cap in the CAISO Real Time Energy Market was raised from $250/MWh to $400/MWh, and on February 14, 2006, the bid cap for ancillary services was also raised from $250/MWh to $400/MWh. The DMM and the Market Surveillance Committee (MSC) spearheaded this increase in response to rising natural gas prices in late 2005, which were brought on by the gulf coast hurricanes. The DMM and the MSC expressed concern that if natural gas prices continued to escalate during the peak winter heating season, the marginal costs of some generation units could increase above the then current bid cap of $250/MWh. Though the energy bid cap is a "soft-cap" meaning that suppliers could bid above the cap and be paid their bid price provided they could cost justify the bid, both the DMM and MSC were concerned that suppliers, particularly importers, might elect not to offer into the CAISO Real Time Market rather than run the regulatory risk and burden of having their bids cost justified. DMM also pointed out a number of other advantages to having a higher bid cap such as providing increased incentives for forward contracting and greater incentives for generator availability during peak demand periods.

Though natural gas prices declined shortly after raising the bid cap, due to an unusually mild winter in the Eastern U.S. that reduced demand for gas, the $400 bid cap for energy and ancillary services has remained in place. It is not possible to precisely assess the impact the higher bid cap has had on the Western market as it would require knowing the counterfactual scenario of what market prices would have been had the bid cap remained at $250/MWh. However, overall it appears that the higher cap has had little impact on the market during most of 2006 and may have been very beneficial to the market and grid reliability during the July 2006 heat wave in the following respects:

- During the record heat wave in July 2006, generation forced outages remained at extraordinarily low levels given the extreme conditions. As the DMM pointed out in recommending the $400 bid cap, a higher bid cap coupled with a high level of forward contracting increases the incentive of suppliers to maintain generating units at a higher level of availability in order to cover their energy contract positions as well as to sell any excess capacity (beyond contract coverage) to the spot market.

- Spot market prices for energy and reserves increased to levels above $250/MWh in numerous hours during the July heat wave. The additional market revenues earned during this period increased the financial viability of new generation investment. Though the DMM's net revenue analysis for 2006 still indicates that estimated net spot market revenues for new generation are below a unit's going forward cost, the gap was much smaller in 2006.

- Though California's major Load Serving Entities (LSEs) most likely incurred some additional costs during the heat wave, the fact that the vast majority of their energy demands were met with their own generation and forward contracts significantly mitigated the financial impact – underscoring the critical importance of hedging spot market exposure.

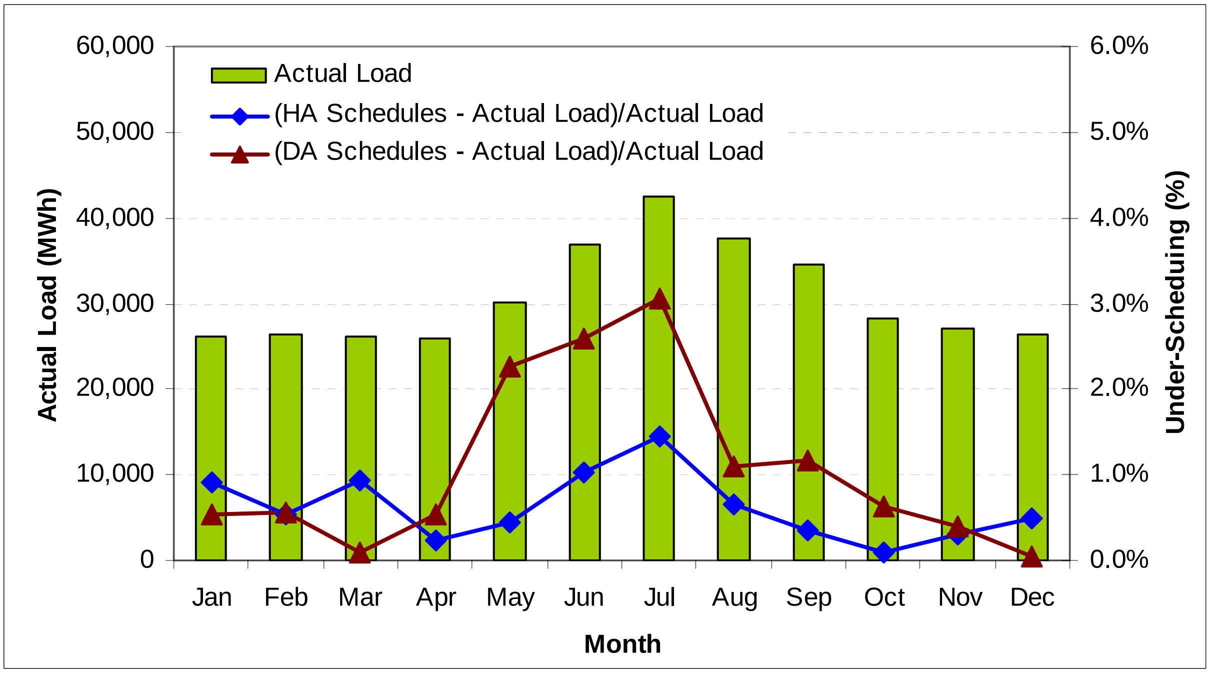
One persistent but relatively minor impact of the higher bid cap is that periodic price spikes in the CAISO Real Time Market that were previously at or near $250/MWh are now typically at or near $400/MWh. Such price spikes were more frequent during the first half of 2006 (occurring in approximately 1.2 percent of the 5-minute intervals), primarily because the over-generation conditions stemming from an abundance of hydroelectric energy reduced the supply of 5-minute dispatchable energy bids being offered to the Real Time Market, resulting in more frequent price spikes. However, the dispatch volumes in the Real Time Market were very minimal (2.6 percent of total load) and, therefore, the cost impact of these spikes were also minimal. Price spikes in the Real Time Market continued to occur in the second half of 2006 but were less frequent due to more thermal generation being on-line and offering into the market as well as a transition out of over-generation conditions.

Enforcement of Amendment 72 – Load Scheduling Requirement

In October 2005, the CAISO filed Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95 percent of their forecast demand for each hour of the next day. The 95 percent day-ahead scheduling requirement was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against under-scheduling, such as requiring additional capacity to be on-line through must-offer waiver (MOW) denials and dispatching additional energy in the real time. Beginning in the spring of 2006, the DMM phased in enforcement of the LSEs' reporting requirements under Amendment 72.

Figure E.2 shows, by month, average actual load together with day-ahead and hour-ahead under-scheduling for peak hours in 2006. Even in July when average load peaked, the percent of under-scheduled load in the peak hour was, on average, under four percent in the day-ahead and under 2 percent in the hour-ahead.

Figure E.2 Summary of Load Scheduling Practices (Hour 16)



The fact that, on average, day-ahead load scheduling exceeded 95 percent suggests that there may be other factors influencing scheduling behavior. For example, the amount of forward scheduling in 2006 may be affected by a variety of California Public Utilities Commission

(CPUC) procurement guidelines which have had the effect of encouraging the state's major Investor Owned Utilities (IOUs) to forward contract for most or all of their projected energy needs. Additionally, while Resource Adequacy (RA) requirements in effect for 2006 only require that available RA capacity be made available to the CAISO, it is likely that many RA capacity contracts are coupled with energy contracts – such as energy tolling agreements – which allow the LSE to schedule energy from RA resources on a day-ahead basis.

System Resource Adequacy Requirements

In 2006, Resource Adequacy programs developed by the CPUC and other Local Regulatory Authorities (LRAs) became effective. These programs, developed pursuant to Assembly Bill 380, require that LSEs procure sufficient resources to meet their peak load along with appropriate reserves. RA programs support system and local grid reliability by creating a framework intended to promote new generation investment in California by providing generation resources a revenue source to contribute towards fixed cost recovery. The CAISO facilitates implementation of these RA programs through its Interim Reliability Requirements Program (IRRP), which defines how RA resources are made available to the CAISO prior to the implementation of MRTU.

Beginning in June 2006, the CPUC directed its jurisdictional LSEs to procure sufficient resources to cover 100 percent of their forecast load for each month, plus a 15 percent reserve margin. LSEs not under CPUC jurisdiction, mainly local publicly-owned utilities, meet roughly similar requirements determined by their respective LRAs. The procurement requirements for 2006 were entirely on a system-wide basis. There was no requirement in 2006 to procure resources based on capacity needs determined on a local basis. For 2007, LSEs under CPUC jurisdiction are required to obtain resources located within defined local areas based on their share of the forecast load within each CAISO Transmission Access Area, which equate to the old service territories of the investor owned utilities. Both the system and local requirements are important to reliability, short-term revenue adequacy, and to provide a framework for investment in infrastructure.

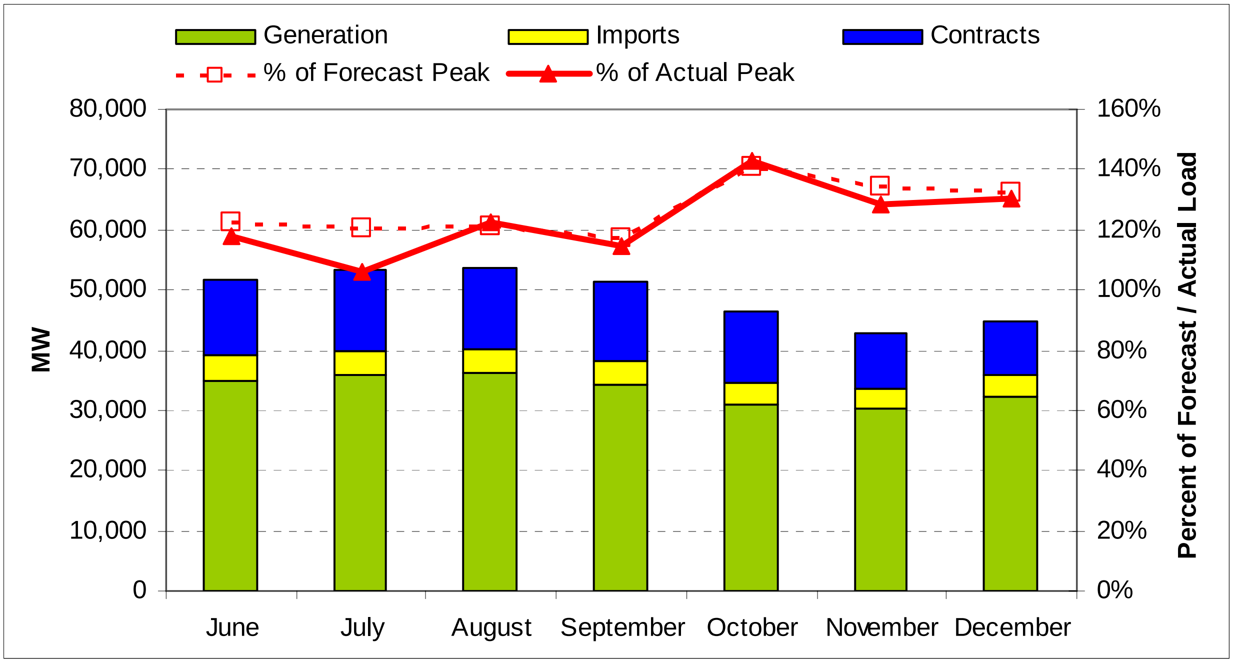
LSEs fully complied with the 2006 Interim Reliability Requirements Program for all months during the June to December time frame. Figure E.3 compares the available RA resources system-wide during June through December 2006 to the CAISO system summer peak forecast load and the actual summer peak load. As shown by Figure E.3, LSEs had met the capacity requirements in all months with total monthly capacity showings equal to approximately 120 percent of forecasted load for June through September and even higher percentages in the October through December time frame.[3] For the month of July 2006, capacity showings totaled 53,192 MW, which was 121 percent of the CAISO system summer peak forecast load of 44,026 MW, and 106 percent of the 50,270 actual system summer peak load (which was a CAISO record system peak).[4] Not shown explicitly in Figure E.3, but as a point of reference, LSEs subject to CPUC jurisdiction procured resources with a total capacity of 48,111 MW for July

[3] The percentages shown in Figure E.3 ("% of Forecast Peak" and "% of Actual Peak") are calculated by dividing the total capacity showing for each month by the forecasted or actual peak load for each month.

[4] The 44,026 summer peak load forecast is calculated as the 46,063 MW CAISO peak load forecast minus 2,037 MW of demand response resources, consistent with the procurement requirement calculation. All LSEs 53,192 MW resource capacity excludes 2,037 MW of demand response resources. The 50,270 MW actual system summer peak load includes the contribution of demand response resources.

2006, which was 128 percent of their forecast peak load of 37,537 MW.[5] Figure E.3 also summarizes the mix of RA resources that were available system-wide for the month of July, which included 35,927 MW of generation within the CAISO control area, 4,117 MW of imports, and 13,147 MW of Liquidated Damage (LD) contracts.

Figure E.3 Summary of System RA Compliance



Reliability Capacity Service Tariff (RCST)

Under terms of the IRRP taking effect in June 2006, all RA capacity that is available must be scheduled or made available to the CAISO for commitment through the CAISO's must-offer waiver denial process. Since RA units are eligible for capacity payments under bilateral contracts, IRRP tariff changes taking effect in June 2006 also specified that RA resources committed through the CAISO's must-offer process would be eligible to recover only minimum load operating costs from the CAISO and would no longer receive an additional payment for minimum load energy at the real-time energy price.

In recognition of the fact that RA and RMR resources may not be sufficient to meet all system reliability needs, CAISO continues to have the authority to commit other resources with Participating Generator Agreements through the must-offer waiver denial process. However, the IRRP specified that the CAISO could commit non-RA resources through the must-offer waiver process only if there were insufficient RA or RMR resources available to meet any local, zonal or system reliability needs. Any non-RA resources committed through the must-offer process continue to receive payments for minimum load operating costs along with an additional

[5] The 37,537 MW forecast peak load of CPUC-jurisdictional LSEs is calculated as the California Energy Commission's (CEC) 39,546 MW peak load forecast for July minus 2,009 MW of demand response resources. CPUC-jurisdictional LSEs' 48,111 MW resource capacity excludes 2,009 MW of demand response resources. (Values obtained from CPUC "2006 Resource Adequacy Report," Feb 2, 2007)

payment for minimum load energy at the real-time energy price. These non-RA units are now sometimes referred to as "FERC-MOO" units, due to the fact that they are subject to Must-Offer Obligation (MOO) under the must-offer provisions of the CAISO tariff approved by the Federal Energy Regulatory Commission (FERC), rather than a bilateral RA contract or RMR contract with the CAISO.

In addition, starting in June 2006, any non-RA resources committed through the must-offer process also became eligible to receive additional payments under the terms of proposed tariff changes filed by the CAISO along with certain other settling parties under an Offer of Settlement stemming from a 2005 complaint which alleged that compensation under the must-offer waiver process is unjust and unreasonable.

The Offer of Settlement proposed tariff changes, which were approved by FERC, establish a Reliability Capacity Services Tariff (RCST) under which any non-RA unit committed by the CAISO through the must-offer waiver process for reliability needs would be compensated with a daily capacity payment. The RCST settlement also provided the CAISO with the authority to designate non-RA units to provide services under the RCST as a "backstop" in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

Although final FERC approval of RCST provisions was not granted until February 2007, key provisions regarding the compensation of non-RA units committed by the CAISO through the must-offer process and allocation of these costs were ultimately approved with an effective date of June 1, 2006. Key provisions of the RCST include the following:

- **RCST Capacity Payments.** In addition to receiving minimum load costs, non-RA units designated as RCST are eligible to receive an RCST capacity payment. These capacity payments are equal to $73/kW-year, less a variable Peak Energy Rent (PER) amount that is calculated each month based on the potential net energy and ancillary services revenues that could be earned by a new peaking unit given actual CAISO market prices. This net RCST capacity payment is calculated on a monthly basis by allocating this annual fixed cost to each month using monthly percentages, which allocate a higher portion of annual fixed costs to summer months relative to other months of the year.

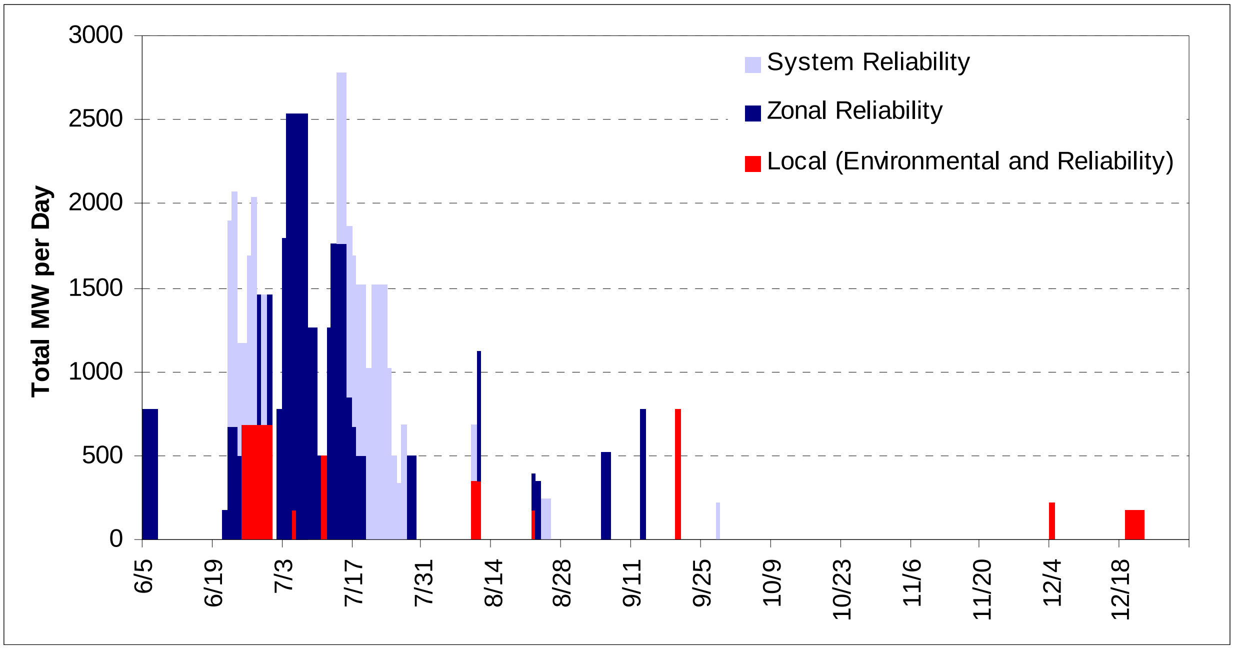
- **RCST Designations.** Any non-RA units designated as RCST units by the CAISO for one or more months are eligible for the monthly capacity payment described above. The RCST settlement also provides that if any non-RA unit is committed under the must-offer waiver process four separate days in any year, the CAISO would evaluate whether a significant change in grid operations had occurred that warrants making additional RCST designations.

- **Daily RCST Capacity Payments**. Any non-RA units committed through the CAISO's must-offer process are eligible for a daily RCST capacity payment equal to 1/17th of the monthly capacity payment described above. However, daily RCST capacity payments for any month may not exceed the total monthly capacity payment described above. Preliminary estimates provided by the CAISO indicate that approximately $10.6 million in daily RCST capacity payments under this provision occurred in 2006 due to non-RA units being committed through the must-offer waiver process, with over three-quarters of these costs occurring during periods of extremely high system loads in June through August.

- **Real Time Energy Mitigation Adder.** The RCST tariff provisions also include a potential $40/MWh payment adder for certain units that are mitigated under the current CAISO's local market power mitigation (LMPM) measures more than four 10-minute intervals in one day.[6] Preliminary calculations by the CAISO indicated that, from June though July, costs due to this potential $40 adder would total only about $23,000.

Figure E.4 shows the amount of non-RA generation capacity committed under the CAISO must-offer waiver process since June 2006 and demonstrates that the majority of non-RA commitments occurred during the peak summer period of late June through July.

Figure E.4 Non-RA Capacity Committed Under Must-Offer Waiver Process



Long-term Procurement Plans

In addition to addressing short-term capacity requirements through the Resource Adequacy program, the CPUC has also required that LSEs under its jurisdiction develop and file 10-year long-term procurement plans (LTPPs) designed to comply with any and all policy constraints and to adequately meet bundled customer load needs. The 2006 LTPPs will need to reflect all procurement related decisions from prior rule makings, including the following:

- Adopted Demand Response programs and attainment goals.

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[6] Under current LMPM measures, bids dispatched out-of-sequence for intra-zonal congestion or local reliability needs that exceed $50 or 200 percent of the real-time interval price are mitigated to their incremental reference price. Under the RCST tariff provisions, bids mitigated under these LMPM provisions may have up to $40/MWh added to their mitigated price if the unit is subject to LMPM more than four 10-minute intervals in one day. However, the $40/MWh adder is reduced if necessary so that the total price paid under LMPM does not exceed the original bid price.

- Procurement "loading order" as reflected in the state agencies' Energy Action Plan II and adopted by the CPUC.

- Identify the key planning decisions required to meet a renewable portfolio standard of 33 percent by 2020.

On December 11, 2006, CPUC jurisdictional entities submitted their long-term procurement plans to the CPUC. Intervener testimony was submitted on March 2, 2007, and reply testimony is due on April 9, 2007. The CAISO has been reviewing the LTPPs to determine whether the proposals raise any operational issues that parties should be aware of. The CPUC is expected to approve the LTPPs later in 2007.

Additionally, in a July 21, 2006 decision, the CPUC directed Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) to procure 1,500 MW and 2,200 MW of new generation, respectively, and to unbundle the capacity and energy products from this new generation. It was determined that PG&E needed 1,200 MW of new peaking generation and 1,000 MW of new peaking and dispatchable generation by 2010 and that SCE would have the option of a two track approach with a "fast-track" RFO for new generation coming on-line beginning mid-2009 and a "standard track" with expected on-line dates of 2012-2013. However, if SCE does not pursue all 1,500 MW under a fast track, it must justify to the CPUC why it is appropriate to pursue some of the generation under the standard track. Under this decision, the capacity of the new generation would be allocated to each LSE in the IOU's service territory and count towards its RA requirements. The costs of the capacity would be allocated similarly. The energy product will be auctioned off by a third party. The CPUC action was taken due to the urgency for new generation investment in California and the recognition that a more permanent long-term procurement structure, that effectively addresses the need for long-term procurement and retail competition, would not be completed for some time.

The implementation of the CPUC Resource Adequacy Program in 2006 coupled with implementation of Local Resource Adequacy Requirements and continued regulatory focus on utility long-term procurement are all positive developments for facilitating new generation investment in key areas of the grid and achieving other state energy policy objectives.

General Market Conditions

Demand

Loads in 2006 were significantly above those in 2005 both on an overall basis as well as a peak load basis. The significant increase in overall energy consumption was driven primarily by significantly higher load levels in June and July. Total energy consumption in June 2006 was approximately 12 percent higher than June 2005, primarily because June 2005 was an unusually cool month. July 2006 loads were 8 percent above July 2005 levels due to the extraordinary 3-week heat wave in July 2006. The record peak load was achieved on July 24, 2006 at 50,270 MW, shattering the previous peak load record of 45,597 MW that occurred on September 8, 2004. While these two months accounted for most of the increase in annual energy consumption, load levels for most months in 2006 were higher than 2005. Table E.1 shows two sets of annual load statistics for the CAISO Control Area, statistics based on actual loads, and statistics based on adjusted loads that reflect changes to the CAISO Control Area and adjustments for the 2004 leap year.

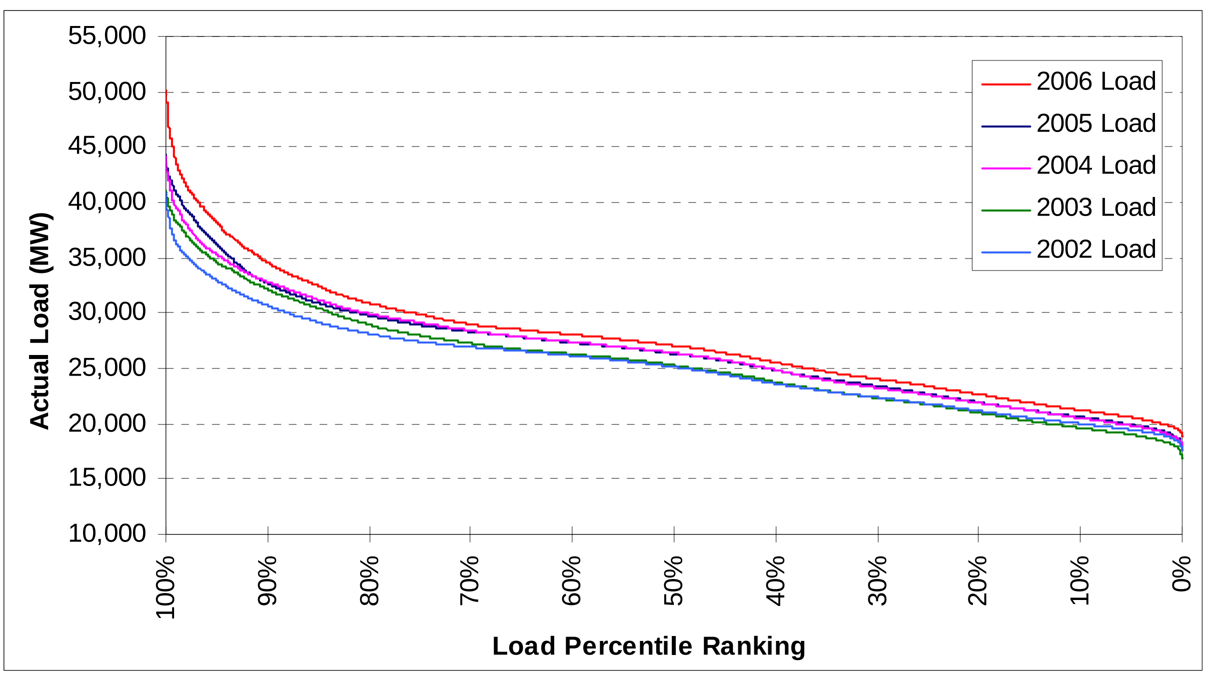
Table E.1 Load Statistics for 2002 – 2006*

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2002 Actual	26,548		232,612	42,352	
2003 Actual	26,334	-0.8%	230,735	42,581	0.5%
2004 Actual	27,303	3.5%	239,231	45,597	6.5%
2005 Actual	26,989	-1.2%	236,481	45,562	0.1%
2006 Actual	27,426	1.6%	240,303	50,270	9.3%
2002 Adjusted	25,143		220,278	40,979	
2003 Adjusted	25,459	1.2%	223,047	41,063	0.2%
2004 Adjusted	26,429	3.7%	231,542	44,209	7.1%
2005 Adjusted	26,477	0.2%	231,962	44,260	0.1%
2006 Adjusted	27,426	3.5%	240,303	50,270	12.0%

* Adjusted figures are normalized to account for day of week, changes in the CAISO Control Area footprint, and the 2004 leap year.

Figure E.5 depicts load duration curves for each of the last five years and demonstrates the significant increase in load during 2006. Most striking in 2006 is the percentage of hours that load exceeded 40,000 MW, which used to be considered an extreme peak level. In 2006, hourly loads exceeded 40,000 MW in 3.2 percent of the total annual hours, compared to 1.6 percent and .8 percent in 2005 and 2004, respectively.

Figure E.5 Hourly Load Duration Curves



Supply

Approximately 633 MW of new generation began commercial operation within the CAISO Control Area in 2006. The majority of new capacity in the north was wind generation (150 MW out of 199 MW total in the north). Approximately 1,535 MW of generation capacity was removed from service in 2006, the majority of which was located in the SP15 congestion zone. The most notable of the retirements were the Mohave generating units (1,320 MW of effective capacity), which were the only coal-powered resources in the CAISO Control Area.[7]

Table E.2 below shows an annual accounting of generation additions and retirements since 2001, with projected 2007 changes included and totals across the seven years depicted. There was a 902 MW net decline in installed generation in the CAISO control area in 2006, the first net decline in installed generation in the post energy crisis period. The total net increase in installed generation in the CAISO control area over the seven years spanning 2001 – 2007 is approximately 10,300 MW. When accounting for an estimated 2 percent load growth over the same seven year period of approximately 6,200 MW, the supply margin increased by roughly 4,100 MW since the energy crisis.

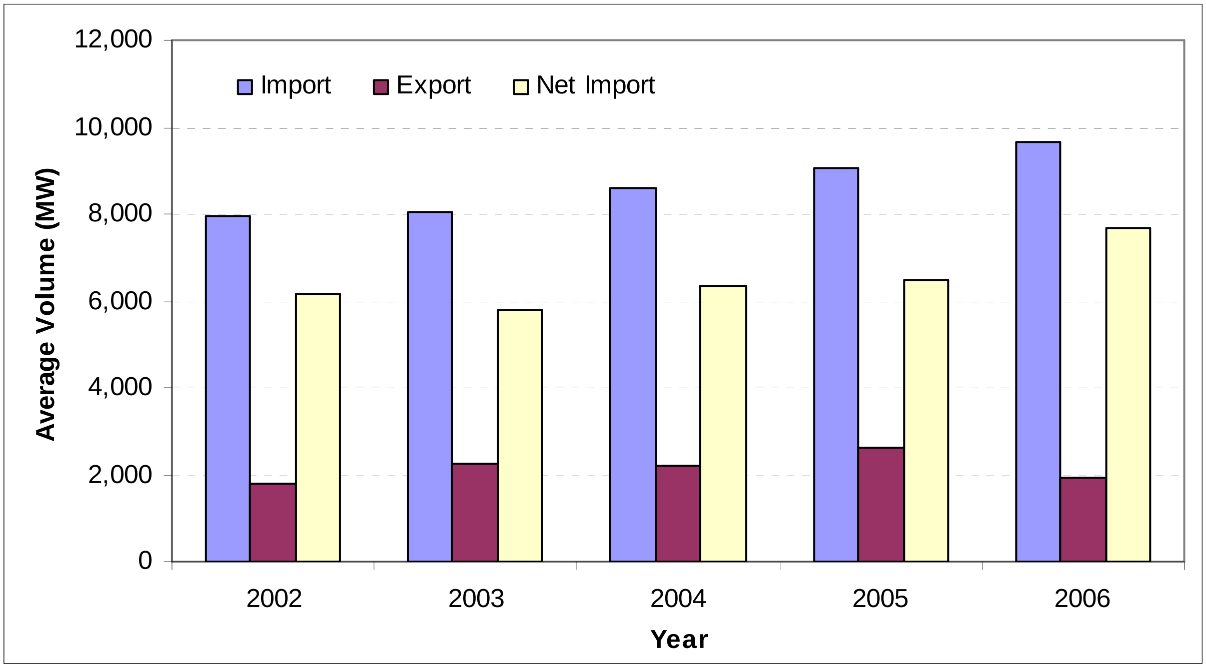
Table E.2 CAISO Generation Additions and Retirements

	2001	2002	2003	2004	2005	2006	Projected 2007	Total Through 2007
SP15								
New Generation	639	478	2,247	745	2,376	434	1,348	8,267
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	(4,280)
Forecasted Load Growth*	148	500	510	521	531	542	553	3,305
Net Change	**491**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**795**	**682**
NP26								
New Generation	1,328	2,400	2,583	3	919	199	136	7,568
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	2,895
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(303)**	**3,438**
ISO System								
New Generation	1,967	2,878	4,830	748	3,295	633	1,484	15,835
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	(5,515)
Forecasted Load Growth*	537	897	915	934	953	972	991	6,199
Net Change	**1,402**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**493**	**4,121**

Imports continue to play a key role in meeting demand. Figure E.6 shows average annual gross imports, exports, and net imports for the five-year period covered by 2002-2006. Average hourly imports and net imports increased significantly in 2006 by approximately 6 percent and 19 percent, respectively. The increase is predominately attributed to a higher level of imports from the Pacific Northwest brought on by the exceptionally high levels of hydroelectric generation from this region. Additionally, average exports declined in 2006 by approximately 25 percent, which helped to increase the average net-import amount. Figure E.6 also demonstrates a four-year trend of increasing imports (both gross and net) indicating a growing reliance on imports to meet energy demands within the CAISO Control Area.

[7] Though the Mohave coal-fired generating units are physically located outside of California (Southern Nevada), they were incorporated into the CAISO Control Area, which is why they are included in Table E.2.

Figure E.6 Average Annual Imports, Exports, and Net Imports (2002-2005)



Generation Outages

Figure E.7 depicts monthly average planned and forced outages between 2003 and 2006. In 2006, planned outages were high during the first five months of the year (compared to past years) and both planned and forced outages were exceptionally high in April 2006. In this month, three nuclear resources were out for refueling (although two of these seasonal refueling outages were technically classified as forced outages), and several other large combined-cycle and steam resources were also out for annual maintenance. With plentiful hydroelectric power available at this time, the multiple planned outages during this period did not impose any reliability issues.

Given the aggressive maintenance schedule in the first half of 2006, forced outages were relatively modest in July and August. The low level of forced outages in July 2006 is remarkable given the extraordinary heat wave that resulted in power plants having to remain online under extremely hot weather conditions for most of July.

Figure E.7 Monthly Average Planned and Forced Outages (2003 – 2006)

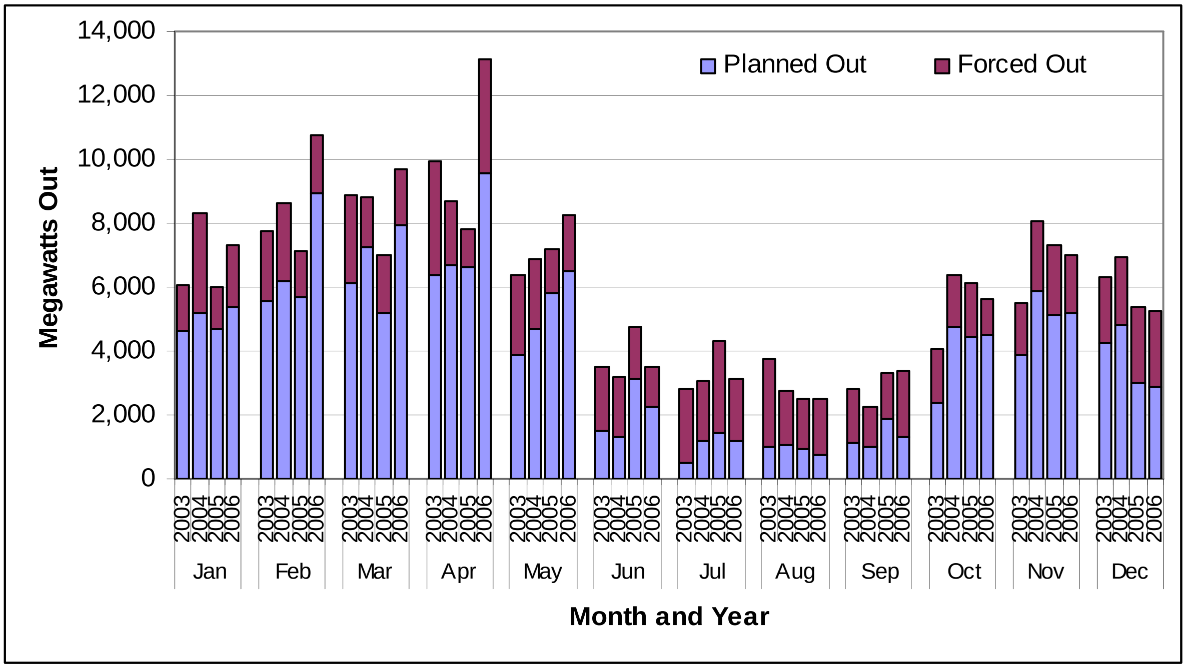
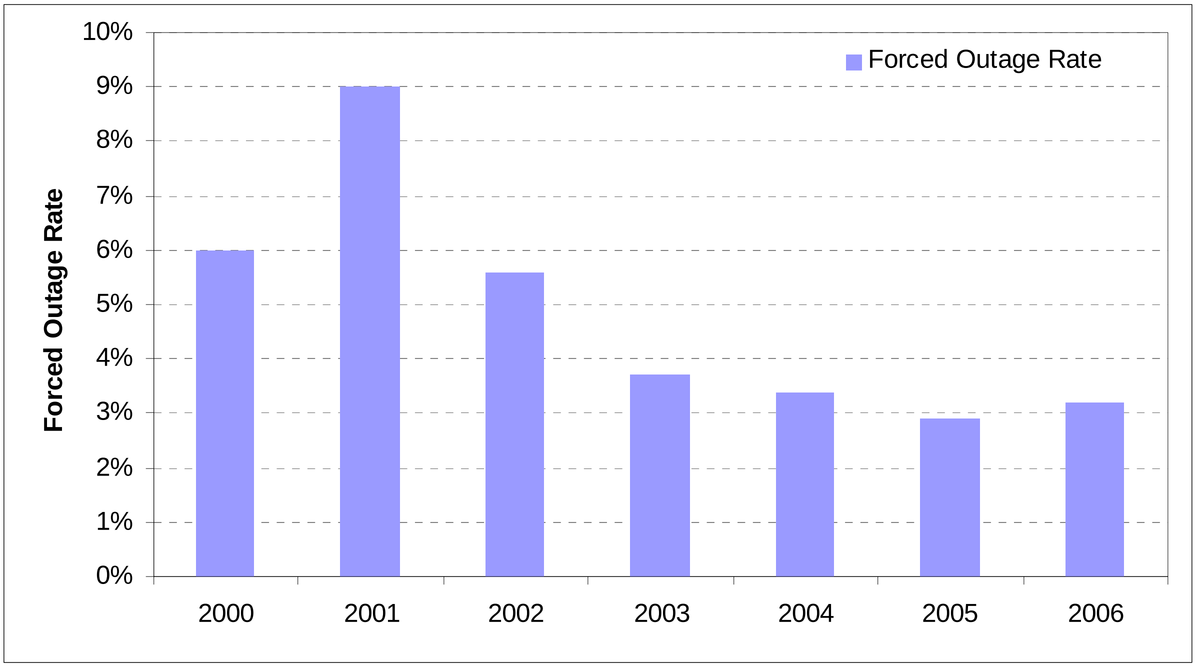


Figure E.8 compares annual forced outage rates since 2000. Over the past three years, annual forced outage rates have averaged approximately 3 percent, a dramatic improvement over the levels experienced during the energy crisis (2000-2001). This change can be primarily attributed to the substantial increase in new generation since 2000, which has a decreasing effect on overall outage rates.

Figure E.8 Annual Forced Outage Rates (2000 – 2006)



Short-term Energy Market Performance

The significant number of long-term contracts entered into by the state of California in 2001 and by LSEs since then combined with the large amount of new generation added to the Western energy markets provided effective market power mitigation in the 2006 short-term energy markets. When LSEs are adequately supplied though longer-term energy arrangements, they substantially reduce their exposure to market power in the spot market and, more generally, high spot market prices. Adequate long-term energy contracting also reduces incentives for supply resources to try to elevate spot prices. Market power mitigation measures are in place to reduce the risk of market manipulation and opportunistic exploitation of contingencies and extreme circumstances. However, mitigation should not excessively dampen spot market volatility, as that may encourage LSEs to reduce their forward contract cover and rely more on the spot markets.

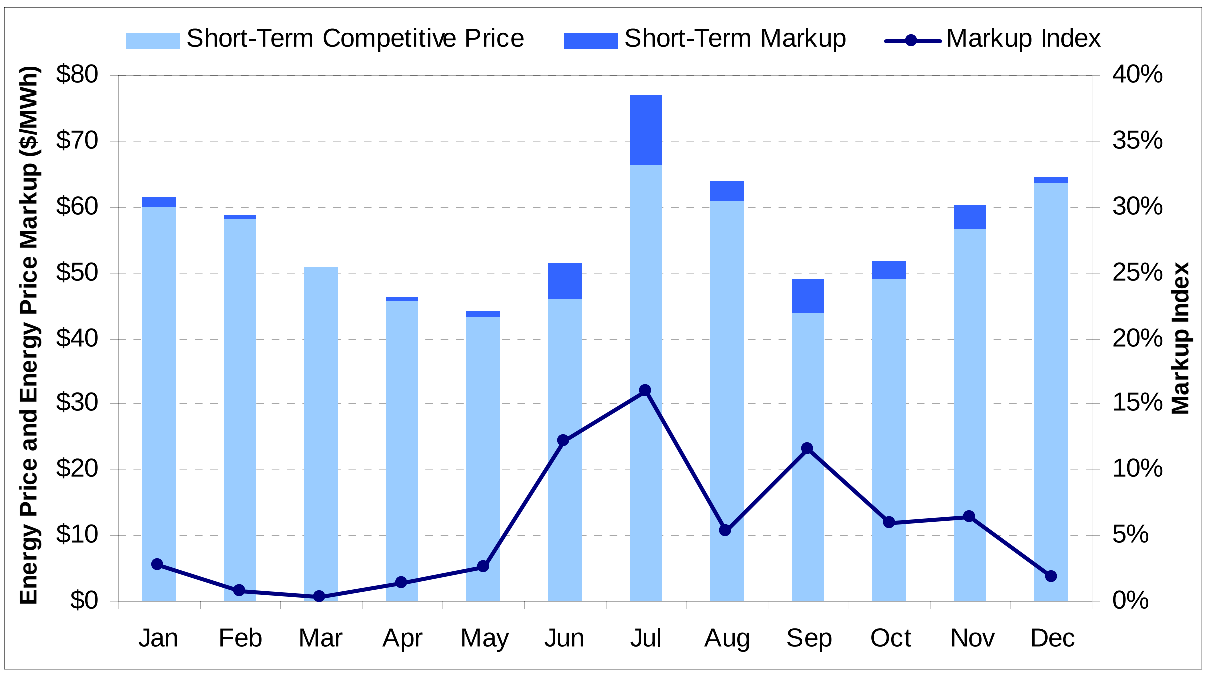
Estimated Mark-up of Short-term Bilateral Transactions

Having no formal forward energy market makes a comprehensive review of competitiveness difficult due to lack of reporting on transactions in the short-term bilateral energy market. The CAISO has estimated mark-ups for short-term spot market transactions based on data collected from Powerdex, Inc.,[8] an independent energy information company featuring the first hourly wholesale power indexes in the WECC, and short-term purchase cost information provided by the state's three investor owned utilities. The competitive benchmark prices are calculated using a production cost model that determines the hourly system marginal cost by incorporating

[8] http://www.powerdexindexes.com/.

detailed generation unit and system cost information. Figure E.9 shows the monthly average of estimated hourly mark-ups for short-term bilateral transactions. A detailed description of the methodology and assumptions used in the analysis can be found in Chapter 2. Short-term average monthly mark-ups in 2006 ranged between .2 percent in March to a high of 16 percent in July. Overall, the index indicates that short-term wholesale energy markets produced competitive outcomes in 2006 with mark-ups averaging around 5 percent. The high mark-up in July reflects the severe heat wave, which increased spot bilateral prices at or near the $400/MWh bid cap in numerous hours. Though mark-ups were significant in July, they were highly correlated with expected scarcity conditions and appear to have had minimal cost impacts to California LSEs due to the high level of hedging, which minimized spot market exposure.

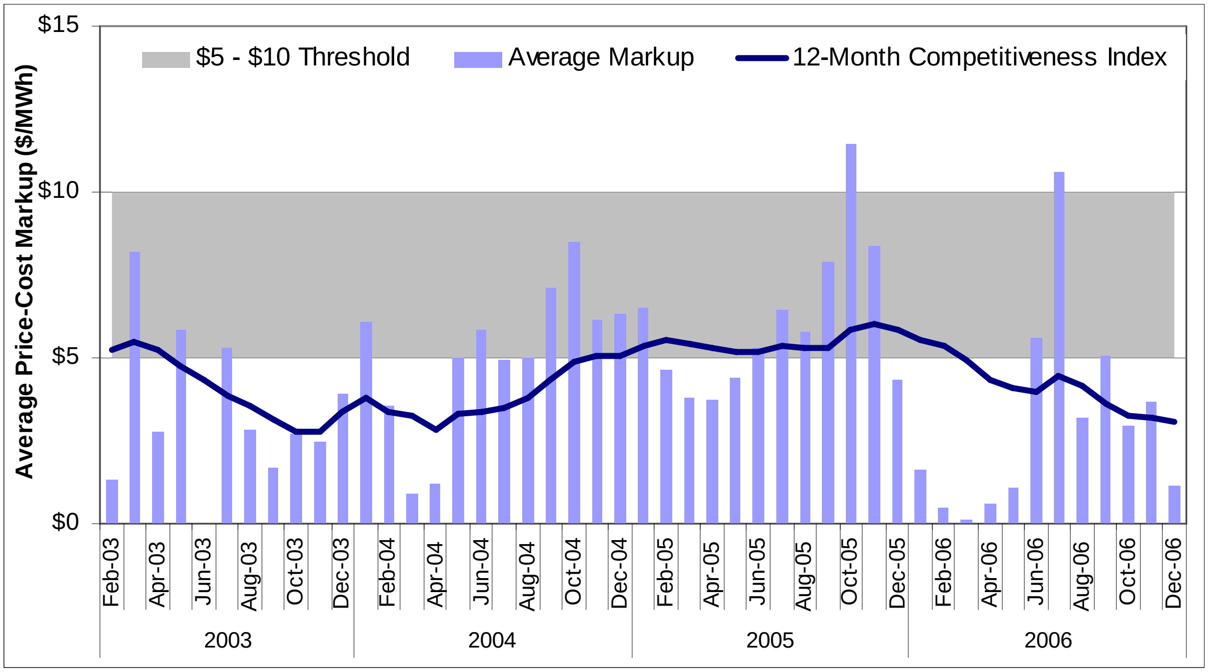
Figure E.9 Short-term Price-Cost Mark-up Index (2006)



Twelve-Month Market Competitiveness Index

Another index the CAISO uses to evaluate market competitiveness is the 12-month competitiveness index. The CAISO developed the index to measure market outcomes over a long period of time and to compare them to expected competitive market outcomes. The index is a volume-weighted twelve-month rolling average of the short-term energy mark-up above estimated competitive baseline cost. The index provides a benchmark to measure the degree of market power exercised in the California short-term energy market during a 12-month period. Experience has shown that the market is workably competitive when the index is within a range of approximately $5 to $10/MWh or below. The index, which crossed this threshold in May 2000 and remained very high during the California energy crisis, served as a barometer for uncompetitive market conditions. The index moved back into the competitive range in May 2002 and has remained in that range through 2006. This indicates that the short-term energy market in California that stabilized in late 2001 has produced fairly competitive results over the past five years. Figure E.10 below shows the market competitiveness index values for the past four years (2003-2006).

Figure E.10 Twelve-Month Market Competitiveness Index (2003-2006)



Structural Measure of Market Competitiveness: Residual Supplier Index

The Residual Supplier Index (RSI) measures the market structure rather than market outcomes. This index measures the degree to which suppliers are pivotal in setting market prices. Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the total demand cannot be met absent the supplier's capacity. Such a case would result in an RSI value less than 1. When the largest suppliers are pivotal (an RSI value less than 1), they are capable of exercising market power. In general, higher RSI values indicate greater market competitiveness.

The RSI levels in 2006 were generally similar to the past several years (2003-2005) with two notable differences. First, using an RSI level of 1.1 to compare between years,[9] in 2006 the RSI levels were less than 1.1 in more hours than in the previous three years, suggesting greater market power potential compared to past years – albeit moderately so. This result is mainly due to the July 2006 heat wave which resulted in very tight supply margins in numerous hours that translated into lower RSI values. Second, 2006 also experienced some of the highest RSI values of the past several years. This result is reflective of the abundance of hydroelectric generation during the first half of the year. Overall, the RSI levels in 2006 are consistent with the market outcomes and short-term energy market price-cost mark-ups observed in 2006.

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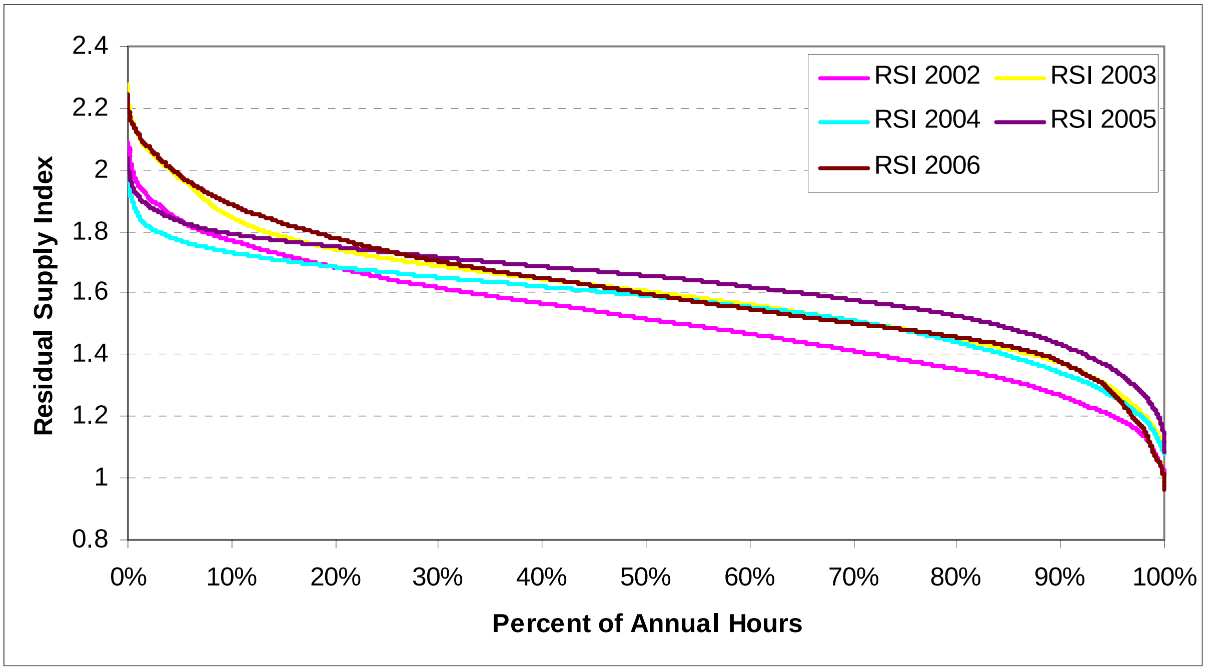
[9] Historically, market power can be prevalent with an RSI of 1.1 due to estimation error and the potential for tacit collusion among suppliers.

Figure E.11 Hourly Residual Supply Index (2002-2006)



Revenue Adequacy of New Generation

Another benchmark often used for assessing the competitiveness of markets is the degree to which prices support the cost of investment in new supply needed to meet growing demand and replace existing capacity that is no longer economical to operate. Typically, new generation projects would not go forward without having the output of the plant secured through long-term contractual arrangements that would cover most, if not all, of the plant's fixed costs. However, given lack of information on prices paid in the current long-term bilateral energy and capacity markets, our analysis examined the extent to which spot markets contributed to the economics of investment in new supply capacity given observed prices over the last four years. Clearly a plant would not be built on the expectation of full cost recovery by selling solely into the CAISO's real-time imbalance energy and ancillary service markets. However, this analysis does show the trend in the level of contribution towards a new unit's fixed costs that could have been recovered in these markets over the year. Chapter 2 includes a detailed explanation of the costs and assumptions used in the analysis.

The assessment of the potential revenues a new generation facility (combined cycle or combustion turbine) could have earned in California's spot market in 2006 indicates potential spot market revenues fell short of the unit's annual fixed costs (Figure E.12 and Figure E.13). While this result is consistent across the past four years, there is a favorable three year trend evident in the combined cycle analysis (Figure E.12). Specifically, the combined cycle analysis shows a trend of net spot market revenues increasing for both Southern (SP15) and Northern (NP15) California with estimated net revenues in 2006 approaching the break-even point of $90 kW-year. The increase in 2006 is primarily attributed to a higher bid cap of $400/MWh and very high day-ahead spot prices during the July 2006 heat wave. While estimated net spot market revenues also increased in 2006 for a new combustion turbine (Figure E.13), net revenues were still well below the $78/kW-year estimated break-even point.

Figure E.12 Financial Analysis of New CC Unit – SP15 (2003-2006)

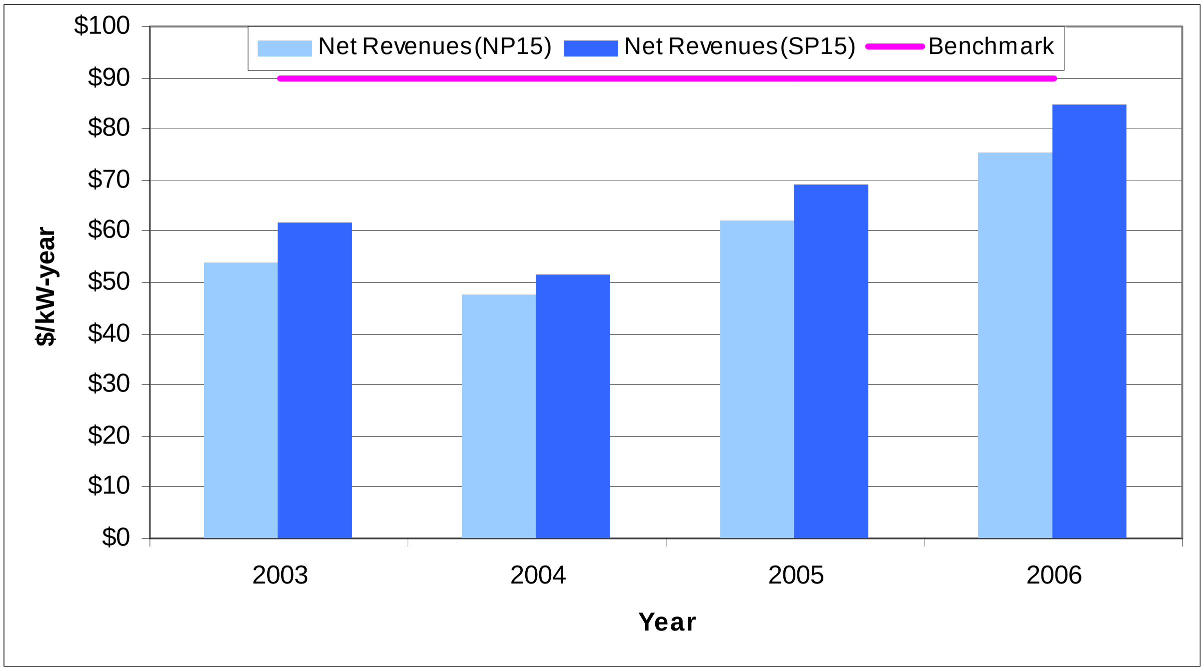
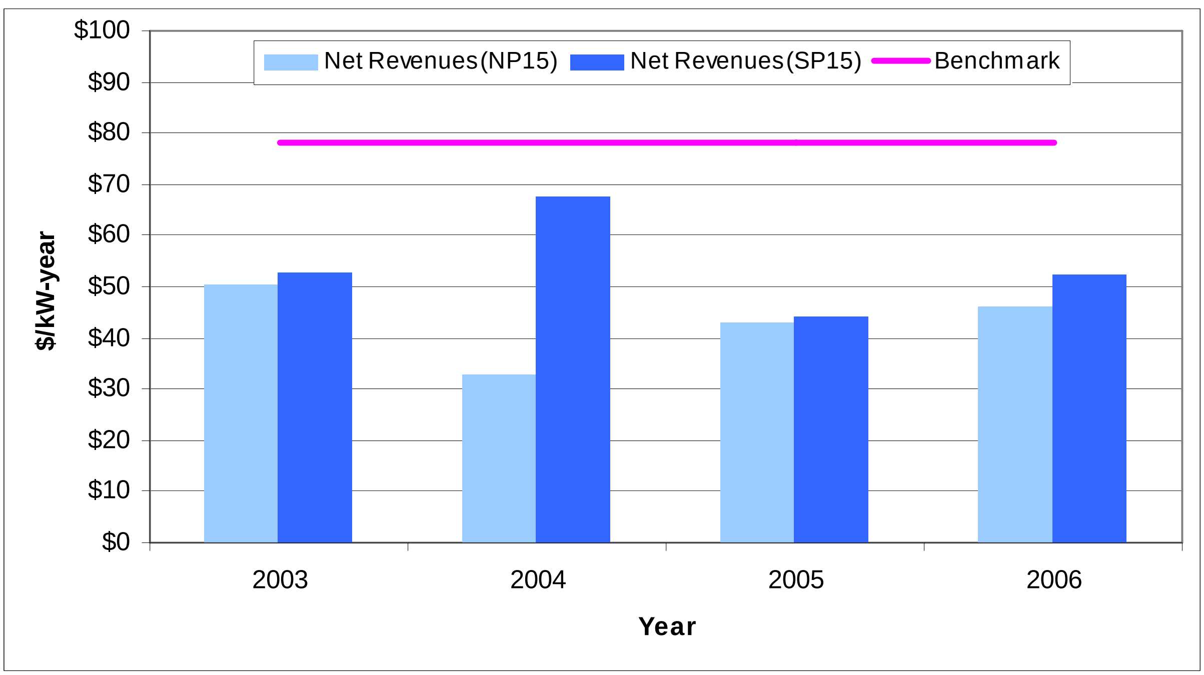


Figure E.13 Financial Analysis of New CT Unit (2003-2006)



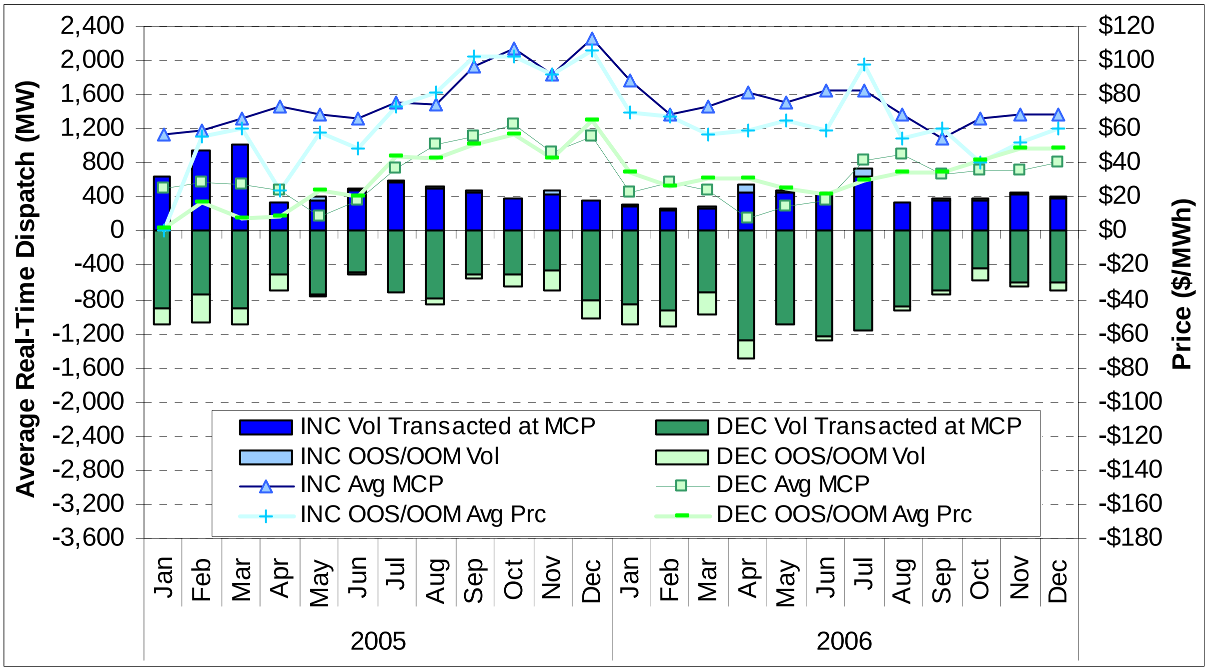
Given the need for new generation investment in California, the finding that estimated spot market revenues failed to provide for fixed cost recovery underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year (i.e., the generation level from a market efficiency standpoint was adequate in 2006) but the net revenues earned in 2006 is not indicative of future market revenue opportunities, which is the primary driver for new investment. In any case, future market design features that could provide better price signals for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation on February 1, 2008, will provide some of these elements (LMP, some degree of scarcity pricing). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) should also be seriously considered for future adoption. In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and similar programs for non-CPUC jurisdictional entities.

Real Time Energy Market

For the fifth year in a row, significant forward scheduling by LSEs resulted in low imbalance energy volumes throughout 2006 (Figure E.14). Real-time balancing energy was again overwhelmingly in the decremental direction as a high level of forward scheduling plus unscheduled energy from units committed under the must-offer obligation and excessive levels of hydroelectric generation resulted in frequent over-generation in the real-time imbalance energy market. As shown in Figure E.14, the average hourly levels of decremental dispatches were particularly high in the first half of 2006, averaging close to 1,200 MWh.

Monthly average prices in 2006 for periods when the CAISO was issuing incremental energy dispatches were stable, averaging between $60 and $80/MWh for most of the year. Average monthly prices for periods when the CAISO was issuing decremental dispatches were significantly lower, particularly during the first half of 2006 when demand for decremental energy bids was greatest. During this period, energy prices for decremental dispatches averaged around $20/MWh but increased in the second half of 2006 to approximately $40/MWh.

Figure E.14 Monthly Average Real-time Prices and Volumes (2005-2006)



Competitiveness of Real-time Energy Market

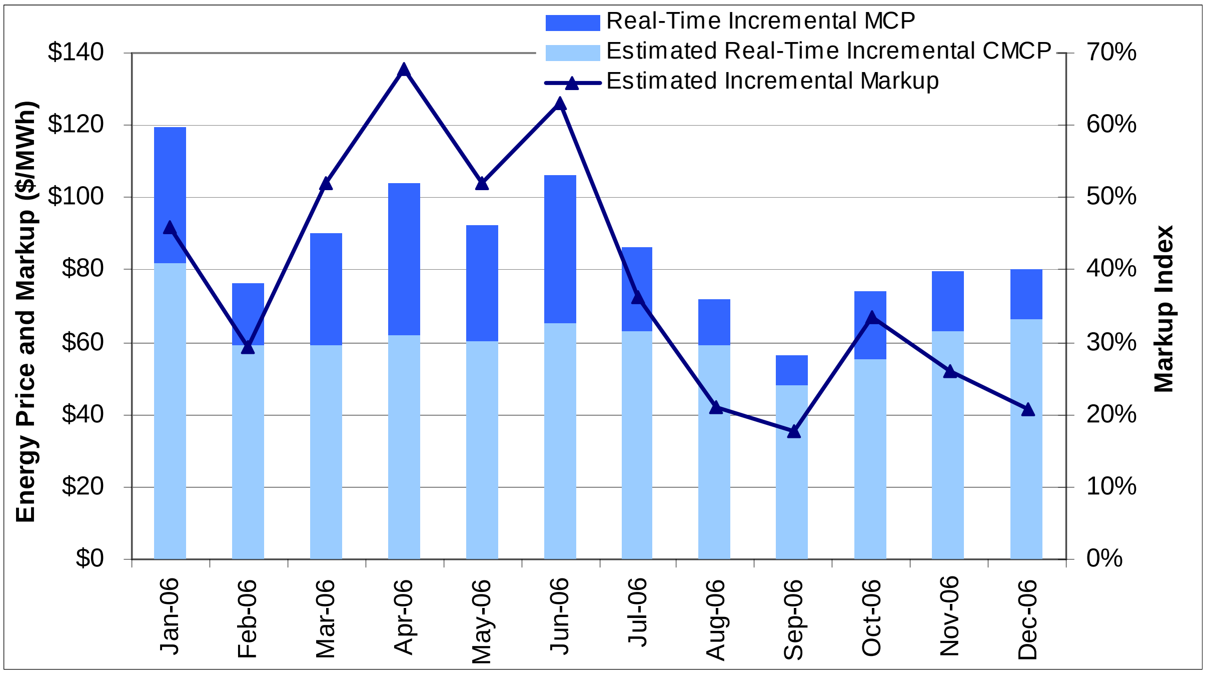
The CAISO uses a real-time price-to-cost mark-up index to measure market performance in the Real Time Market. This index compares Real Time Market prices to estimates of real-time system marginal costs. It excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[10] It is important to note that an index based upon the extremely small volume of transactions in the Real Time Market is not indicative of overall wholesale market competitiveness. Nonetheless, it provides a useful metric for Real Time Market performance.

Throughout 2006, estimated monthly average mark-ups in the Real Time Market were significantly higher than 2005, averaging approximately 40 percent throughout the year, compared to approximately 12 percent in 2005. The significant increase can be attributed to both a higher energy bid cap ($400/MWh vs. $250/MWh) and a much higher frequency of price spikes. The increase in price spikes was most pronounced in the first half of 2006 and was driven primarily by an abundance of hydroelectric generation which reduced the number of thermal generation units on-line and, in turn, the supply of 5-minute dispatchable energy bids to the Real Time Market. The abundance of hydroelectric generation created other real-time operational challenges in terms of managing loop flow, which also contributed to high imbalance energy demands and price spikes. While the unusually high mark-ups suggest a lack of market competition, it is important to note that the extremely small volumes of energy clearing this market (typically less than 2 percent of the load) coupled with a limited supply of 5-minute

[10] The original real-time price-cost mark-up index used system marginal cost based on all resources available for day-ahead scheduling. That competitive benchmark is more applicable to measure competitiveness of day-ahead and short-term energy markets. Only a subset of those resources is used in the calculation of the real-time mark-up.

dispatchable bids makes this market extremely volatile.[11] High volatility of both price and dispatch quantities coupled with overall low market clearing volumes serve as disincentives for additional supply to enter the market. Given the very small market volumes and high volatility observed in the CAISO Real Time Market, the competitiveness of the day-ahead spot bilateral market is a much more indicative measure of overall spot market competitiveness and as reported above, the estimated mark-ups in the day-ahead spot market were much lower and overall indicate that the spot market was workably competitive in 2006.

Figure E.15 Monthly Estimated Mark-up for Real Time Incremental Imbalance Energy Market



Real-time Congestion (Intra-Zonal)

Intra-zonal congestion occurs when power flows overload the transfer capability of grid facilities within the congestion zones that are modeled and managed in the CAISO day-ahead and hour-ahead congestion management market. Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated with insufficient transmission to allow access to competitively priced energy. Intra-zonal congestion can also occur due to generation pockets in which generation is clustered together with insufficient transmission to allow the energy to flow out of the pocket area. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket. Typically, there is very limited competition within load or generation pockets, since just one or two suppliers own the bulk of generation within such pockets. As a result, intra-zonal congestion is closely intertwined with the

[11] It is important to note that real-time imbalance energy markets are inherently volatile and thus the volatility observed in the CAISO Real Time Market is not necessarily an indication of market design deficiencies.

issue of locational market power. Methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise locational market power.

One of the major success stories in 2005 was the sharp reduction in intra-zonal congestion costs. In 2005, intra-zonal congestion costs totaled $222 million,[12] compared to $426 million in 2004, representing a 48 percent decrease (Table E.3). Intra-zonal congestion cost is comprised of three components: 1) MLCC for units denied must-offer waivers due to local constraints, 2) real-time RMR costs, and 3) real-time out-of-sequence (OOS) redispatch costs. For 2006, estimated total intra-zonal congestion declined further to $207 million. The MLCC for units committed for local reliability needs dropped slightly in 2006 to $109 million, compared to $114 million in 2005. Real-time redispatch costs associated with OOS dispatches also declined from $36 million in 2005 to $17 million in 2006. However, these reductions were offset by an increase in real-time RMR dispatches from $72 million in 2005 to $80 million in 2006, resulting in total intra-zonal congestion costs for 2006 of $207 million (compared to $222 million in 2005). Though not shown in Table E.3, it should be noted that total RMR dispatch cost (day-ahead and real-time) did decline significantly in 2006 from approximately $254 million in 2005 to $168 million in 2006, a 34 percent decrease. However, because day-ahead RMR dispatches are for a variety of local reliability needs (e.g., voltage support, contingencies, etc.), they are not considered in this analysis as intra-zonal congestion costs. The relatively low levels of intra-zonal congestion costs over the past two years as well as the decline in total RMR costs is the result of various transmission enhancements in 2005 and 2006 that were targeted to address frequently congested areas.

Table E.3 Comparison of 2005 and 2006 Monthly Intra-zonal Congestion Costs by Category ($/million)

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**
Jan	$ 12	$ 8	$ 10	$ 3	$ 3	$ 13	$ 4	$ 6	$ 4	$ 19	$ 17	$ 27
Feb	$ 13	$ 4	$ 8	$ 4	$ 3	$ 15	$ 7	$ 3	$ 2	$ 24	$ 10	$ 25
Mar	$ 20	$ 3	$ 11	$ 4	$ 5	$ 13	$ 8	$ 3	$ 3	$ 32	$ 11	$ 27
Apr	$ 18	$ 6	$ 27	$ 4	$ 5	$ 8	$ 5	$ 3	$ 6	$ 27	$ 14	$ 41
May	$ 22	$ 14	$ 12	$ 3	$ 5	$ 3	$ 4	$ 2	$ 1	$ 29	$ 21	$ 16
Jun	$ 25	$ 7	$ 15	$ 3	$ 2	$ 4	$ 2	$ 0	$ 0	$ 30	$ 9	$ 19
Jul	$ 29	$ 13	$ 14	$ 6	$ 5	$ 2	$ 11	$ 1	$ 0	$ 46	$ 19	$ 17
Aug	$ 29	$ 14	$ 5	$ 5	$ 9	$ 3	$ 15	$ 1	$ 0	$ 49	$ 24	$ 8
Sep	$ 23	$ 8	$ 3	$ 4	$ 6	$ 2	$ 12	$ 3	$ 0	$ 39	$ 17	$ 5
Oct	$ 21	$ 13	$ 1	$ 4	$ 8	$ 3	$ 18	$ 4	$ 1	$ 43	$ 25	$ 5
Nov	$ 29	$ 12	$ 1	$ 5	$ 5	$ 6	$ 9	$ 6	$ 0	$ 43	$ 23	$ 7
Dec	$ 33	$ 11	$ 2	$ 4	$ 16	$ 7	$ 8	$ 5	$ 0	$ 45	$ 32	$ 9
Total	**$ 274**	**$ 114**	**$ 109**	**$ 49**	**$ 72**	**$ 80**	**$ 103**	**$ 36**	**$ 17**	**$ 426**	**$ 222**	**$ 207**

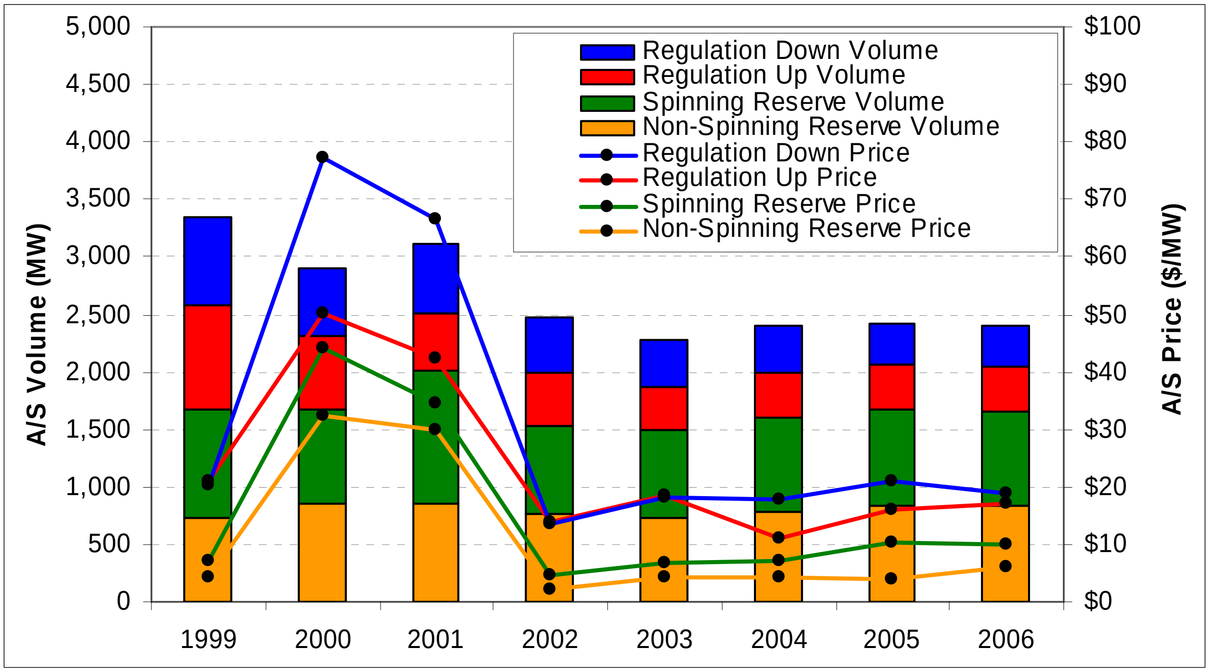
Ancillary Services Market

In the Ancillary Service Markets, prices were stable in 2006 and very similar to 2005. Overall, A/S prices increased 4 percent from a weighted average price of $10.72/MW in 2005 to

[12] In last year's report, total intra-zonal congestion costs of $203 million were reported in 2005. However, this estimate was based on preliminary settlement information for November and December 2005. The $222 million estimate for 2005 shown here reflects final settlement data for those months as well as other settlement corrections, which in total, amount to an increase of $19 million over last year's reported estimate. A similar issue may occur next year with regard to the reported costs for 2006.

$11.12/MW in 2006. The average volume of each ancillary service purchased was quite similar to previous years (Figure E.16). Bid insufficiency, in terms of the number of hours there were insufficient ancillary service bids to meet the CAISO requirements for ancillary services, was down considerably from 2005 in all the Ancillary Service Markets (Table E.4). The majority of the bid insufficiency of Regulation Reserves occurred during the spring months of 2006. During these periods of heavy hydro flows, hydroelectric generators tend to sell large volumes of energy cheaply, which essentially creates a disincentive for would-be non-hydroelectric suppliers of Downward Regulation to be online. Most of the Spinning and Non-Spinning bid insufficiencies occurred during the summer peak months.

Figure E.16 Annual A/S Prices and Volumes, 2000-2006



While the number of hours of bid insufficiency declined in 2006, when bid insufficiency did occur, the average MW amount of deficiency was greater than in 2005. Table E.4 shows that the average amount of bid insufficiency (measured as percent of the total requirement) increased from 7 percent in 2005 to 13 percent in 2006.

Table E.4 Ancillary Service Bid Insufficiency

	Number of Hours With Shortage				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2005	163	135	279	107	684
2006	159	110	145	113	527
Percent Δ	-2%	-19%	-48%	6%	-23%

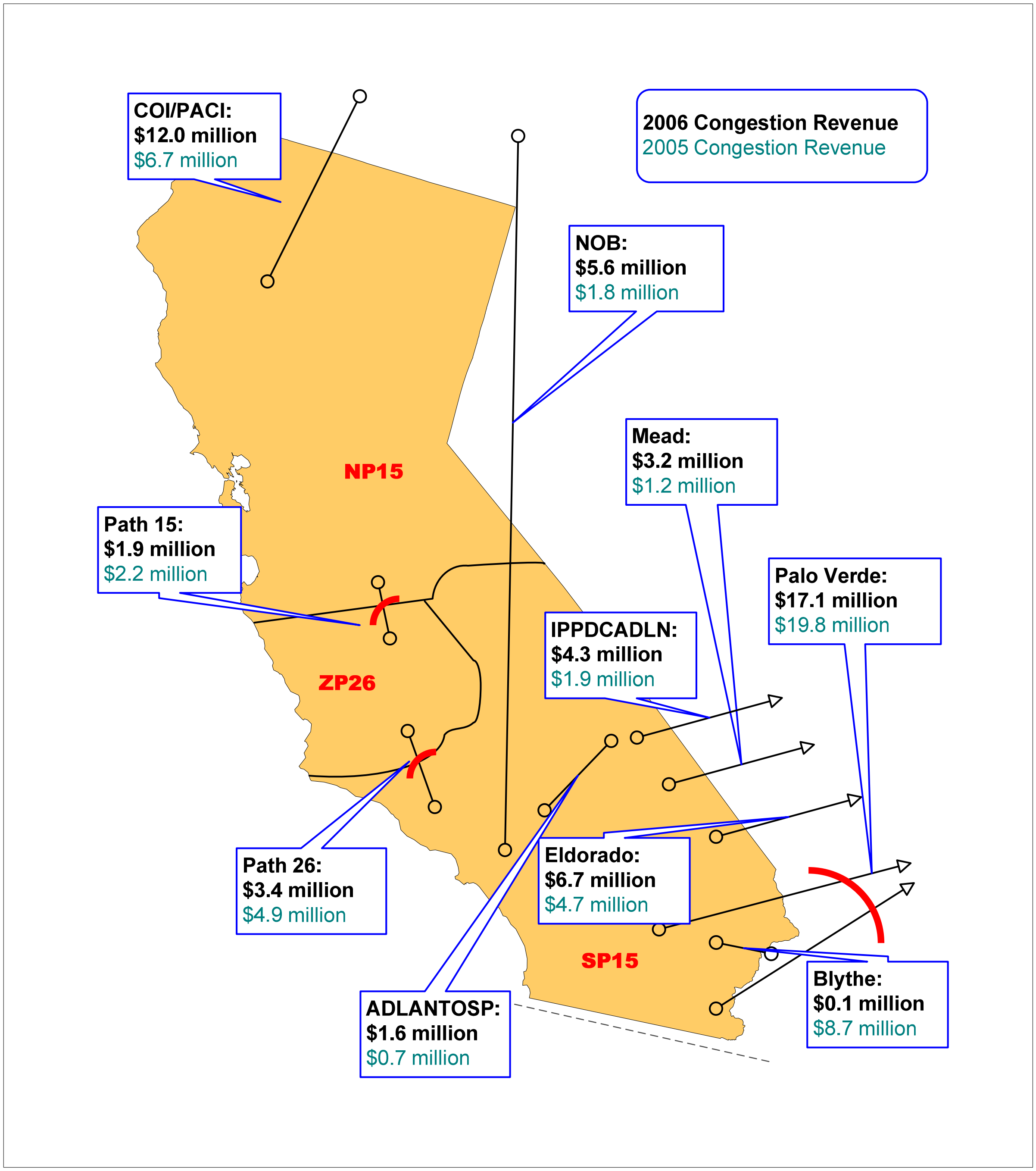
	Average Percent of Requirement Short				
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2005	9%	14%	5%	6%	7%
2006	21%	16%	8%	15%	13%

Inter-Zonal Congestion Market

The CAISO Inter-Zonal Congestion Management Market was also generally stable and competitive in 2005. Total inter-zonal congestion costs in 2006 were $56 million, slightly higher than the $54.6 million in 2005. Figure E.17 shows the total annual congestion costs for the most commonly congested paths in 2005 and 2006. Congestion costs on Path 15 went from $2.2 million in 2005 to $1.9 million in 2006. Not surprisingly, Palo Verde continued to have the highest congestion costs in 2006 at $17.1 million (compared to $19.8 million in 2005, which was also the highest). Congestion costs on COI/PACI increased to $12 million in 2006 (compared to $6.7 million in 2005).

The two most frequently congested transmission paths in 2005, the Pacific AC Inter-tie (PACI) from the Northwest (formerly known as the California-Oregon Inter-tie (COI) prior to the separation of the California-Oregon Transmission Project (COTP) from the CAISO grid) and the Palo Verde branch group from the Southwest, remained the top two congested paths in 2006 with COI being congested in 18 percent of the hours in the Day Ahead Market (compared to 18 percent in 2005) and Palo Verde congested in 15 percent of the hours (compared to 23 percent in 2005).

Figure E.17 Major Congested Inter-ties and Congestion Costs



Summary and Conclusions

Overall, the CAISO markets and short-term bilateral energy markets were stable and competitive in 2006. The markets were tested to the limit during the extreme heat wave in July and performed remarkably well. This performance reflects the significant strides that California has made since the energy crisis both in terms of infrastructure enhancements (transmission and generation) as well as in long-term power contracting. Long-term power contracting provides a number of critical benefits to the market. First, it protects LSEs from spot market volatility (i.e., is an important hedging tool). Second, it shifts spot market risk to the supply side of the market and in so doing largely reduces incentives for suppliers to exercise market power. Finally, it provides a means for facilitating new generation investment. When load is effectively hedged, periodic price spikes, such as occurred during the July heat wave, impose manageable costs to load and provide important market benefits such as incentives to avoid generation forced outages, revenues for generation fixed cost recovery, and market prices that encourage demand response programs.

While five consecutive years of stable and competitive market performance is encouraging, the industry must remain vigilant in addressing its ever growing infrastructure needs. Low levels of new generation investment in Southern California coupled with unit retirements and significant load growth has created reliability challenges for this region during the peak summer season. This trend has resulted in a higher reliance on imported power from the Southwest, Northwest, and Northern California. This dependence on imports, coupled with tight reserve margins, makes Southern California very vulnerable to reliability problems should there be a major transmission outage. Moreover, much of the existing generation within Southern California is comprised of older facilities that are prone to forced outages, especially under periods of prolonged operation as occurred during the extraordinarily long heat wave in July. Additional new generation investment and re-powering of older existing generation facilities would significantly improve summer reliability issues in Southern California. The implementation of the CPUC Resource Adequacy Program in 2006 coupled with implementation of Local Resource Adequacy Requirements and continued regulatory focus on utility long-term procurement are all positive developments for facilitating new generation investment in key areas of the grid.

1 Market Structure and Design Changes

1.1 Introduction/Background

This chapter reviews some of the major market design and infrastructure changes that impacted market performance in 2006. New market design elements in 2006 include an increase in the bid cap for energy and ancillary services from $250/MWh to $400/MWh. Additionally, in June 2006, the CPUC Resource Adequacy (RA) program went into effect along with similar type reliability showings for non-CPUC jurisdictional load-serving entities. The CAISO implemented these resource adequacy programs through its Interim Reliability Requirements Program (IRRP), which defines how RA resources are made available to the CAISO prior to the implementation of MRTU. In a related matter, in spring 2006, the CAISO filed a proposed Offer of Settlement with in a proceeding stemming from a 2005 complaint by the Independent Energy Producers (IEP) which alleged that the must-offer waiver process is unjust and unreasonable. The Offer of Settlement proposed tariff changes to establish a Reliability Capacity Services Tariff (RCST) under which any non-RA unit committed by the CAISO through the must-offer waiver process would be compensated. Although FERC approval of RCST provisions was not reached until February 2007, key provisions regarding the compensation of non-RA units committed by the CAISO through the must-offer process and allocation of these costs were ultimately approved with an effective date of June 1, 2006. All of these changes are discussed in greater detail below.

The infrastructure changes discussed below include changes in generation retirements and additions, various transmission upgrades implemented in 2006 and future projects. The chapter concludes with an overview of the implementation of market enforcement provisions relating to the CAISO Enforcement Protocols.

1.2 Market Design Changes

1.2.1 Increase in Bid Cap for Energy and Ancillary Services

On January 14, 2006, the bid cap governing transactions in the CAISO real-time balancing energy market was raised from $250/MWh to $400/MWh. The bid cap remained a “soft-cap,” meaning that participants could submit bids above $400/MWh but such bids are not eligible to set the market clearing price, and, if dispatched, would be paid as-bid and would be subject to cost justification with FERC. The Department of Market Monitoring (DMM) and the Market Surveillance Committee (MSC) spearheaded the effort to raise the bid cap due to concerns about rising natural gas prices stemming from the gulf coast hurricanes in the fall of 2005. DMM and the MSC expressed concern that if natural gas prices continued to escalate during the peak winter heating season, the marginal costs of some generation units could increase above the then current bid cap of $250/MWh. Though the energy bid cap is a “soft-cap,” both the DMM and MSC were concerned that suppliers, particularly importers, might elect not to offer into the CAISO Real Time Market rather than run the regulatory risk and burden of having their bids cost justified. DMM also pointed out a number of advantages a higher bid cap could produce, such as providing increased incentives for forward contracting and greater incentives for generator availability during peak demand periods.

The proposal to raise the bid cap was overwhelmingly supported by industry participants, and was approved by FERC on January 13, 2006 (January 13 Order) to be effective the following day. FERC maintained the bid cap as a "soft" cap.[1] The January 13 Order also instituted an investigation into the price cap in the WECC (outside the CAISO) and the bid cap for the CAISO Ancillary Services Market. After receiving comments, FERC issued an order on February 13, 2006 establishing a $400/MWh "soft" price cap in the WECC (outside the CAISO) and establishing a $400 "soft" bid cap for ancillary services bids in the CAISO market. The changes became effective upon issuance of the February 13 Order.

Though natural gas prices declined shortly after raising the bid cap, due to an unusually mild winter in the Eastern U.S. that reduced demand for gas, the $400/MWh "soft" bid cap for energy and ancillary services has remained in place. As a result of this increase, prices in both the CAISO Real Time Market and Ancillary Services Market have periodically approached or hit the new $400 cap. A more detailed discussion of the impact from the higher cap is provided throughout Chapters 2 through 4.

1.2.2 2006 Resource Adequacy Requirements

In 2006, Resource Adequacy (RA) programs developed by the CPUC and other Local Regulatory Authorities (LRAs) became effective. These programs, developed pursuant to Assembly Bill 380, require that load-serving entities (LSEs) procure sufficient resources to meet their peak load along with appropriate reserves. RA programs support system and local grid reliability by creating a framework intended to promote new generation investment in California by providing generation resources a revenue source to contribute towards fixed cost recovery. The CAISO facilitates implementation of these RA programs through its Interim Reliability Requirements Program (IRRP), which defines how RA resources are made available to the CAISO prior to the implementation of MRTU.

Beginning in June 2006, the CPUC directed its jurisdictional LSEs to procure sufficient resources to cover 100 percent of their forecast load for each month, plus a 15 percent margin for operating and planning reserves. The California Energy Commission determined a load forecast for each CPUC-jurisdictional LSE based on an allocation of each LSE's coincident share of the forecasted CAISO system peak for each month. Before applying the 15 percent reserve margin, each LSE's load forecast was adjusted downward based on its administratively determined share of demand response resources (i.e., load that can be curtailed) available in the utility service territory in which their load is located. LSEs not under CPUC jurisdiction, mainly local publicly-owned utilities, meet roughly similar requirements determined by their respective LRAs.

The CPUC and LRAs established various "counting rules" that established the types and quantities of resources that can be used to provide RA capacity in 2006. These included criteria for determining the amounts of capacity that could be provided by various types of resources. For CPUC-jurisdictional entities, the high-level criteria were as follows:

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[1] Federal Energy Regulatory Commission, "Order Accepting and Modifying Tariff Filing and Instituting a Section 206 Proceeding," issued January 13, 2006, 114 FERC ¶ 61,026.

- Generating units in the CAISO Control Area were counted based on their net qualifying capacity. This value was based on a generating unit's capacity reduced, as applicable, by testing results and deliverability restrictions. Although generating unit net qualifying capacity was not adjusted for outage rates, it is anticipated that performance criteria to adjust for outages will be developed by the CAISO in the future. The counting rules also specified criteria for determining the eligible capacity of wind and solar generation. In addition, the capacity provided by generating units under RMR Condition 2 contracts was allocated to those LSEs that paid the costs for these units.

- Imports were counted up to each LSE's allocation of import capacity on each inter-tie. These allocations were determined based on each LSE's existing resource commitments outside the CAISO Control Area as well as its proportional share of the forecasted peak load.

- Liquidated damages (LD) contracts, which are contracts to deliver energy that do not specify a generating unit as the source of the energy or inter-tie where an import will be delivered, were counted up to specified criteria. As the goal of the RA program is to make physical resources available to the system, the CPUC guidelines reduce the amount of LD contracts that can count as resource adequacy capacity over the next two years. For 2006, existing LD contracts could count towards as much as 75 percent of an LSE's capacity requirement. This value decreases 25 percent per year until LD contracts are precluded in 2009. The CPUC has adopted an exception to the LD contract prohibition for contracts executed by the California Department of Water Resources during the energy crisis – the total capacity under these contracts may be counted until they expire, which is generally over the next several years.

- Demand response resources were counted as a reduction to each LSE's forecasted load. As demand response programs are paid for through state-wide charges to end-use customers, demand response resources were allocated to LSEs in proportion to their share of the forecasted load.

In addition to the above, the CPUC counting rules included criteria to accommodate standard energy contracts. As standard energy contracts provide for capacity to be available for only specified hours (e.g., 5x8, 6x16), rather than for all hours of the month, the counting rules specified maximum capacity amounts in various categories defined by the hours available per month that could count as fulfilling an LSE's RA obligations.

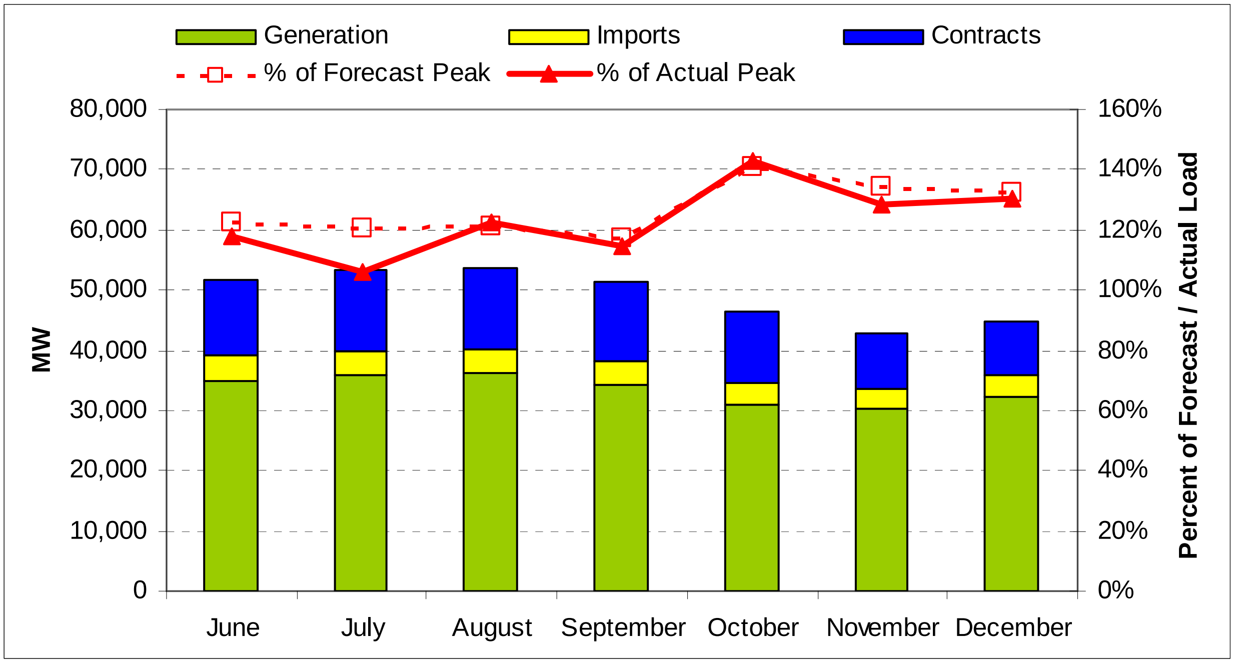
Figure 1.1 compares the RA resources available system-wide to the forecasted and actual system peak load for the months the RA program was in effect during 2006 – June through December.[2] Figure 1.1 also summarizes the mix of resources that were available system-wide, including generation, imports, and LD contracts. As shown in Figure 1.1, LSEs procured resources system-wide for each month in quantities that ranged from about 118 percent to 140 percent of the respective system monthly peak load forecast.[3] For July, the month in which the system peak load of 50,270 MW occurred, which was also a record peak, LSEs procured resources that amounted to about 121 percent of the forecast system peak and about 106

[2] Based on "1-in-2" load forecasts developed by the CEC and CAISO in April 2006, minus demand response resources. Resource quantities shown exclude demand response resources.

[3] The percentages shown in Figure 1.1 ("% of Forecast Peak" and "% of Actual Peak") are calculated by dividing the total capacity showing for each month by the forecasted or actual peak load for each month.

percent of the actual system peak. The quantities of resources procured for the other months ranged from about 115 to 143 percent of the respective actual monthly system peak load.

Figure 1.1 System-Wide RA Resources



The procurement requirements for 2006 were entirely on a system-wide basis. There was no requirement to procure resources based on capacity needs determined on a local load pocket or zonal basis. For 2007, LSEs under CPUC jurisdiction are required to obtain resources located within defined load pockets based on their share of the forecasted load within each CAISO Transmission Access Charge Area, which equate to the old service territories of the investor owned utilities. Both the system and local requirements are important to reliability, short-term revenue adequacy, and to provide a framework for investment in infrastructure. However, when viewing existing reliability issues in the CAISO Control Area, generation capacity at the local or regional level is of primary concern, and this is especially true in SP26. SP26 has higher loads than NP26, but less available generation. In addition, transfer capability between NP26 and SP26 is limited by the 4,000 MW north-to-south capacity of Path 26.[4]

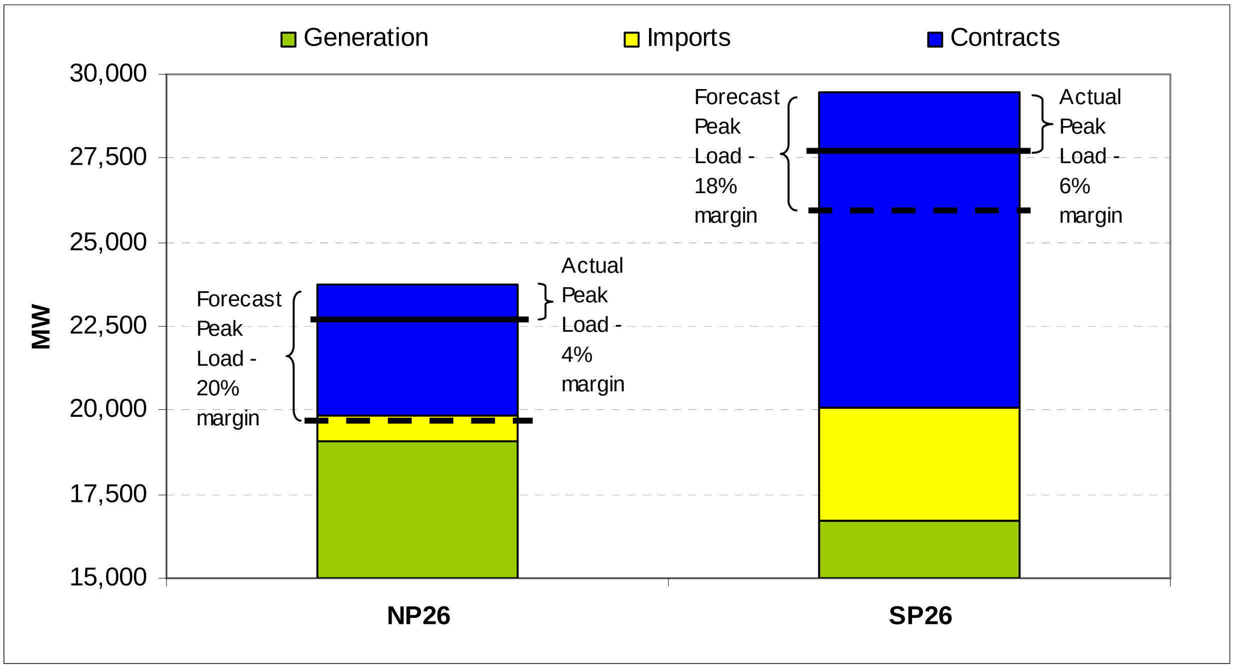
Figure 1.2 compares the RA resources for NP26 and SP26 that were procured for the peak load month of July 2006, to the respective NP26 and SP26 forecasted and actual peak loads. For the purpose of this analysis, generation resources were allocated to NP26 or SP26 based on their geographic location. LD contracts and imports were allocated based on their point of delivery.[5] As shown in Figure 1.2, LSEs procured RA resources with a total capacity of 23,757 MW in NP26 for July 2006, which provided a 20 percent margin over the July NP26 peak load forecast and a 4 percent margin over the NP26 actual peak load. As shown, the RA resources procured

[4] NP26 is defined as the NP15 and the ZP26 congestion zones, which are both north of Path 26. SP26 is defined as the SP15 congestion zone, which is south of Path 26.
[5] Approximately 1,000 MW of RA resources that were not designated as specific to NP26 or SP26 were pro-rated between NP26 and SP26.

in NP26 for July included 19,078 MW of generation, 758 MW of imports, and 3,884 MW of LD contracts.

For SP26, Figure 1.2 shows that LSEs procured RA resources with a total capacity of 29,473 MW for July 2006, which provided an 18 percent margin over the July SP26 peak load forecast and a 6 percent margin over the SP26 actual peak load. As Figure 1.2 shows, the mix of RA resources procured in SP26 consisted of significantly less generation and significantly more contracts and imports than that procured in NP26. In SP26, LSEs procured 16,712 MW of generation, 3,359 MW of imports, and 9,401 MW of LD contracts.

Figure 1.2 NP26 and SP26 RA Resources - July 2006



1.2.3 Changes to the Must-Offer Requirement

Under the terms of the IRRP taking effect in June 2006, all RA capacity that is available must be scheduled or made available to the CAISO for commitment through the CAISO's must-offer waiver denial process. Since RA units are eligible for capacity payments under bilateral contracts, IRRP tariff changes taking effect in June 2006 also specified that RA resources committed through the CAISO's must-offer process would be eligible to recover only minimum load operating costs from the CAISO and would no longer receive an additional payment for minimum load energy at the real-time energy price.

In recognition of the fact that RA and RMR resources may not be sufficient to meet all system reliability needs, CAISO continues to have the authority to commit other resources with Participating Generator Agreements with the CAISO through the must-offer waiver denial process. However, the IRRP specified that the CAISO could commit non-RA resources through the must-offer waiver process only if there are insufficient RA or RMR resources available to meet any local, zonal, or system reliability needs. Any non-RA resources committed through the must-offer process continue to receive payments for minimum load operating costs along with an additional payment for minimum load energy at the real-time energy price. These non-RA units are sometimes referred to as "FERC-MOO" units, due to the fact that their offer obligation stems from the Must-Offer Obligation (MOO) of the CAISO tariff approved by FERC, rather than through a bilateral RA contract or RMR contract with the CAISO.

In addition, starting in June 2006, any non-RA resources committed through the must-offer process also became eligible to receive additional payments under the terms of proposed tariff changes filed by the CAISO and other settling parties under an offer of settlement with various participants stemming from a 2005 complaint by generators that compensation under the must-offer waiver process is unjust and unreasonable. The dispatch on non-RA units under the must-offer process and these potential tariff changes are discussed below.

1.2.4 Reliability Capacity Services Tariff

In spring 2006, the CAISO, along with other settling parties, filed a proposed Offer of Settlement in a proceeding stemming from a 2005 complaint by the Independent Energy Producers (IEP), which alleged that the must-offer waiver process is unjust and unreasonable.[6] The Offer of Settlement proposed tariff changes to establish a Reliability Capacity Services Tariff (RCST) under which any non-RA unit committed by the CAISO through the must-offer waiver process for reliability needs would be compensated with a daily capacity payment. The RCST settlement also provided the CAISO with the authority to designate non-RA units to provide services under the RCST tariff as a "backstop" in the event that the CAISO determined that RA resources procured by LSEs did not meet projected reliability needs.

The proposed effective date for RCST was designed to be concurrent with terms of the IRRP, which was to take effect on June 1, 2006. All provisions of the RCST settlement were subject to FERC approval. Although FERC final approval of all RCST provisions was not granted until January 2007, key provisions regarding the compensation of non-RA units committed by the CAISO through the must-offer process and allocation of these costs were ultimately approved with an effective date of June 1, 2006.[7]

In approving the RCST settlement, FERC found that RCST provisions meet the reliability needs of the CAISO and ensure that generators providing reliability services will be appropriately compensated, thereby reducing the likelihood that units critical for reliability will be mothballed or shut down. Key provisions of the RCST include the following:

- **RCST Capacity Payments.** In addition to receiving minimum load costs, non-RA units designated as RCST are eligible to receive an RCST capacity payment. The capacity payments are equal to $73/kW-year, less a variable Peak Energy Rent (PER) amount that is calculated each month based on the potential net energy and ancillary services revenues that could be earned by a new peaking unit given actual CAISO market prices. The net payment was designed to reflect a reasonable price for "backstop" capacity and encourage LSEs and generators to engage in longer term contracting and not rely on the must-offer mechanism. This net RCST capacity payment is calculated on a monthly

[6] In addition to IEP and the CAISO, other settling parties were the California Public Utilities Commission and the state's three major utilities: SCE, PG&E and SDG&E. The proposed settlement can be found on the CAISO website at http://www.caiso.com/17ca/17cad5ec10650.pdf.

[7] See FERC's January 22, 2007 Order on Rehearing, Clarification and Compliance Filing, ER06-723-001, et al . http://www.caiso.com/1b70/1b70e88c20010.pdf.

basis by allocating these annual fixed costs to each month using monthly percentages, which allocate a higher portion of annual fixed costs to summer months relative to other months of the year.

- **RCST Designations.** Any non-RA units designated as RCST units by the CAISO for one or more months are eligible for the monthly capacity payment described above. The RCST settlement also provides that if any non-RA unit is committed under the must-offer waiver process for four separate days in any year, the CAISO would evaluate whether a significant change in grid operations had occurred that warrants making additional RCST designations.

- **Daily RCST Capacity Payments**. Any non-RA units committed through the CAISO's must-offer process are eligible for a daily RCST capacity payment equal to 1/17th of the monthly capacity payment described above. However, daily RCST capacity payments for any month may not exceed the total monthly capacity payment described above. As discussed below, about $10.6 million in daily RCST capacity payments under this provision occurred in 2006 due to non-RA units being committed through the must-offer waiver process, with over three-quarters of these costs occurring during periods of extremely high system loads in June through August.

- **Real Time Energy Mitigation Adder.** The RCST tariff provisions also include a potential $40/MWh payment adder for certain units that are mitigated under the CAISO's current local market power mitigation (LMPM) measures more than four 10-minute intervals in one day.[8]

Figure 1.3 shows the total amount of non-RA capacity committed by the CAISO through the must-offer waiver process on a daily basis since the effective date of new RA and RCST provisions in June 2006. Committed capacity is summarized for the following three categories:

- **System.** This category includes units committed to ensure that on a system-wide level sufficient capacity is available to meet all interruptible and firm load based on day-ahead forecasts and expected imports.[9]

- **Zonal**. This includes capacity committed to ensure that sufficient resources are online or available in Southern California (south of Path 26) to meet the East-of-River/Southern California Import Transmission (SCIT) nomogram and/or to meet the WECC MORC requirements for managing pre- and post-contingency loading criteria on transmission serving the region south of Path 26.

[8] Under current LMPM measures, bids dispatched out-of-sequence for intra-zonal congestion or local reliability needs which are in excess of $50 or 200 percent of the interval MCP are mitigated to their reference price and settled on the greater of the mitigated bid or the interval MCP. Under the RCST tariff provisions, bids mitigated under these LMP provisions may have up to $40/MWh added to their mitigated price if the unit is subject to LMPM more than four 10-minute intervals in one day. However, the $40/MWh adder is reduced if necessary so that the total price paid under LMPM does not exceed the original bid price.

[9] See Procedure M-432. http://www.caiso.com/docs/2004/09/03/2004090313342914798.pdf.

- **Local.** This includes capacity committed to local environmental and reliability constraints. Environmental constraints include restrictions established by state or federal agencies that limit or require generation to be operated in a particular way for environmental quality reasons. Local reliability requirements include capacity needed to meet temporary operational requirements to support planned transmission maintenance work.

As shown in Figure 1.3, since the IRRP took effect in June 2006, virtually all of the non-RA capacity committed under the must-offer waiver process was due to system and zonal requirements. More specifically:

- Over half (54 percent) of the total non-RA capacity committed under the must-offer waiver process was committed due to system level requirements. Virtually all of these commitments occurred during late June and late July, when total system loads significantly exceeded the 1-in-2 year load forecast upon which RA requirements are based.

- About one-third (35 percent) of the non-RA capacity committed under the must-offer waiver process were due to zonal reliability requirements in Southern California. Again, virtually all of these commitments occurred during late June and late July, when total system loads significantly exceeded the 1-in-2 year load forecast upon which RA requirements are based.

- Only about 11 percent of the non-RA requirements were for local reasons. About half of these commitments were due to environmental regulations in the Bay Area.

Table 1.1 provides a summary of day-ahead waiver denial activity for non-RA resources in 2006, which is based on preliminary reports published by the CAISO on a monthly basis pursuant to the RCST Settlement, combined with updated estimates of daily RCST capacity payments developed as part of the settlement process.[10] Figure 1.4 summarizes estimated total minimum load costs and daily RCST capacity payments for non-RA units since the effective date of new RA and RCST provisions in June 2006.

As shown in Table 1.1 and Figure 1.4, minimum load costs associated with must-offer waiver denials for non-RA units from June through December totaled just over $20 million, while potential daily RCST capacity payments totaled about $10.6 million. Zonal requirements involving zonal reliability needs in Southern California accounted for about 50 percent of these minimum load costs and about 75 percent of daily RCST capacity payments. About 37 percent of these minimum load costs and 10 percent of daily RCST capacity payments are associated with system level requirements. Local environmental and reliability needs accounted for about 13 percent of these minimum load costs and 15 percent of daily RCST capacity payments.

The relatively low portion of daily RCST capacity payments associated with must-offer waiver denials for system needs reflects the fact that during the months of June and July – when

[10] Non-RA units may also receive a payment adder of up to $40/MWh for out-of-sequence dispatches mitigated under LMPM provisions. However, initial analysis indicates that these additional payments would total only about $23,000 for 2006.

virtually all of these commitments occurred – the daily RCST capacity payments were very low due to the fact that high market prices caused the Peak Energy Rent (PER) calculation to offset all or most of the potential capacity payment. As shown in Figure 1.5 , the PER in Northern California exceeded the monthly cost of installed capacity during June and July, resulting in a zero net RCST payment for this area. Similarly, the PER for Southern California offset about 87 percent of the monthly installed capacity cost during June and July (Figure 1.6). The daily RCST payment for non-RA units committed for system reliability are based on the region in which the resource is located.

Figure 1.3 Non-RA Capacity Committed Under Must-Offer Waiver Process Eligible for RCST

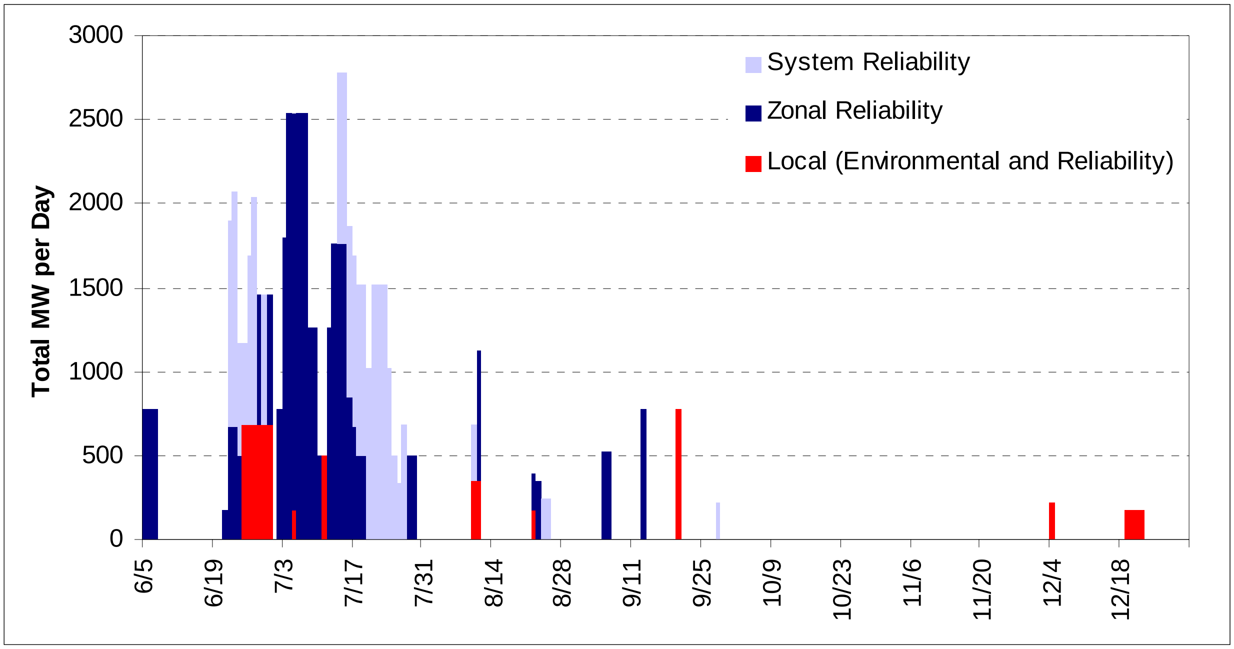
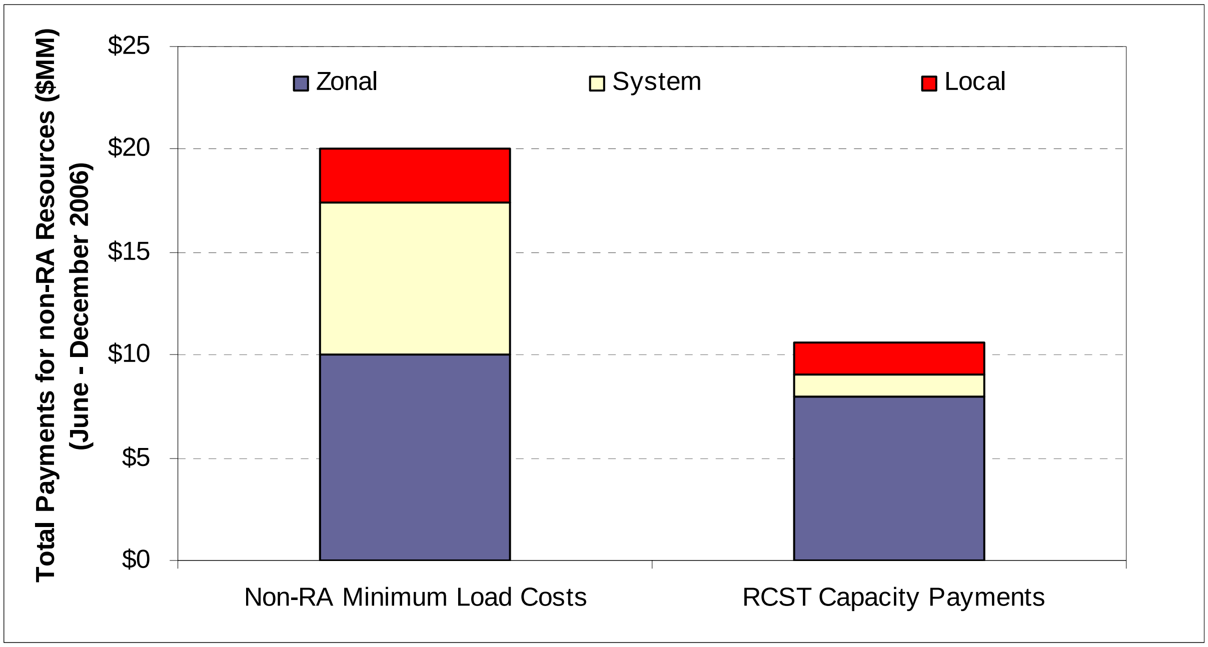


Table 1.1 Non-RA Waver Denials (June – December 2006)[11]

TAC/Service Area	Description	Local	Zonal	System	Total
Northern (PG&E)	FERC-MOO Waiver Denials (Unit-Days)	6	0	32	38
	Estimated Minimum Load Costs	$2,024,621	$0	$5,020,298	$7,044,919
	Estimated FERC-MOO Capacity Costs[12]	$0	$229,711	$0	$229,711
East Central (SCE)	FERC-MOO Waiver Denials (Unit-Days)	13	81	26	120
	Estimated Minimum Load Costs	$659,825	$10,051,071	$2,324,530	$13,035,427
	Estimated FERC-MOO Capacity Costs[12]	$1,600,070	$830,198	$7,941,019	$10,371,286
Southern (SDG&E)	FERC-MOO Waiver Denials (Unit-Days)	0	0	0	0
	Estimated Minimum Load Costs	$0	$0	$0	$0
	Estimated FERC-MOO Capacity Costs[12]	$0	$0	$0	$0
Total	FERC-MOO Waiver Denials (Unit-Days)	19	81	58	158
	Estimated Minimum Load Costs	$2,684,446	$10,051,071	$7,344,828	$20,080,345
	Estimated FERC-MOO Capacity Costs[12]	$1,600,070	$1,059,915	$7,941,019	$10,600,997

Figure 1.4 Total Payments for Non-RA Resources (June – December, 2006)



[11] Source: Total of preliminary monthly reports posted on CAISO website (see http://www.caiso.com/17c6/17c6a16019910.html). Estimated costs for FERC-MOO Capacity Costs based on updated calculations developed as part of settlement process.

[12] Based on 1/17th of the annual capacity payment ($73/kw-yr) and applying a monthly shaping factor specified in the RCST Offer of Settlement. For the purposes of this analysis capacity costs are limited when total daily capacity costs plus imbalance costs for minimum load energy (frequently mitigated adder costs not considered in this analysis) for the month exceeds the maximum monthly RCST payment reduced by PER (Table 1.1).

Figure 1.5 Maximum Potential Monthly RCST Capacity Payments in Northern California (PG&E Transmission Service Area)

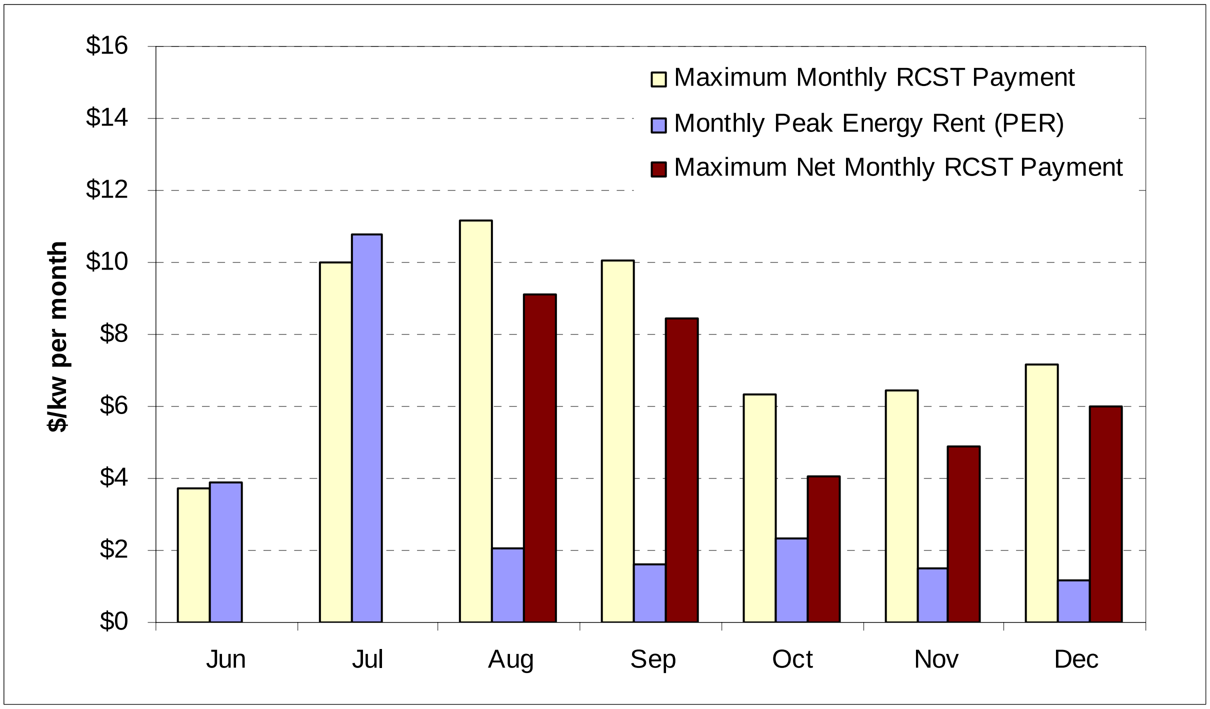
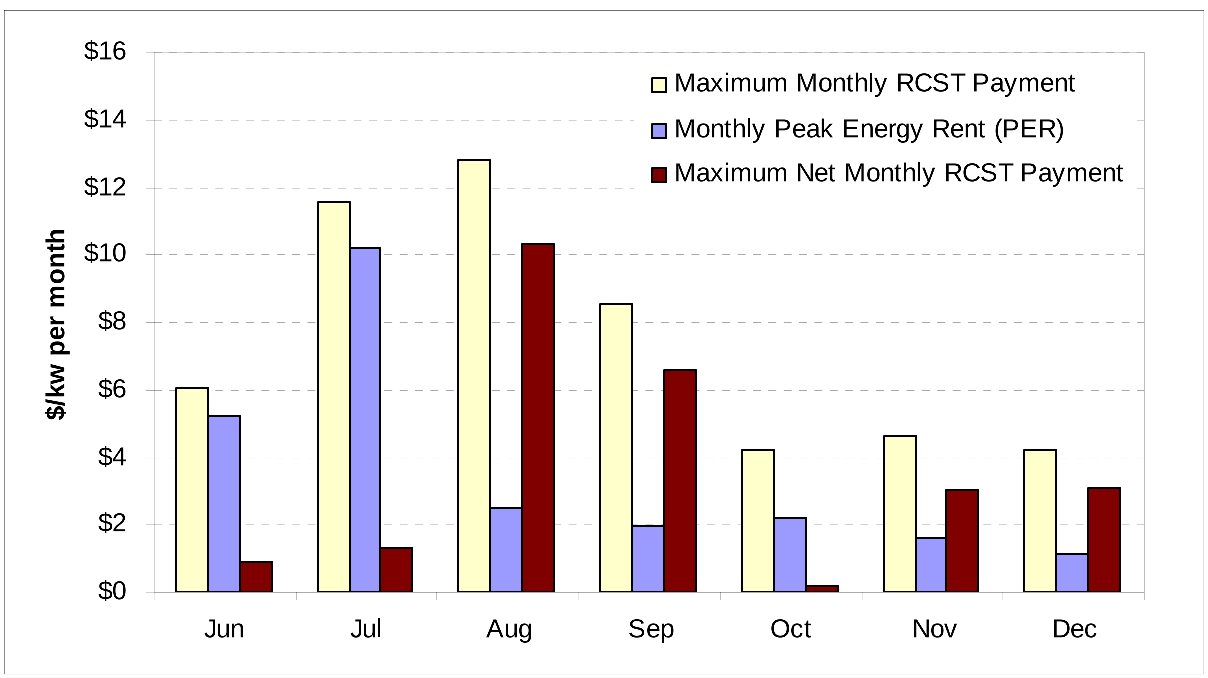


Figure 1.6 Maximum Potential Monthly RCST Capacity Payments in Southern California (SCE and SDG&E Transmission Service Areas)



With respect to the CAISO issuing waiver denials for "zonal" reasons, some market participants have argued that this capacity should be procured through the CAISO Ancillary Services Market by procuring operating reserves on a zonal basis in sufficient amounts to meet some pre-specified level of zonal reserve requirements. They further argue that the current non-market practice of meeting zonal reliability requirements through waiver denials fails to reflect the true value of the zonal capacity, and consequently fails to fairly compensate generator owners that provide this reserve capacity or provide appropriate market price signals for new generation development.

In regard to these concerns, it is important to note that the zonal reliability requirements are typically driven primarily by the need to restore power flows to path ratings after a major contingency within 20 minutes for a stability-limited path or 30-minutes for a thermally limited path. However, the current CAISO Ancillary Services Market products are 10-minute operating reserves (Spinning and Non-Spinning Reserve) and Regulation. There is currently no 20-minute or 30-minute reserve product for the CAISO to procure from the Ancillary Services Market to meet these reliability requirements. Therefore, the CAISO currently meets these zonal reliability requirements through a combination of 10-minute operating reserve, and slower-moving on-line capacity and quick start-capacity subject to a must-offer requirement in the CAISO's Real Time Market. It would not be appropriate or efficient to simply procure enough 10-minute operating reserve to meet these 20- to 30-minute zonal reserve requirements since such an approach would significantly exceed the actual reliability requirement and impose excessive ancillary service costs on LSEs. In addition, such an approach would likely lead to market power problems given the magnitude of the 20- to 30-minute reliability requirements and the limited competition at the zonal level to provide 10-minute operating reserves equal to these requirements.

If the CAISO were to design a market for 20- to 30-minute ancillary service reserve products, it may be appropriate to attempt to meet zonal reliability requirements primarily through the Ancillary Services Market.[13] However, such procurement would need to be closely monitored for market power issues to determine whether additional market power mitigation provisions are required. The CAISO is not currently planning to implement a 20- or 30-minute reserve product for either 2007 or under the initial release of MRTU in 2008. However, this issue should be given serious consideration for future MRTU releases. In the meantime, the locational value of 20- to 30-minute generating capacity will need to be captured in the current RA procurement practices and through the backstop RCST payment mechanism, which, as discussed above, provides for daily capacity payments to non-RA resources that are denied must-offer waivers. It should also be noted that, while the current CPUC RA provisions do not fully address zonal capacity requirements, the CAISO is pursuing zonal capacity requirements as part of the pending Phase 2 CPUC RA proceeding.

1.2.5 CPUC Long Term Procurement Rules

In addition to addressing short-term capacity requirements through the Resource Adequacy program, the CPUC has also required that load-serving entities under its jurisdiction develop and file 10-year long-term procurement plans (LTPPs) designed to comply with any and all

[13] An additional problem with seeking to rely only on a market to meet all reliability requirements, including stability and thermal limitations after an N-1 contingency, is the highly dynamic nature of these reliability requirements. In practice, these reliability requirements may not be determined on a day-ahead basis. However, MRTU market rules require that the CAISO seek to meet all Ancillary Service requirements in the Day Ahead Market.

policy constraints and to adequately meet bundled customer load needs. The 2006 LTPPs will need to reflect all procurement related decisions from prior CPUC rule-makings, including the following:

- Adopted Demand Response programs and attainment goals.
- Procurement “loading order” as reflected in the state agencies’ Energy Action Plan II and adopted by the CPUC.
- Identify the key planning decisions required to meet a renewable portfolio standard of 33 percent by 2020.

On December 11, 2006, CPUC jurisdictional entities submitted their long-term procurement plans to the CPUC. Intervener testimony was submitted on March 2, 2007 and reply testimony is due on April 9, 2007. The CAISO has been reviewing the LTPPs to determine whether the proposals raise any operational issues that parties should be aware of. The CPUC is expected to approve the LTPPs later in 2007.

Additionally, in a July 21, 2006 decision, the CPUC directed Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) to procure 1,500 MW and 2,200 MW of new generation, respectively, and to unbundle the capacity and energy products from this new generation. It was determined that PG&E needed 1,200 MW of new peaking generation and 1,000 MW of new peaking and dispatchable generation by 2010 and that SCE would have the option of a two track approach with a “fast-track” RFO for new generation coming on-line beginning mid-2009 and a “standard track” with expected on-line dates of 2012-2013. However, if SCE does not pursue all 1,500 MW under a fast track, it must justify to the CPUC why it is appropriate to pursue some of the generation under the standard track. Under this decision, the capacity of the new generation would be allocated to each load-serving entity in the IOU’s service territory and count towards its RA requirements. The costs of the capacity would be allocated similarly. The energy product will be auctioned off by a third party. The CPUC action was taken due to the urgency for new generation investment in California and the recognition that a more permanent long-term procurement structure, that effectively addresses the need for long-term procurement and retail competition, would not be completed for some time.

1.3 Generation Additions and Retirements

1.3.1 Generation Additions and Retirements in 2006

Approximately 633 MW of new generation began commercial operation within the CAISO Control Area in 2006. The majority of new capacity in the North was wind generation (150 MW out of 199 MW total in the North). Table 1.2 shows the new generation projects that began commercial operation in 2006.[14]

[14] Note that the Palomar and Mountain View facilities, totaling 1,066 MW of new generation, were included in the 2005 generation additions in the 2005 Annual Report on Market Issues and Performance.

Table 1.2 New Generation Facilities Entering Commercial Operation in 2006

Generating Unit	Net Dependable Capacity (MW)	Commercial Operation Date	Zone ID
Buena Vista	37.6	29-Dec-06	NP26
Central Disposal Site LFG Power Plant	8.0	09-Jan-06	NP26
Santa Cruz Landfill Generating Plant	3.6	02-Feb-06	NP26
Shiloh 1 Wind Project	150.0	30-Mar-06	NP26
NP26 New Generation in 2006	***199.2***		
Kern River Units 1, 2, 3 & 4	340.0	01-Jun-06	SP26
MM Lopez Energy, LLC	6.0	28-Aug-06	SP26
MMC Chula Vista	44.0	08-Jun-06	SP26
MMC Escondido	44.0	07-Jun-06	SP26
SP26 New Generation in 2006	***434.0***		
Total New Generation in 2006	**633.2**		

Source: California ISO Grid Planning Department

Approximately 1,535 MW of generation capacity was removed from service in 2006, the majority of which was located in the SP26 congestion zone. The most notable of the retirements is the Mohave units, which were the last remaining coal-powered resources in the CAISO Control Area[15].

Table 1.3 Retired Generation Facilities in 2006

Generating Unit	Net Dependable Capacity (MW)	Zone ID
Hunters Point Units 1 & 4	215	NP26
NP26 Retired Generation in 2006	***215***	
Mohave Units 1 & 2	1,320	SP26
SP26 Retired Generation in 2006	***1,320***	
Total Retired Generation in 2006	**1,535**	

Capacity retirements considerably outpaced additions in 2006, leading to a net reduction in capacity in the CAISO control area of 902 MW as seen in Table 1.4.

[15] Though the Mohave coal-fired generating units are physically located outside of California (Southern Nevada), they were incorporated into the CAISO Control Area, which is why they are included in Table 1.3.

Table 1.4 Generation Change in 2006

Region	Generation Additions (MW)	Generation Reductions (MW)	Net Change in Generation (MW)
NP26	199	-215	-16
SP26	434	-1,320	-886
CAISO Control Area	**633**	**-1,535**	**-902**

1.3.2 Anticipated New and Retired Generation in 2007

The CAISO projects construction of 1,484 MW of new generation in 2007, of which roughly 650 MW are expected to be commercially available prior to the anticipated summer peak season. There are two 405 MW resources, the Inland Empire units shown in Table 1.5 below, that will be parallel in 2007 but are not anticipated to complete testing and begin commercial operation until 2008.

Table 1.5 Planned Generation Facilities in 2007

Generating Unit	Resource Owner / QF ID	Resource Capacity (MW)	Expected Parallel Date	Zone ID
Bottle Rock Power	Bottle Rock Power	55.0	04-Apr-07	NP26
Keller Canyon Landfill Generating Facility	Ameresco Renewables	3.8	16-Jul-07	NP26
Lake Mendocino Hydro	City of Ukiah	3.5	21-Mar-07	NP26
Marina-LFG2	Monterey Regional Waste Mgmt Dist.	2.6	01-Apr-07	NP26
MM Yolo Power LLC	Minnesota Methane	3.6	01-Jan-07	NP26
MMC Mid-sun, LLC Repower	MMC Energy	22.0	16-Jan-07	NP26
Ox Mountain Landfill Gas Generation	Ameresco Renewables	11.4	15-Aug-07	NP26
Santa Clara Wind Project	AES Seawest	24.1	23-Feb-07	NP26
Santa Maria Cogen	Wellhead Power	10.2	23-Jan-07	NP26
NP26 Planned New Generation in 2007		***136.2***		
Barre Peaker	SCE	49.0	18-Aug-07	SP26
Center Peaker	SCE	49.0	31-Jul-07	SP26
Chiquita Canyon Landfill	Ameresco Renewables	9.2	15-Nov-07	SP26
Grapeland Peaker	SCE	49.0	31-Jul-07	SP26
Inland Empire Energy Center Unit 1 & 2	GE	810.0	10/1/2007	SP26
Long Beach Unit 1	NRG	65.0	01-Jun-07	SP26
Long Beach Unit 2	NRG	65.0	01-Jun-07	SP26
Long Beach Unit 3	NRG	65.0	01-Jun-07	SP26
Long Beach Unit 4	NRG	65.0	01-Jun-07	SP26
McGrath Beach Peaker	SCE	49.0	30-Aug-07	SP26
Mira Loma Peaker	SCE	49.0	21-Aug-07	SP26
MM Tajiguas Energy, LLC	Algonquin Power	3.1	01-Apr-07	SP26
MM Tulare Energy, LLC	Minnesota Methane	1.6	01-Jan-07	SP26
Otay 3	Covanta Energy	3.8	14-Mar-07	SP26
Rancho Penasquitos Hydro Facility	San Diego County Water Authority	4.7	23-Jan-07	SP26
San Dimas Wash Hydro	San Gabriel Valley Muni. Water Dist.	1.1	01-Apr-07	SP26
West Covina 1	Minnesota Methane	3.3	01-Jan-07	SP26
West Covina 2	Minnesota Methane	6.5	01-Jan-07	SP26
SP26 Planned New Generation in 2007		***1,348.2***		
Total Planned New Generation in 2007		**1,484.4**		

Currently there are no planned generation retirements in 2007; however, unlike the lengthy process for constructing a new resource and bringing it online, a generation owner can retire an existing resource 90 days after notifying the CAISO.

Table 1.6 below shows an annual accounting of generation additions and retirements since 2001, with projected 2007 changes included along with totals across the seven year period (2001-2007).

Table 1.6 Changes in Generation Capacity Since 2001

	2001	2002	2003	2004	2005	2006	Projected 2007	Total Through 2007
SP15								
New Generation	639	478	2,247	745	2,376	434	1,348	8,267
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	(4,280)
Forecasted Load Growth*	148	500	510	521	531	542	553	3,305
Net Change	**491**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**795**	**682**
NP26								
New Generation	1,328	2,400	2,583	3	919	199	136	7,568
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	2,895
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(303)**	**3,438**
ISO System								
New Generation	1,967	2,878	4,830	748	3,295	633	1,484	15,835
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	(5,515)
Forecasted Load Growth*	537	897	915	934	953	972	991	6,199
Net Change	**1,402**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**493**	**4,121**

* Forecasted load growth is based a 2 percent peak load growth rate applied each year.

As shown in Table 1.6, there was a 902 MW net decline in installed generation in the CAISO Control Area in 2006 (633 MW new generation less 1,535 MW of unit retirements), the first net decline in installed generation in the post energy crisis period. The total net increase in installed generation in the CAISO Control Area over the seven years spanning 2001-2007 is roughly 10,000 MW and the net additions across the 2006-2007 period leaves the CAISO Control Area only a few hundred MW above the installed generation level of 2005. When adjusted for annual load growth, the net increase in installed generation drops from 10,000 MW to just over 4,100 MW over the past seven years.

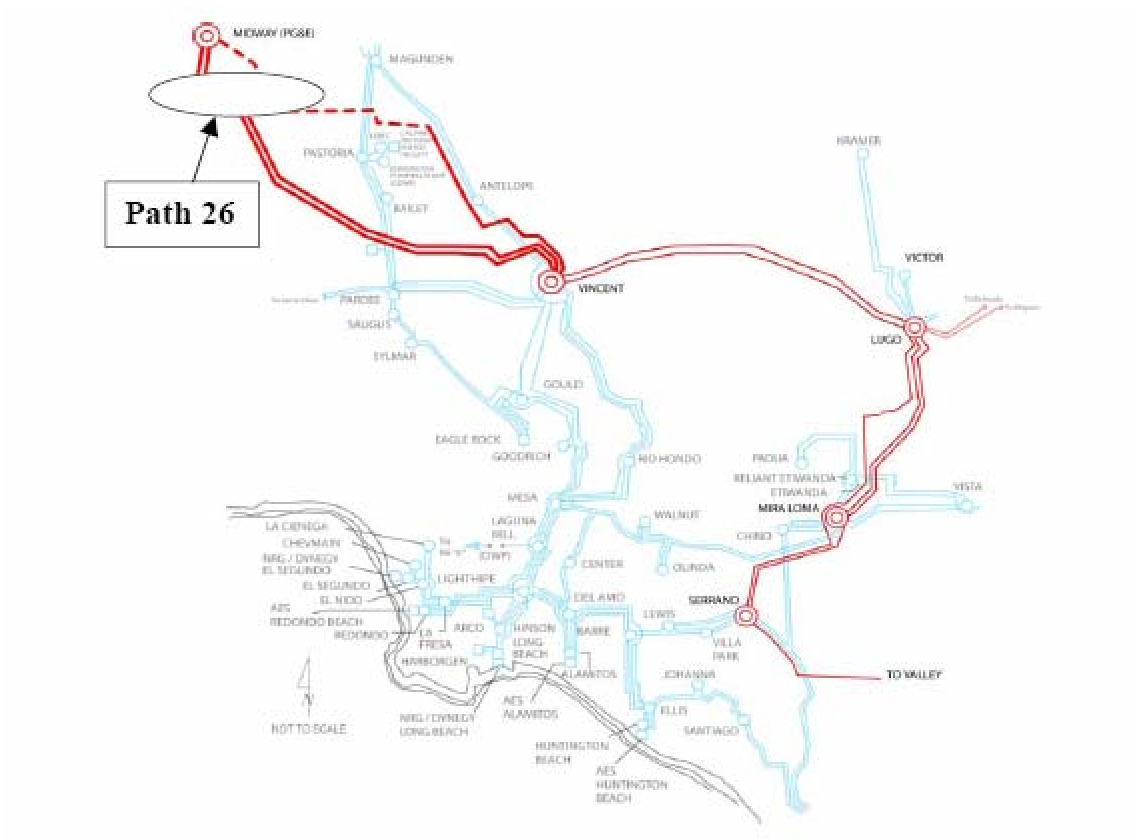
1.4 Transmission System Enhancements

1.4.1 Path 26 Remedial Action Scheme Enhancement

Path 26 consists of three 500kV lines between the Midway and Vincent substations and is a major interface and constraint for power flows between Northern and Southern California (see Figure 1.7). Path 26 originally had a bi-directional rating of 3,000 MW and had experienced substantial amounts of north-to-south congestion over the last several years. To mitigate this congestion issue, the Path 26 owners (PG&E and SCE) and the CAISO completed a WECC Rating Process to increase the WECC Accepted Rating in the north-to-south direction from 3,000 MW to 3,700 MW. This increase went into effect in June 2005. In addition, in order to mitigate anticipated congestion on Path 26 during the summer of 2005, the Path 26 owners and the CAISO requested an interim operational transfer capability (OTC) for Path 26 of 4,000 MW for the summer 2005 operating period (July – September 2005). The interim Path 26 OTC rating was granted by WECC and expired at the end of summer 2005. Path 26 operated at its WECC Accepted Rating of 3,700 MW since September 2005 through May 31, 2006.

On April 22, 2005, the CAISO submitted a report to WECC recommending a permanent increase to the north-to-south rating on Path 26 to 4,000 MW beginning in summer 2006. The new north-to-south Path 26 rating was approved by WECC on June 1, 2006.

Figure 1.7 Path 26 Midway-Vincent



1.4.2 New Jefferson-Martin Line

The Jefferson-Martin transmission project was designed to address both reliability needs within the San Francisco Peninsula area as well as environmental issues with regard to facilitating the retirement of an older generating facility located on the peninsula (Hunters Point Power Plant). The project involved installing a new 28-mile 230kV transmission line, with both overhead and underground segments, along the San Francisco Peninsula between the Jefferson and Martin substations and installing a second 230/115kV transformer at the Martin substation. The project was completed on April 29, 2006 and resulted in an additional 350 MW of transfer capability along the San Francisco Peninsula.

1.4.3 East/West of the River Upgrades

The WECC transfer ratings for the major transmission interfaces between California and the Desert Southwest, East-of-the-River (EOR) and West-of-the-River (WOR), were increased by 505 MW in 2006 to 8,055 MW and 10,623 MW, respectively. The EOR increase took effect on July 1, 2006 and the WOR increase took effect on November 8, 2006. The specific upgrades that resulted in this increase were the following:

(a) Series capacitor upgrades on the Palo Verde to Devers and Hassayampa to North Gila 500kV lines. In addition, the North Gila to Imperial Valley 500kV lines were upgraded with higher ampere ratings.

(b) A second 500/230kV transformer bank was added at the Devers Substation (SCE).

(c) 600 MVAR of dynamic voltage support was added at the Devers 500kV Bus, which was comprised of 150 MVAR of Mechanically Switched Capacitors (MSC) and 450 MVARs of Static Var Compensators (SVC).

(d) Special Protection Scheme added to mitigate for the contingency overload on the 230/161kV transformer from Imperial - Valley (SDG&E) to El Centro (IID).

The increased WECC transfer ratings resulted in a 505 MW increase on the Palo Verde Branch Group (from 2,823 MW to 3,328 MW). The increase was implemented on a conditional basis in July 2006 and was fully adopted on November 8, 2006, after the WOR increase took effect.

1.5 Administration of the Enforcement Protocol

1.5.1 Enforcement Protocols

As part of the CAISO organizational realignment in 2005, the Department of Market Monitoring (DMM) was assigned the responsibility of administering the Enforcement Protocol (EP) of the CAISO tariff. The EP was developed over a two year period from 2002 through 2004 through an effort led by the CAISO Compliance and Legal Departments. The EP is designed to provide clear Rules of Conduct specifying the behavior expected of Market Participants, and establish in advance the sanctions and other potential consequences for violations of the specified Rules of Conduct. In December 2005, FERC granted the CAISO authority to enforce penalties only for objectively identifiable violations of the CAISO tariff for which specific penalties are established in the EP. In enforcing these penalties, CAISO is not authorized to waive or modify penalties for mitigating circumstances, and may only recommend that FERC waive or modify penalties through a formal filing with the Commission. FERC rules require that all other potential violations of the CAISO tariff or FERC market rules be referred to FERC's Office of Enforcement (OE) for potential investigation and sanction.

In spring 2006, DMM initiated programs to enforce the two major objectively identifiable violations of the CAISO tariff for which specific penalties are established in the EP.

- ***Load Forecasting Requirements*.** Amendment 72 requires all Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95 percent of their forecasted demand for each hour of the next day. The CAISO did not seek to include a penalty for failing to meet the 95 percent scheduling requirement in Amendment 72. Instead, the CAISO's Amendment 72 filing indicated that any failure to meet this requirement may be subject to enforcement by FERC under FERC market rules, which include a general requirement that participants comply with all provisions of the CAISO tariff. However, Amendment 72 explicitly provided that failure to submit day-ahead forecast and weekly reports would be subject to sanction under the EP, which provides for a penalty of $500 for failure to submit required information. Compliance with these forecasting and reporting requirements has been virtually 100 percent since May 2006, compared to only about 75 percent in the first five months of 2006, as shown in Figure 1.8.

- ***Generation Outage Reporting*.** Due to the importance of timely and accurate outage reporting for grid reliability, the EP established significant penalties for failure to comply with the generation outage reporting requirements specified in the CAISO tariff, including penalties of up to $5,000 per outage that is not reported within 30 minutes. In advance of summer 2006, DMM implemented a program to routinely enforce these generation outage reporting requirements. However, as a result of market participant concerns about the stringency of the CAISO's existing outage reporting requirements – and DMM's lack of discretion in enforcing these requirements – DMM recommended that the CAISO submit a filing to FERC to temporarily suspend the associated penalties. In July 2006, the CAISO requested that FERC temporarily suspend the CAISO's existing outage-reporting penalties so that the CAISO could initiate a stakeholder process to modify existing reporting requirements and address stakeholder concerns. While the CAISO developed modifications to the outage reporting requirements and reporting tools scheduled for implementation in 2007, DMM continued to monitor outage reporting compliance. As shown in Figure 1.9, this monitoring indicated that outage reporting compliance has remained relatively the same over the two year period from 2005 to 2006, with an average of about 75 percent of outages reported within 30 minutes before and after DMM began notifying participants of the intent to begin enforcing this reporting requirement in April 2006. The CAISO's Outage Management Department has indicated that this level of compliance is acceptable from the standpoint of system reliability, but has reaffirmed its desire to require all outages be reported within 30 minutes. The number of outages reported did increase after DMM began notifying participants of the intent to begin enforcing this reporting requirement in April 2006, but it cannot be determined whether this increase in reporting frequency is due to increased awareness of the requirement or other factors, such as the unusually high loads experienced in summer 2006. Enforcement of the penalty provisions for late outage reporting is expected to be implemented in June 2007 once the reporting tool enhancements are put into place and market participants gain sufficient experience with these new tools.

Figure 1.8 Potential Non-Compliance with Load Forecast Submission Requirements

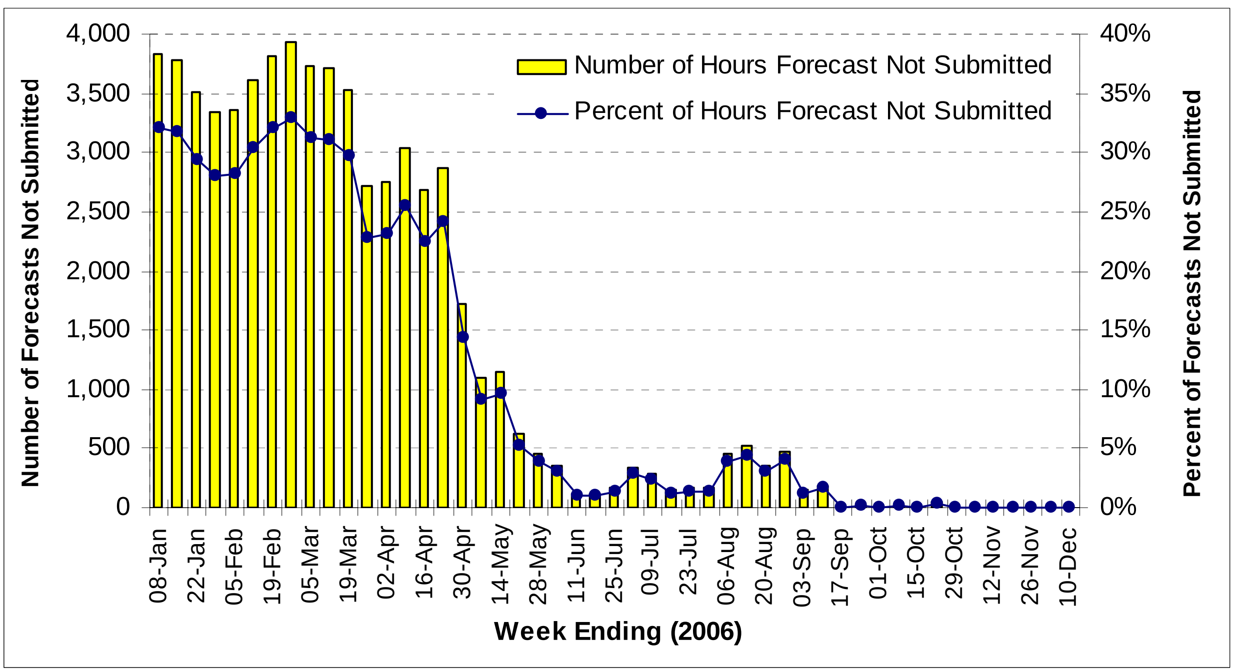
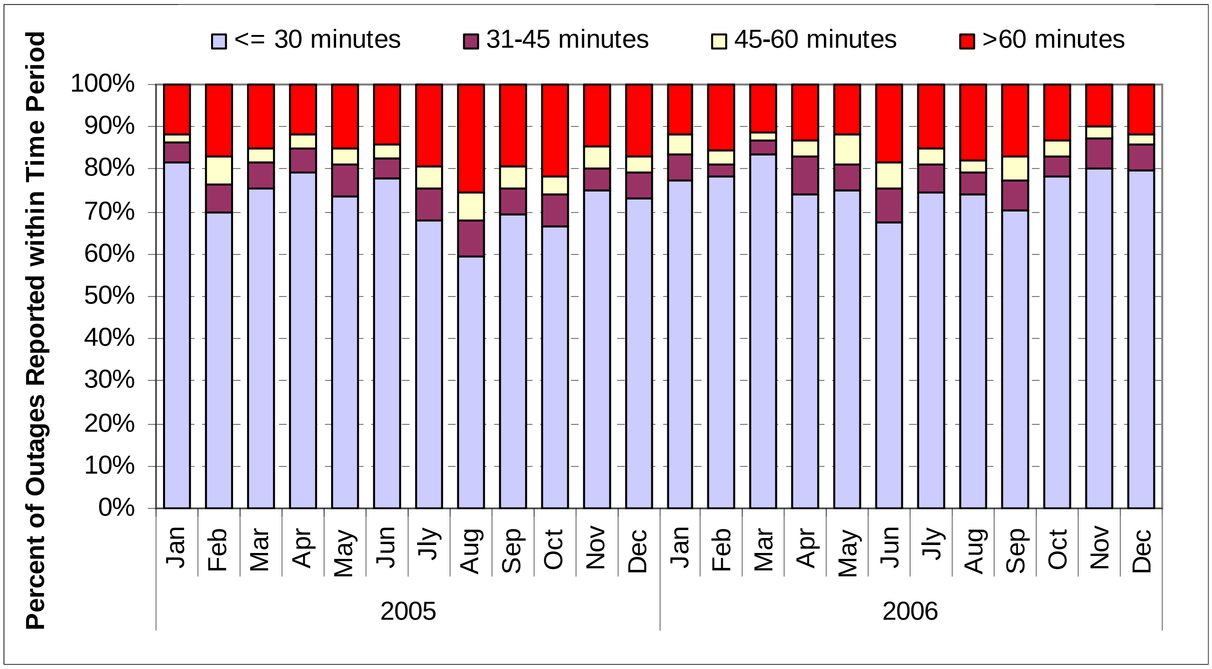


Figure 1.9 Potential Non-Compliance with 30-Minute Generation Outage Reporting Requirement



2 Summary of Energy Market Performance

2.1 Demand Conditions

Energy demand in 2006 was highlighted by a record breaking heat wave between July 5 and July 28 that crested between Monday, July 17 and Monday, July 26. During this week, California experienced record heat across nearly the entire state, but particularly in Northern California, where temperatures peaked at 112 degrees in Sacramento on Saturday, July 22. The Northern California peak on Monday, July 24, of approximately 22,650 MW was judged to have been approximately a 1-in-50 probability peak, and was a level that had not been anticipated to have been seen until early in the next decade. Meanwhile, the Southern California peak that day of 26,459 MW was judged to have been approximately a 1-in-10 probability peak.

After that extraordinary heat wave subsided around July 28, the summer was relatively moderate, and loads were manageable into the fall. This was also the case earlier in 2006 throughout the winter and spring. Table 2.1 shows two sets of annual load statistics for the CAISO Control Area; namely, statistics based on actual loads, and statistics based on adjusted loads that reflect changes to the CAISO Control Area footprint, and adjustments for days of the week and the 2004 leap year.

Also contributing to the annual load growth rate was a warm June 2006, whereas June 2005 was relatively cool. As shown in Table 2.2, load increased 12.3 percent on average between June 2005 and June 2006. In the second half of June 2006, approximately 9 days had peak loads above 40,000 MW. There was not one such day in June 2005; in fact, there were some midweek days in early June 2005 with daily peaks below 30,000 MW.[1]

[1] As June often features strong hydroelectric production due to the runoff from melting snow in the Sierra and the Pacific Northwest, in addition to mild weather throughout the West, it tends to be a relatively inexpensive time to meet load, and in fact often features generation in excess of load. Indeed, decremental dispatch volume, used to adjust for overscheduling, exceeded incremental volume, used to adjust for under-scheduling, by a factor of approximately 7 to 4 in June 2006, as shown in Chapter 3, Figure 3.1.

Table 2.1 CAISO Annual Load Statistics for 2002 - 2006[2]

Year	Avg. Load (MW)	% Chg.	Annual Total Energy (GWh)	Annual Peak Load (MW)	% Chg.
2002 Actual	26,548		232,612	42,352	
2003 Actual	26,334	-0.8%	230,735	42,581	0.5%
2004 Actual	27,303	3.5%	239,231	45,597	6.5%
2005 Actual	26,989	-1.2%	236,481	45,562	0.1%
2006 Actual	27,426	1.6%	240,303	50,270	9.3%
2002 Adjusted	25,143		220,278	40,979	
2003 Adjusted	25,459	1.2%	223,047	41,063	0.2%
2004 Adjusted	26,429	3.7%	231,542	44,209	7.1%
2005 Adjusted	26,477	0.2%	231,962	44,260	0.1%
2006 Adjusted	27,426	3.5%	240,303	50,270	12.0%

Table 2.2 Rates of Change in Load: Same Months in 2006 vs. 2005[3]

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-06	1.8%	1.5%	2.5%	-0.7%
February-06	3.6%	3.3%	5.2%	3.1%
March-06	5.4%	5.1%	8.9%	5.0%
April-06	0.5%	0.4%	2.4%	0.1%
May-06	2.5%	2.8%	1.1%	-1.1%
June-06	12.3%	16.7%	7.0%	16.1%
July-06	8.0%	8.5%	7.3%	13.4%
August-06	-0.7%	-2.2%	1.8%	2.7%
September-06	6.4%	8.5%	5.3%	14.9%
October-06	-0.4%	-0.9%	0.2%	-6.0%
November-06	0.9%	1.3%	0.9%	3.6%
December-06	2.0%	1.5%	4.3%	2.6%

The impact of the July 2006 heat wave is evident in both Table 2.1 and Table 2.2. The annual peak load of 50,270 MW shown in Table 2.1 occurred on Monday, July 24. Table 2.2 demonstrates the impact the heat wave had on the overall load statistics for the month of July 2006. Specifically, average hourly loads in July 2006 were 8 percent higher than the same month in 2005. Additionally, the average daily peak and daily trough (low point) increased by 8.5 percent and 7.3 percent, respectively. The increase in the daily trough for July reflects the unusually high temperatures and humidity experienced in the off-peak hours of the heat wave. The July heat wave resulted in a substantial margin of hours above those seen in previous years. With nighttime low temperatures in the 80-90 degree range for many areas, nighttime

[2] Adjusted figures are normalized to account for day of week, changes in the CAISO Control Area footprint, and the 2004 leap year.

[3] This and all remaining tables and figures use calculations that have been adjusted for days of week, changes in load footprint, and the 2004 leap year, if applicable.

low loads reached approximately 30,000 MW during the peak week, approximately 3,000 MW above already significant nighttime lows seen during the month-long heat wave of 2005. Figure 2.1 compares loads in July 2006 to those in July 2005.

Figure 2.1 California ISO System-wide Actual Loads: July 2006 vs. July 2005

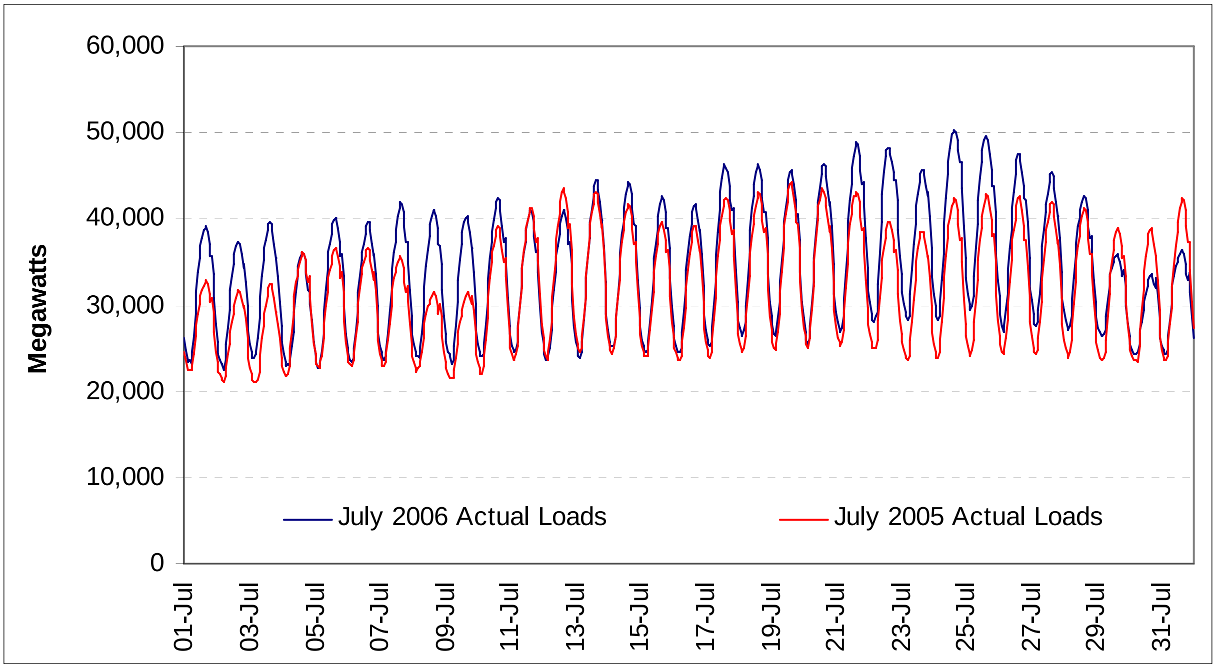


Figure 2.2 depicts load duration curves for each of the last five years and demonstrates the significant increase in load during 2006. Most striking in 2006 is the percentage of hours that load exceeded 40,000 MW, which used to be considered an extreme peak level. In 2006, hourly loads exceeded 40,000 MW in 3.2 percent of the total annual hours, compared to 0.8 and 1.6 percent in 2004 and 2005, respectively.

Figure 2.2 California ISO System-wide Actual Load Duration Curves: 2002 – 2006

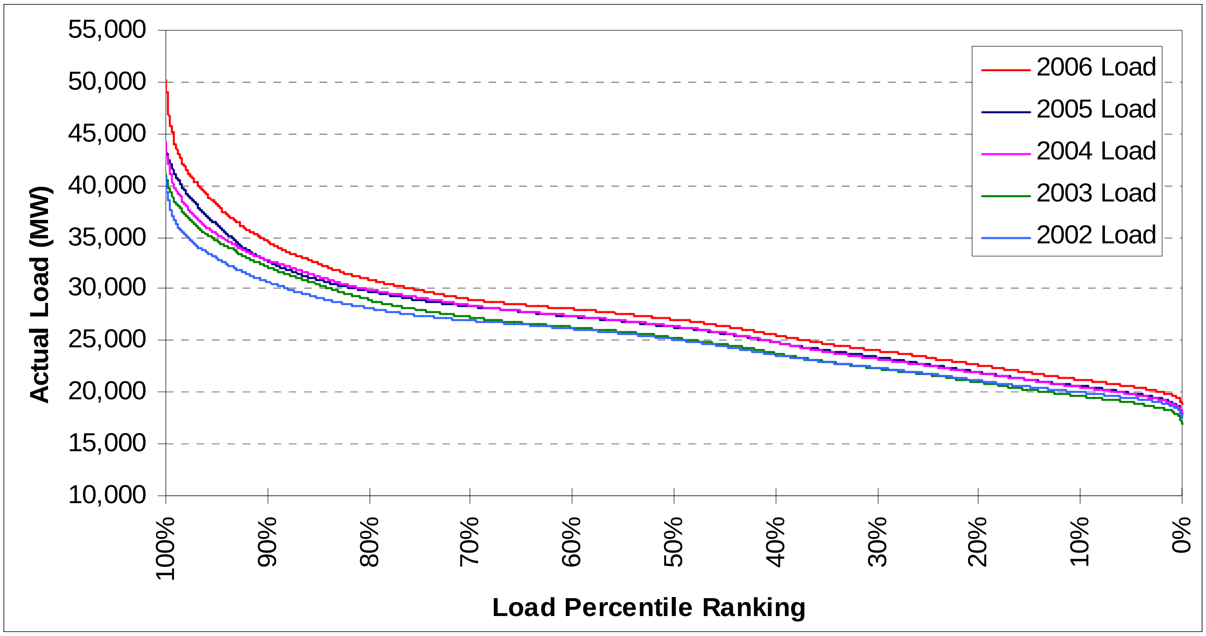


Table 2.3 shows yearly average load changes in NP26 and SP15, and for the CAISO Control Area as a whole. The NP26 all-time peak of 22,650 MW, set July 24, 2006 greatly exceeded the previous year's normalized peak of 19,934 MW, an increase of 13.6 percent. The SP15 all-time peak of 27,682 MW, also set on July 24, 2006, exceeded the prior year's SP15 peak of 26,459 MW, an increase of 4.6 percent.

Table 2.3 CAISO Annual Load Change: 2006 vs. 2005

Zone	Avg. Hourly Load	Daily Peak Load	Daily Trough Load	Annual Peak
NP26	3.6%	3.5%	4.7%	13.6%
SP15	3.6%	4.3%	3.2%	4.6%
ISO Control Area	3.6%	3.9%	3.9%	13.4%

Monthly load statistics for NP26 are provided in Table 2.4 and indicate that NP26 loads increased by all measures in every month of 2006 except for January and August. Of particular note is the dramatic increase in average energy consumption in June 2006, which shows that average hourly loads and average daily peaks increased by 11.6 percent and 14.9 percent, respectively. As noted above, June 2005 was an exceptionally cool month, which is the predominant driver for large load increases shown for this month in 2006.

Table 2.4 Rates of NP26 Load Change: Same Months in 2006 vs. 2005

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-06	-0.3%	-0.6%	1.3%	-0.8%
February-06	4.3%	3.6%	7.3%	5.3%
March-06	6.8%	6.1%	10.8%	6.8%
April-06	1.7%	1.4%	3.9%	8.2%
May-06	4.0%	5.5%	0.1%	2.4%
June-06	11.6%	14.9%	8.6%	13.8%
July-06	4.8%	4.2%	5.2%	13.6%
August-06	-1.9%	-4.2%	2.0%	0.7%
September-06	6.5%	7.6%	8.2%	14.2%
October-06	1.5%	0.8%	4.0%	1.2%
November-06	2.3%	1.8%	3.7%	3.1%
December-06	1.9%	2.1%	2.5%	3.7%

Table 2.5 shows monthly load statistics for the SP15 Region comparing 2006 values to the same month in 2005. Similar to the NP26 statistics, loads in SP15 increased in most months of 2006 by most measures. Most notable is the increase in load levels shown for June and July 2006. The June increases are, similar to NP26, primarily attributable to the unusually cool June experienced throughout California in 2005. However, the double digit increase in average energy consumption shown for July 2006 reflects the impact of the extraordinary heat wave.

Table 2.5 Rates of SP15 Load Change: Same Months in 2006 vs. 2005

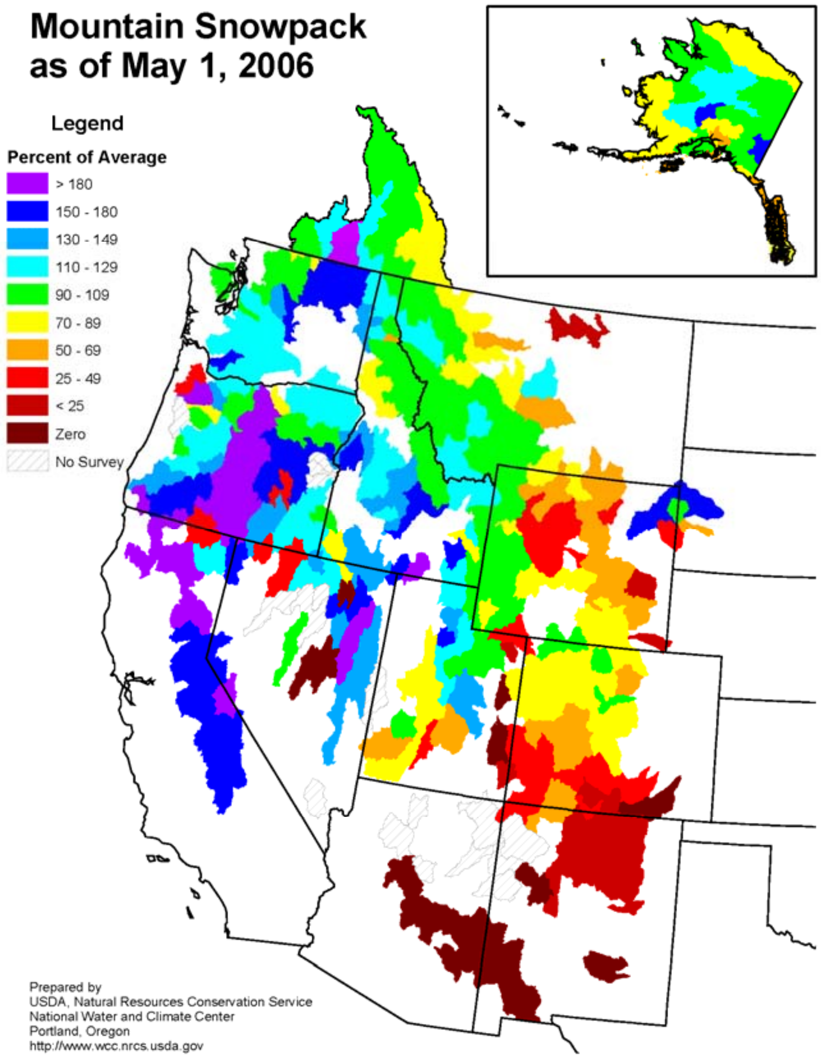
	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-06	3.7%	3.2%	3.6%	0.1%
February-06	3.0%	3.1%	3.4%	3.1%
March-06	4.3%	4.3%	7.6%	3.0%
April-06	-0.5%	-0.5%	1.1%	-0.9%
May-06	1.2%	0.6%	2.1%	1.2%
June-06	13.0%	18.1%	5.7%	23.8%
July-06	10.7%	11.8%	8.9%	4.6%
August-06	0.2%	-0.7%	1.8%	-2.5%
September-06	6.3%	9.4%	3.0%	18.0%
October-06	-1.9%	-2.1%	-3.1%	-9.7%
November-06	-0.2%	1.0%	-1.5%	10.0%
December-06	2.1%	1.2%	6.0%	1.9%

2.2 Supply Conditions

2.2.1 Hydroelectric

Snowfall in the California Sierra Nevada and in other Southwest ranges as well as the Pacific Northwest was generally well above average during the winter of 2006, which provided for robust runoff and storage among CAISO hydroelectric resources during the spring and summer. Figure 2.3 shows mountain snowpack across the Western United States as of May 1st, 2006.

Figure 2.3 Mountain Snowpack in the Western U.S., May 1, 2006[4]



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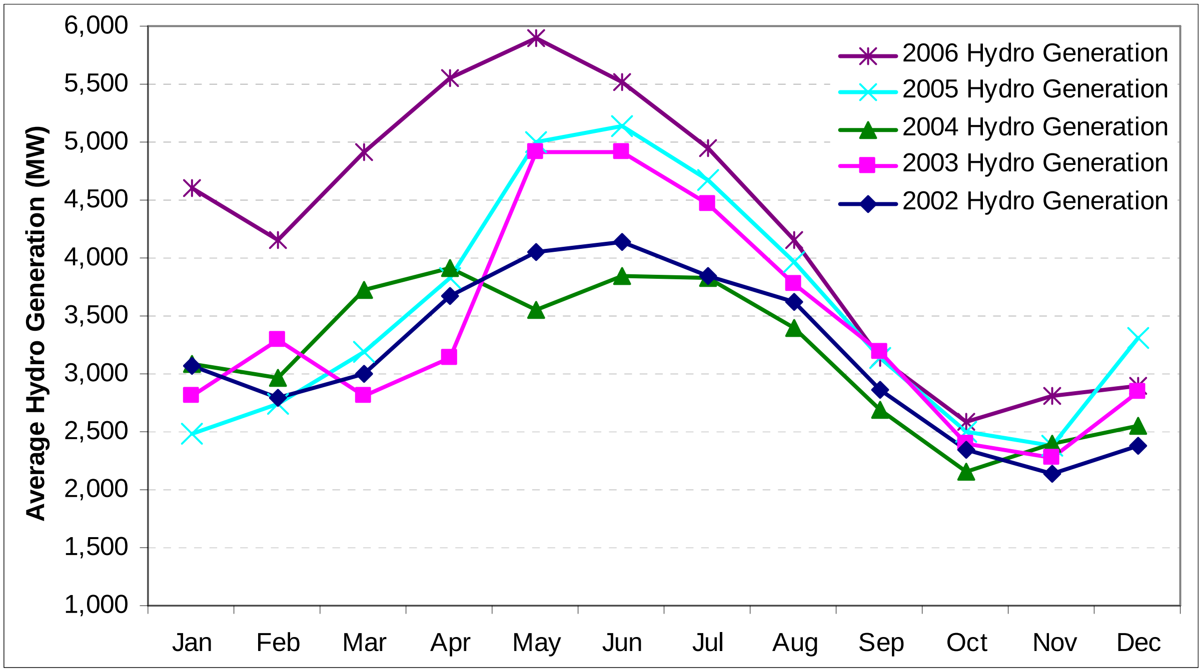
Given the robust snowpack within California, hydroelectric production exceeded the recent five-year range for the majority of 2006 (Figure 2.4). This was particularly true during the first half of 2006 with average hydro production in January through April between 40 and 60 percent greater than the previous four years. Hydro production remained at record levels throughout the summer but tapered off to more normal levels in the late summer to early fall.

[4] Source: USDA Natural Resources Conservation Service, http://www.wcc.nrcs.usda.gov/cgibin/westsnow.pl.

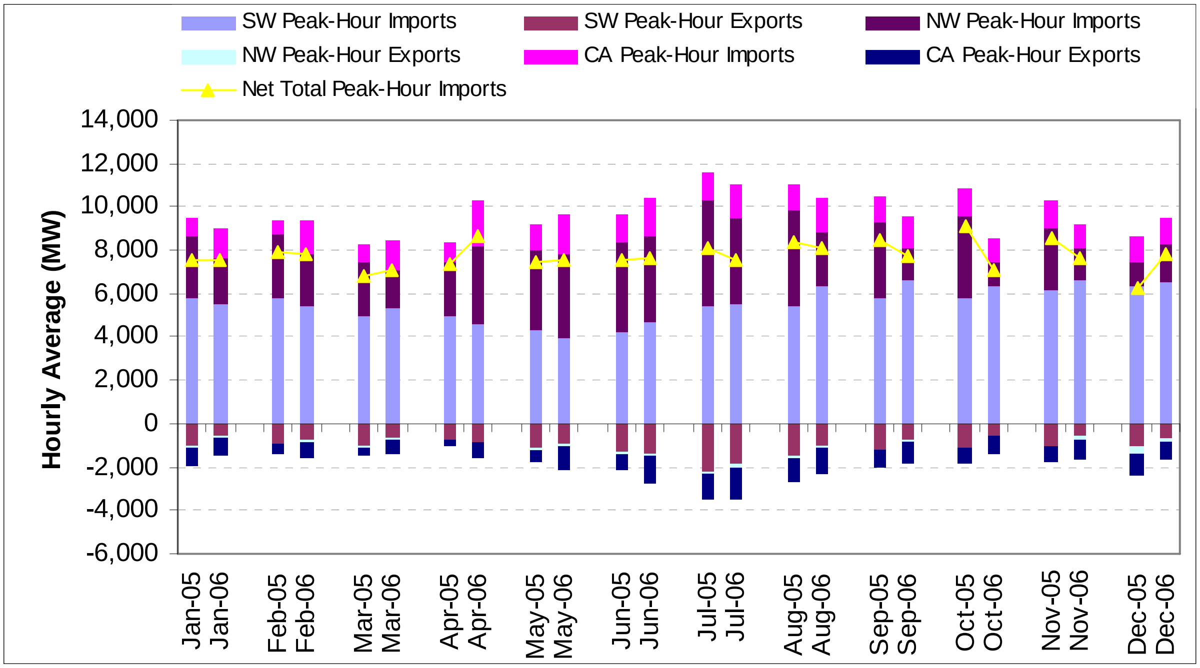
Figure 2.4 Monthly Average Hydroelectric Production: 2002-2006



2.2.2 Imports and Exports

Figure 2.5 compares peak imports and exports for each month in 2004 and 2005, and includes wheeled power. During the first three months of the year, the imports into and exports out of the CAISO Control Area remained almost the same level in 2006 as in 2005. They increased slightly in the spring (April – June) due primarily to an increase in imports from the Northwest. Average peak hour imports in 2006 were slightly lower during the peak summer months from July to September; an abundance of California hydroelectric power coupled with high generation availability within California likely contributed to the slight decline in average peak imports. Imports from the Southwest from October to December remained strong while imports from the Northwest dropped due to low demand.

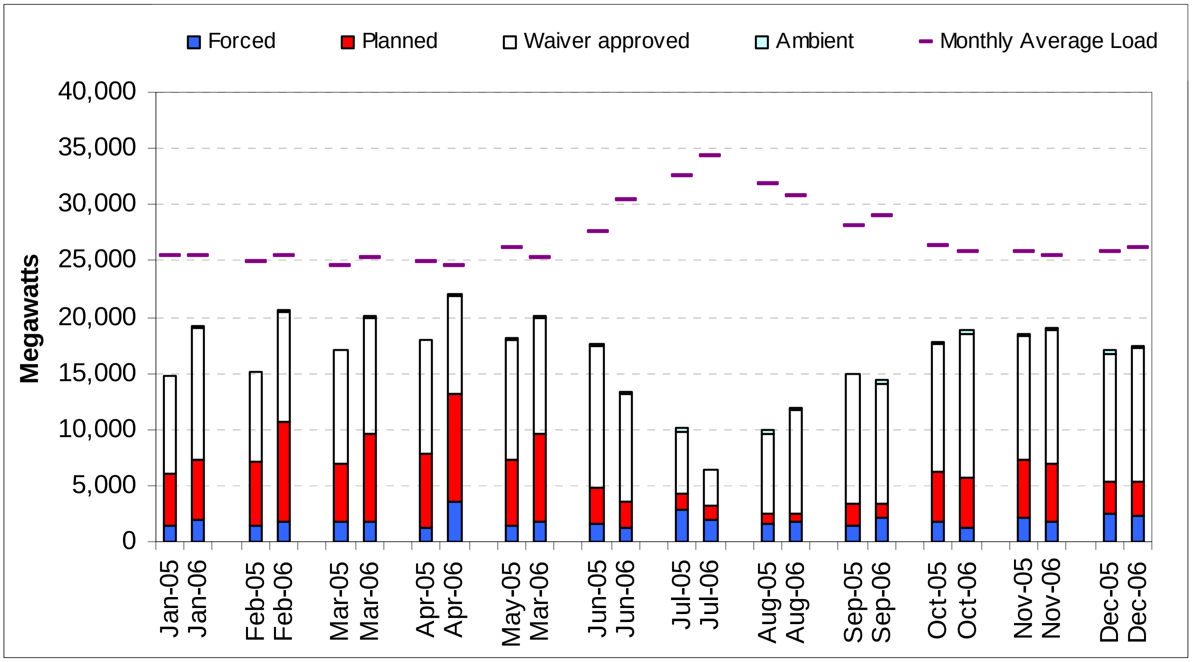
Figure 2.5 Year-to-Year Comparison of Monthly Average Scheduled Imports and Exports: 2006 vs. 2005



2.2.3 Generation Outages

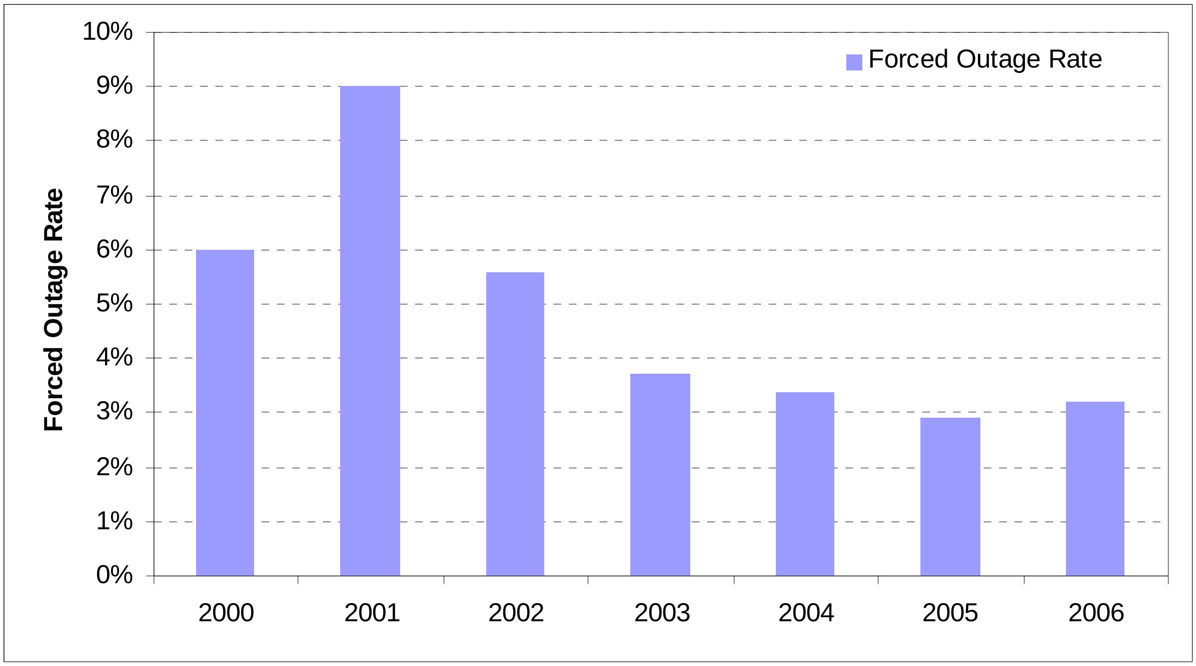
During the aforementioned July heat wave, the CAISO Control Area's entire generation fleet was operating seven days a week. For the entire duration of the peak of the heat wave, which lasted from July 17 to July 28, CAISO loads exceeded 45,000 MW on every day, even during the weekends. Peak loads were also exceptionally high during July 13 to July 16. This heat wave required that generation remain on continuously, even on weekends. Consequently, typical weekend maintenance was deferred. Despite this, generation forced outages remained very low throughout the heat wave. The low level of forced outages observed during the summer of 2006 is evident in Figure 2.6. This phenomenon is likely attributable to a very aggressive generation maintenance effort initiated in the spring months (as evident by the high level of planned outages shown for these months in Figure 2.6) and the increase in the energy bid cap from $250/MWh to $400/MWh. In addition, a high level of forward energy contracting provided an additional incentive for generation owners to undertake maintenance actions to avoid a forced outage during critical demand periods. The abundance of hydroelectric generation during the spring months helped in allowing a higher level of planned maintenance outages for thermal generation during this time.

Figure 2.6 Year-to-Year Comparison of Monthly Average Outages: 2006 vs. 2005



The overall forced outage rate in 2006 was the second lowest since 2000 at just above 3 percent. This is due primarily to the substantial increase in generation capacity in recent years, which has a decreasing effect on outage rates. Figure 2.7 below compares annual forced outage rates since 2000.

Figure 2.7 Year-to-Year Comparison of Forced Outage Rates: 2000-2006[5]

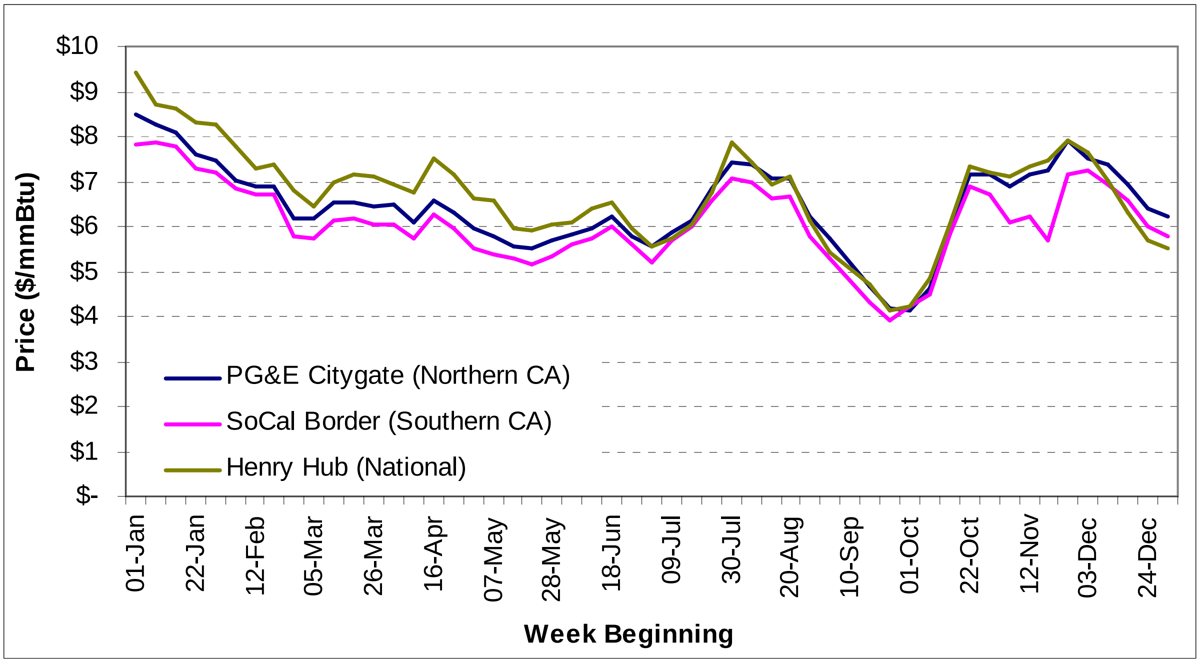


2.2.4 Natural Gas Prices

Natural gas prices in 2006 dropped significantly from the extreme prices experienced in the second half of 2005 stemming from the Gulf Coast hurricanes. Figure 2.8 shows weekly average gas prices for California delivery points (PG&E Citygate, SoCal Border) and compares those to Henry Hub. Prices at all locations were highest in January but declined steadily through February in response to a relatively mild winter peak heating season and higher than expected inventories. California gas prices were noticeably lower than Henry Hub during the first half of the year, perhaps reflecting differences in regional supply conditions as the sources of natural gas in the West are primarily West Texas, New Mexico, and Western Canada, which were not affected by the hurricanes. Nonetheless California prices were highly correlated to Henry Hub as many gas transactions are indexed to Henry Hub. California prices during the spring and early summer of 2006 hovered between $5-7/MMBtu but increased to over $7/MMBtu during July as high demands for power generation increased demand for natural gas. Prices declined in the September to October period as demand moderated and gas inventory levels remained steady. Northern California prices rebounded slightly in the November to December period due to some exceptional cold snaps that increased heating demand.

[5] This Annual Report now uses a methodology similar to one used by the California Energy Commission to count generation in the CAISO Control Area since 2001. As a result, forced outage rates differ slightly from those reported in previous Annual Reports. The generation additions and retirements data for 2006 are obtained on page 12 of the "CAISO 2006 Summer Loads and Resources Operations Assessment."

Figure 2.8 Weekly Average Gas Prices in 2006

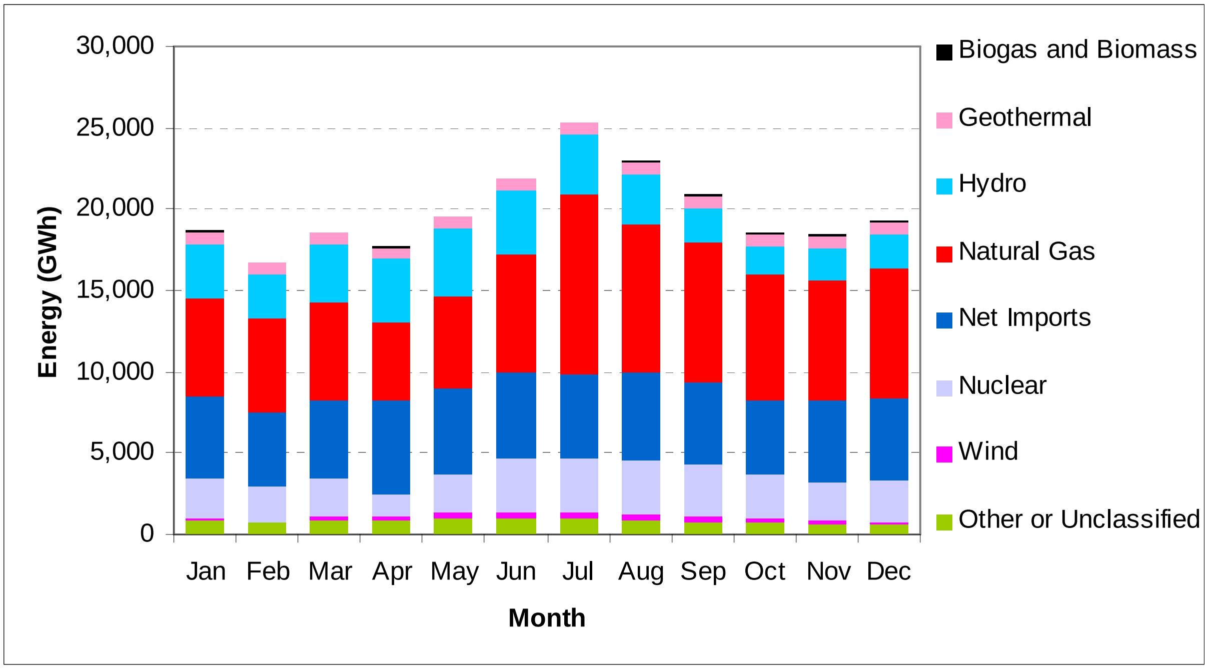


2.2.5 Generation by Fuel Source

A summary of monthly energy generation by fuel type is provided in Figure 2.9. Base-load generation sources, such as nuclear, geothermal, hydro, and cogeneration facilities, served between 28 and 37 percent of load each month in 2006. Between 21 and 33 percent of load was met by imports and 27 to 44 percent of load was met by natural gas units. The remaining 4 to 7 percent was served by wind and other generating resources. High loads in July resulted in a substantial percentage of load (44 percent) being served by natural gas-fired plants.

Use of intermittent renewable resources continues to pose challenges. In particular, the existence of wind does not always coincide with high loads. Wind blows predominantly at night, whereas loads peak during the day. For example, during the July 24 all-time peak, wind production in mid-afternoon averaged approximately 280 MW, of the 1,812 MW of installed wind capacity, or roughly 15.4 percent.

Figure 2.9 2006 Monthly Energy Generation by Fuel Type



2.3 Periods of Market Stress

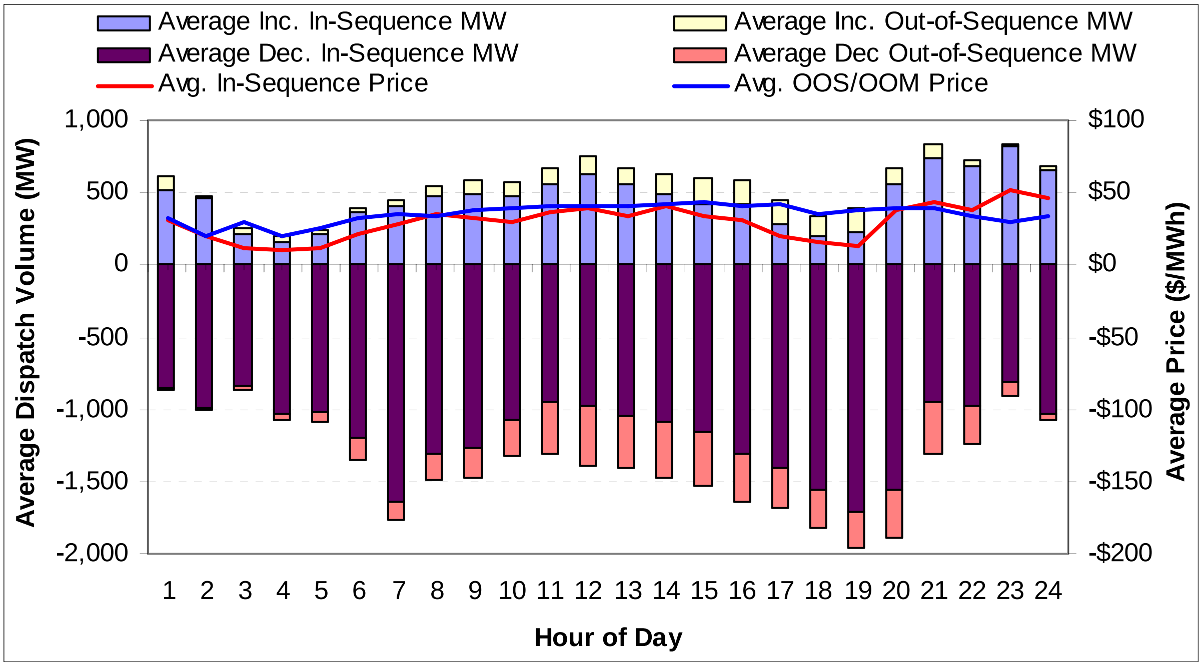
2.3.1 Spring Hydro Runoff

California experienced heavy rainfall and snow pack in the winter and early spring of 2006 that resulted in high hydroelectric production throughout this period as well, as seen in Figure 2.4 in Section 2.2.1. The exceptionally high hydroelectric production had market impacts in both the imbalance energy market, with excess production resulting in historically low imbalance prices, as well as the Ancillary Services Markets where unloaded online capacity available for reserves was diminished resulting in higher ancillary service prices.

Impact on the Real Time Energy Market

During the winter and early spring, Scheduling Coordinators generally scheduled generation and imports quite close to their actual load, which when combined with positive uninstructed generation from hydro resources, QFs, wind, and thermal units operating at minimum load caused the CAISO to dispatch generation and imports predominantly in the decremental direction in the imbalance market. This was most pronounced in April. The relatively low average prices, particularly in early morning hours, reflected a strong supply condition consisting primarily of hydroelectric energy in California and the Pacific Northwest. The low loads and strong supply during these off-peak periods often resulted in near-zero or even negative prices for real-time energy. Figure 2.10 provides an hourly profile of net real-time dispatch volumes, both in and out of sequence, and average prices, for the month of April.

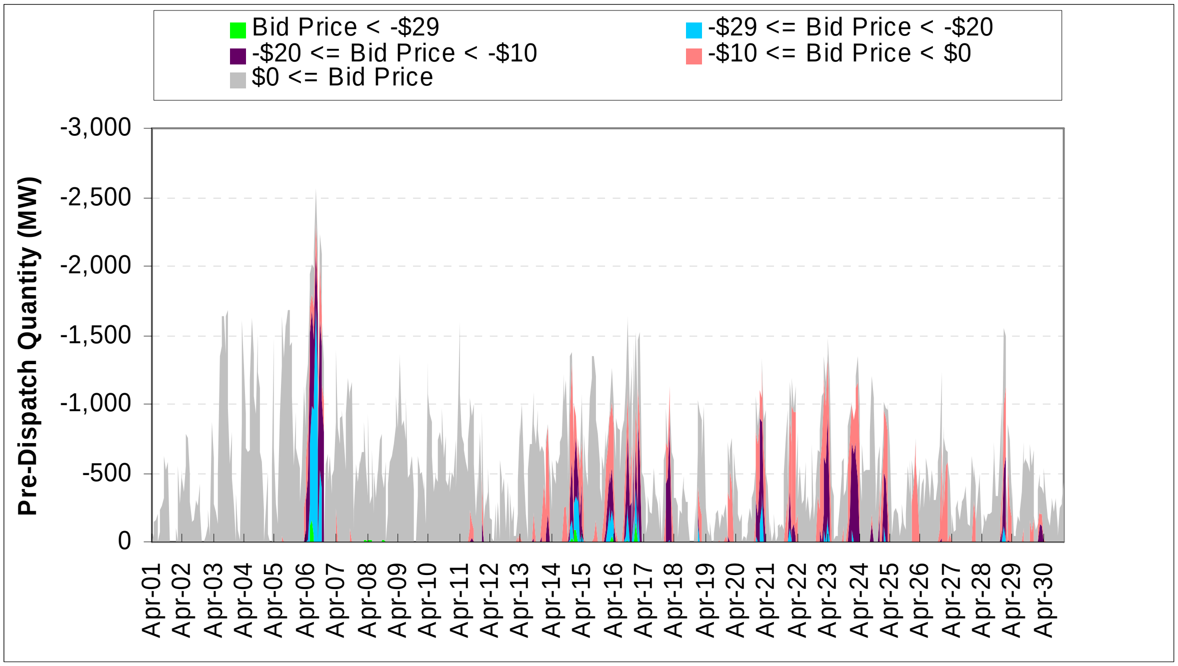
Figure 2.10 Hourly Profile of ISO Average Incremental and Decremental Dispatch and Price, April 2006



The strong Pacific Northwest hydroelectric production and frequent transmission congestion into Northern California resulted in a structural difference between spot energy prices in these two areas, where spot energy prices in the Pacific Northwest were well below those in Northern California for much of the spring.

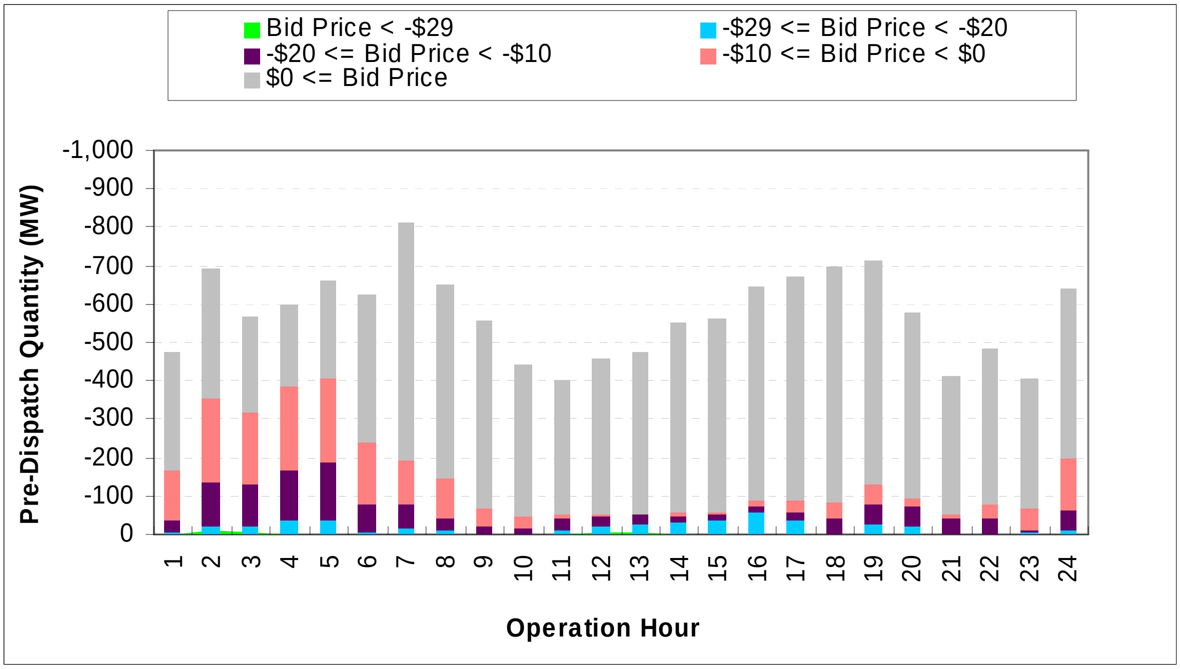
System conditions this spring also resulted in an unusual and high degree of loop flow mitigation, where unscheduled counter-clockwise loop flows were causing north-to-south congestion on Path 26. This physical phenomenon was due in part to the unusually high hydroelectric production in Northern California and the Pacific Northwest. The forward congestion management markets do not account for unscheduled flow, and as a result the impacts of unscheduled flow must be mitigated through the Real Time Market. This mitigation was done both in the process for pre-dispatching inter-tie bids prior to the start of the Real Time Market for each operating hour and by dispatching internal resources on a 5-minute basis within the operating hour. To effectively manage loop flows in the Real Time Market, CAISO Grid Operators often set the Path 26 transfer limit during the inter-tie pre-dispatch process below its physical capacity when they anticipated unscheduled flow, making the reduced limit binding in the north-to-south direction (the direction of unscheduled flow). This created a buffer on Path 26 to accommodate the unscheduled flow and resulted in a need to export energy to the Pacific Northwest in the pre-dispatch phase of RTMA. The lower spot energy prices in the Pacific Northwest were also observed in the pre-dispatch export energy prices, where prices for real-time exports were often negative, indicating that participants in the Pacific Northwest region had to be paid to take energy from the CAISO. Figure 2.11 shows pre-dispatched export volumes in several negative price categories.

Figure 2.11 Hourly Pre-dispatch of Inter-tie Bids by Price Bin for April 2006



Average pre-dispatch quantities are shown by bid price bin, with emphasis on negative bid prices, hours 1 through 24 in Figure 2.12. This figure shows that the majority of pre-dispatched exports with negative bid prices were in the off-peak hours and that the negative prices for these dispatches were largely between -$20/MWh and $0/MWh, with some exports priced between -$29/MWh and -$20/MWh showing up in both peak and off-peak hours.

Figure 2.12 Average Pre-dispatch of Inter-tie Bids by Hour by Price Bin for April 2006

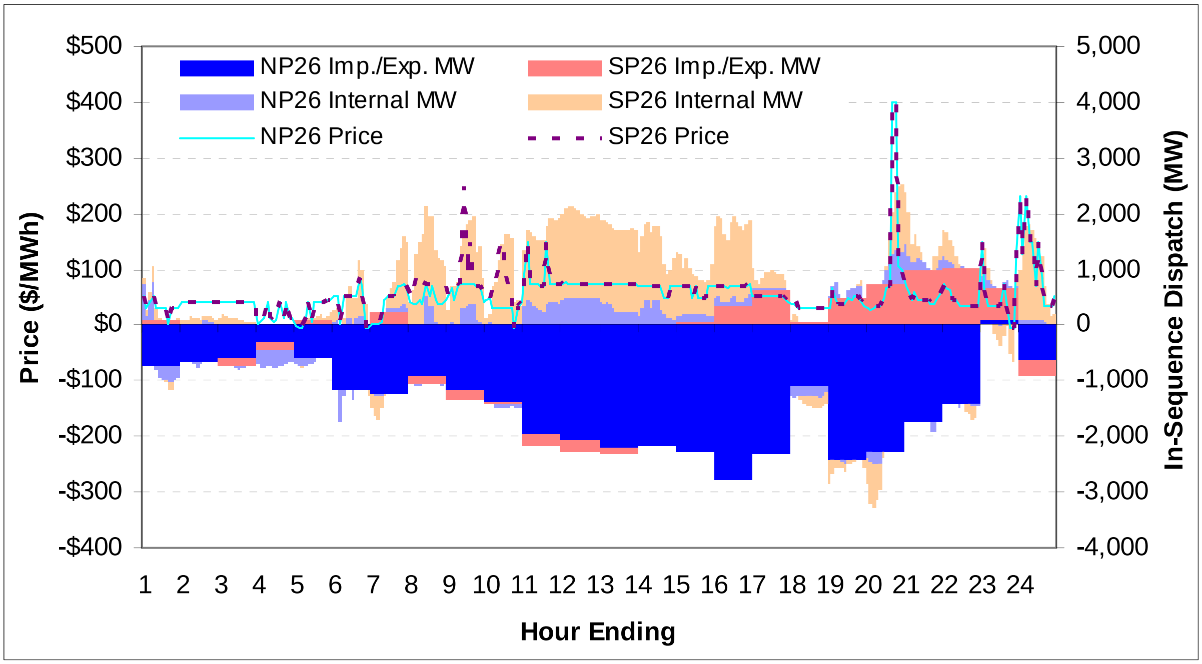


In addition to the high export volumes to the Northwest, pre-dispatch imports into Southern California were constrained by the Southern California Import Transmission Nomogram (SCIT), which is a physical limit on the instantaneous import of power into the Los Angeles basin. Because of this constraint, the CAISO had to rely more heavily on internal resources to provide SP15 balancing energy. Unlike imports, this pool of internal resources is dispatchable on a five-minute basis to meet imbalance requirements. However, due to the SCIT limitation, manual intervention in the dispatch of internal resources was necessary to ensure that only SCIT-resolving resources were dispatched, which would generally exclude resources outside the Los Angeles basin.

Because actual system conditions can and typically do vary from the anticipated conditions that the loop flow mitigation actions were based on, Path 26 often remained partially unloaded in real time. As a result, NP26 internal resources were able to be used for incremental real-time balancing – including addressing incremental energy needs in the South – which helped to decrease the frequency of SP26 price spikes.

The loop flow mitigation process, which is an important and necessary reliability tool, often resulted in pre-dispatching a relatively large amount of export bids from NP26 prior to the start of the operating hour and then dispatching incremental five-minute energy from SP26 within the operating hour, which created south-to-north counterflows on Path 26 to offset the north-to-south loop flow. However, as noted above, to the extent loop flow is less than expected, Path 26 can become un-congested in real-time and incremental five-minute bids from NP26 can also be dispatched to meet the imbalance demands created by the pre-dispatched exports. Figure 2.13 shows an example of this dispatch pattern, for April 6, 2006. The pattern was especially prominent in Hours Ending 11:00 to 15:00 (10:00 am to 3:00 pm). On this day, Path 26 was congested in the day-ahead market in the north-to-south direction for all but the first six hours of the day, and PACI (the primary interchange between California and the Pacific Northwest) was congested two hours in the day-ahead market. This indicates that given persistent unscheduled flows from north-to-south, additional exports from NP15 to the Northwest would be required to mitigate real-time congestion on Path 26 for most of the day and on PACI for potentially a significant portion of the day. This increase in demand for exports resulted in the CAISO dispatching significant volumes of export energy in the pre-dispatch at bid prices below $0/MWh. The dark blue and coral regions are hourly blocks of pre-dispatched exports and imports, while the light purple and yellow regions are five-minute internal dispatches.

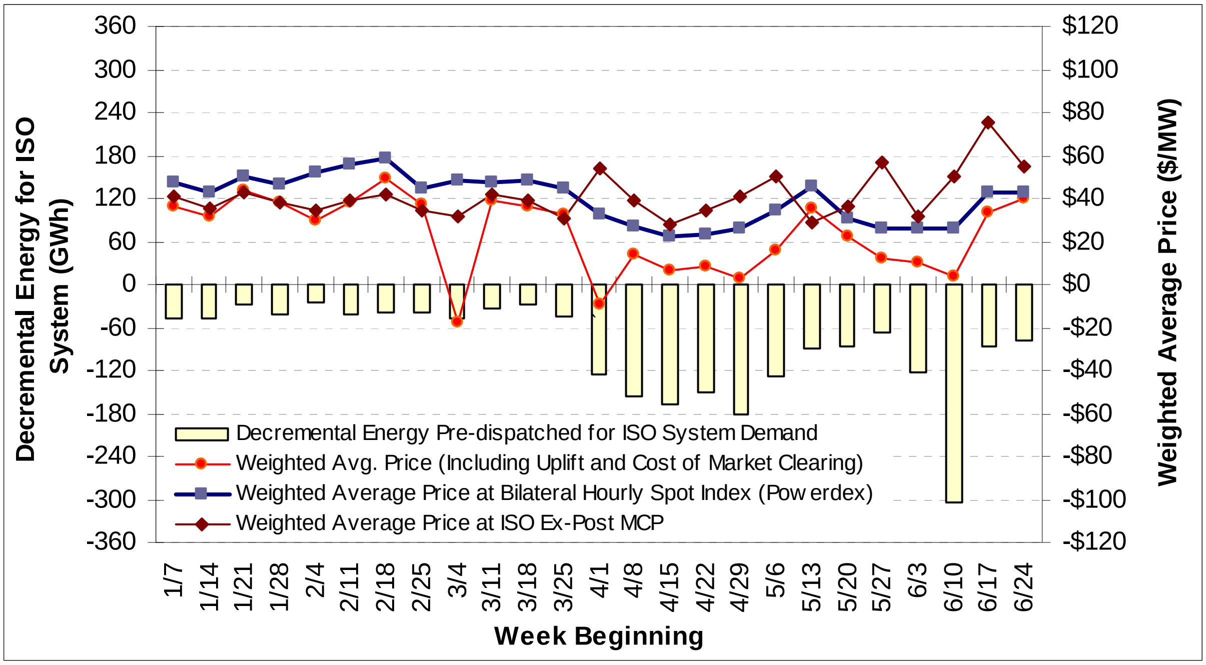
Figure 2.13 Pre-dispatch and Internal Dispatch Quantities for April 6, 2006



Volumes of pre-dispatched export bids approximately tripled in April compared to dispatch levels observed in the three prior months. In addition, prices for pre-dispatched exports diverged from 5-minute imbalance prices and dropped well below the real-time market clearing price at which 5-minute dispatchable resources are settled, as shown in Figure 2.14. Figure 2.14, which is based on weekly reports filed with FERC and posted on the CAISO website pursuant to Amendment 66, shows weekly total pre-dispatched export energy, the average actual cost of that energy based upon export bid prices (denoted by the red line), the average cost had that energy been priced at the day-ahead bilateral price (denoted by the blue line), and the real-time market-clearing price (denoted by the brown line).

The two trends highlighted in Figure 2.14 – high volumes of pre-dispatched exports at prices lower than the real-time price paid for instructed and uninstructed energy within the CAISO system – create an imbalance in real-time energy payments made and received by the CAISO that is ultimately allocated to LSEs based on their share of total CAISO load. In effect, this revenue imbalance is created when pre-dispatched energy is exported at relatively low prices, but instructed and uninstructed energy within the CAISO system to serve those exports is paid a higher real-time MCP (or bid price for OOS energy).

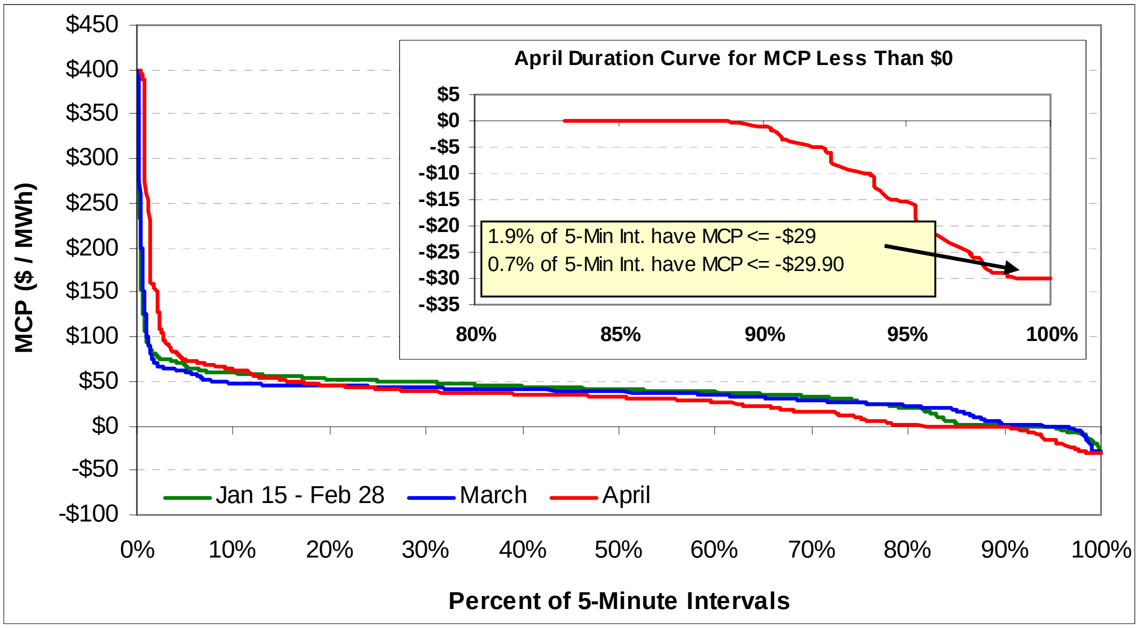
Figure 2.14 Price Divergence Between Real Time Pre-dispatch and Five-Minute Dispatch (January – April 2006)



The revenue imbalance created by the divergence between pre-dispatch prices and real-time 5-minute prices for the month of April alone was approximately $20 million, or over $1/MWh of total system load. However, a significant portion of this cost may have been offset by payments received for positive load imbalances and/or instructed and uninstructed energy from resources owned or controlled by LSEs (e.g., hydro, wind, and minimum load energy from some thermal units).

In addition to price divergence between pre-dispatch and 5-minute interval prices, the high hydroelectric output during the winter and spring also resulted in increased frequency of low real-time (5-minute) prices which were, again, most pronounced in April as seen in Figure 2.15.

Figure 2.15 Duration Curves for 5-Minute Interval MCPs in NP26 for Three Periods – January 15 through February 28, March, and April.



Given the low real-time prices observed during this period, questions were raised as to whether the current -$30/MWh soft bid cap for decremental energy bids in the CAISO Real Time Market was appropriate or should be lowered to attract additional decremental offers to help meet the reliability needs observed during periods of persistent surplus generation. An inset chart is included in Figure 2.15 to provide some insight into how frequently the -$30/MWh decremental bid price cap was binding during the peak runoff period when the CAISO's demand for decremental energy was highest.

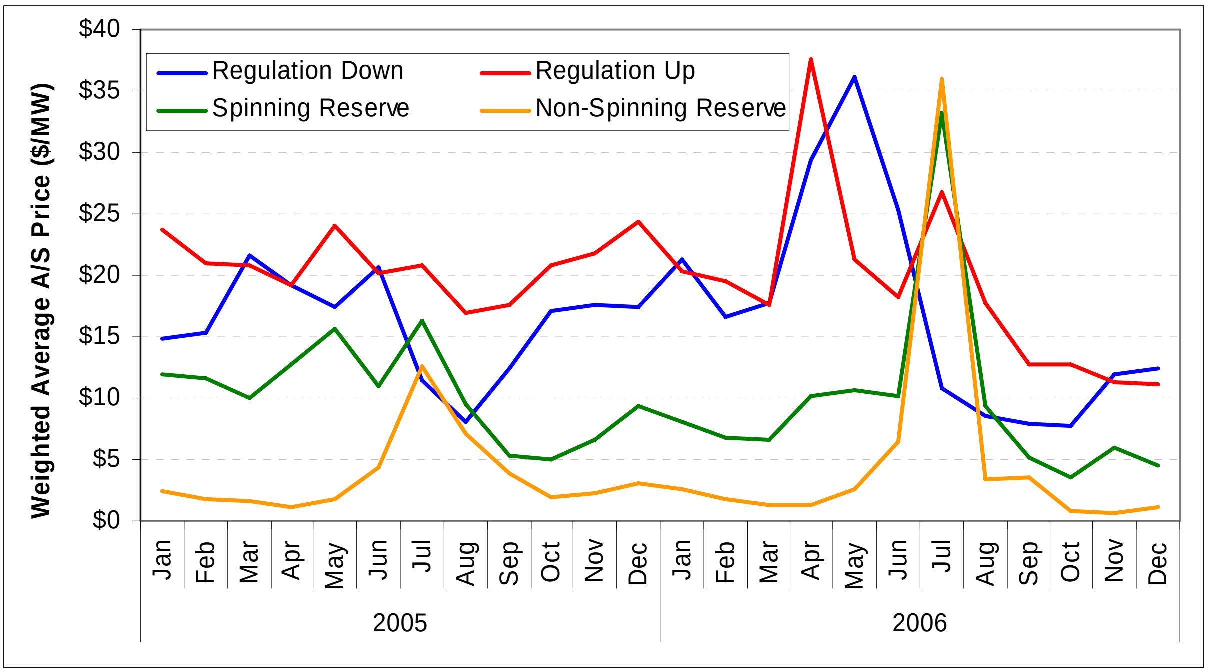
In April, the NP26 real-time price, which is predominantly the lower of the two zonal prices when Path 26 is congested, was below -$29/MWh in 1.9 percent of intervals, and below -$29.90/MWh in 0.7 percent of intervals. In addition, the frequency of pre-dispatched export bids below -$29/MWh was also very small in April, accounting for approximately 0.6 percent of bid volume overall (not shown) and the volume in this price range reached a peak of only 9 percent of pre-dispatch export bids on April 6. Moreover, the frequency of extremely negative bids for all export bids (even those not dispatched) was also very low, as shown in Figure 2.11.

Ancillary Service Bid Insufficiency and Price Spikes

The high hydroelectric output also had two notable impacts on the Regulating Reserve markets. The first was that the increased hydroelectric production displaced (more expensive) thermal generation to meet load during this period, which resulted in less thermal generation being on-line to provide Regulation Reserve. The second impact was that hydro resources were generally operating at maximum capacity during the winter and spring period which eliminated their Regulation Up capacity altogether. As for their Regulation Down capacity, reservoirs were filling up quickly and these hydro resources were running at maximum capacity to keep reservoir levels below maximum and at the same time avoid "spilling" water, or allowing water to pass without using it to generate electricity. Spilling water in this context is generally considered to be "wasted" energy since that water cannot be used later at that facility to produce electricity, so hydro resource owners were generally less willing to reduce output (via Regulation Down) in lieu of serving load with that energy. This resulted in a thinner supply of offers to provide Regulation Down Reserve.

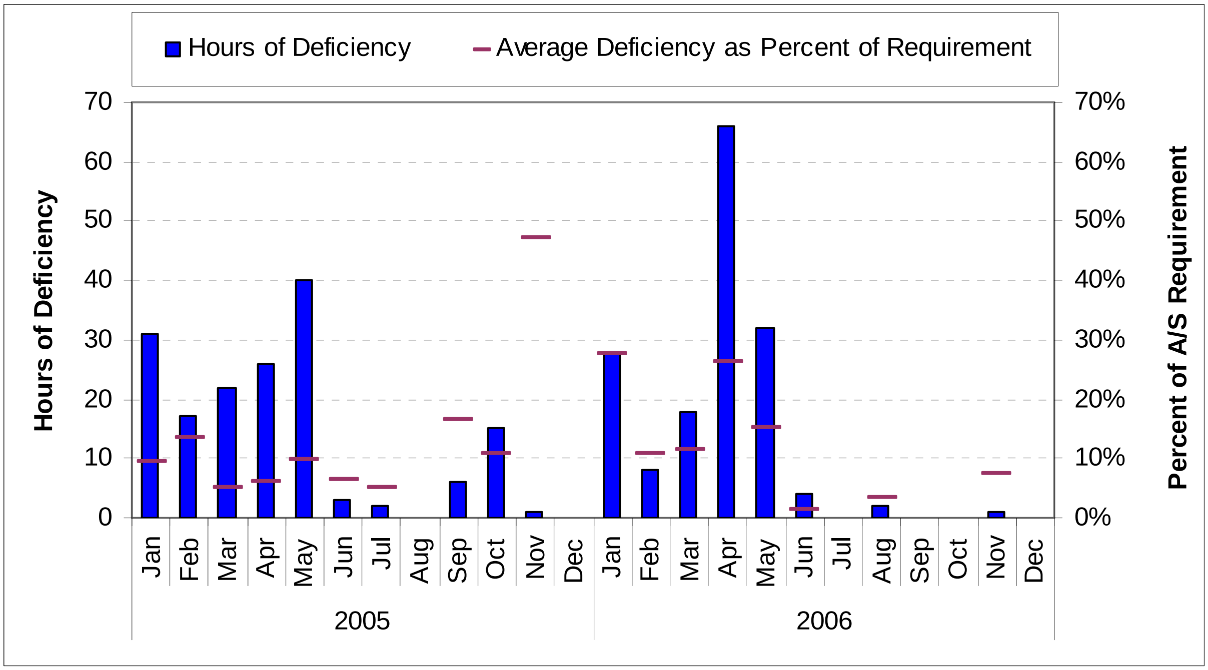
The price impact of high hydroelectric production in the winter and spring can be seen in Figure 2.16 below, where market clearing prices in the Regulating Reserves spiked in April and May.

Figure 2.16 Monthly Average Ancillary Service Market Clearing Prices



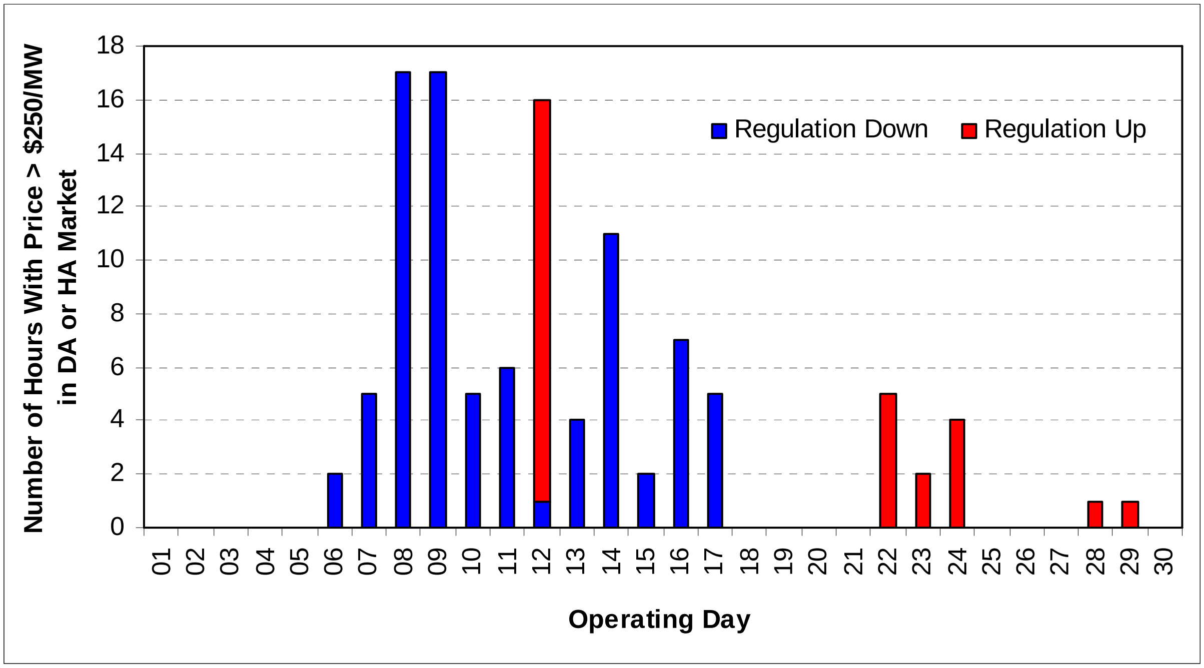
The price spikes in Regulating Reserve during April and May can be directly attributed to hours of bid insufficiency where supply of these reserves was reduced by the impacts of high runoff on hydroelectric production and consequent reduction of supply of Regulating Reserves. Figure 2.17 shows the dramatic increase in bid insufficiency for the Regulation Down market, with over 65 hours of bid insufficiency and an average deficiency of 27 percent during April.

Figure 2.17 Frequency of Bid Insufficiency in Regulation Down



During hours of reduced supply of Regulation bids, and in the extreme an absolute shortage of bids, the CAISO was forced to procure reserves from all available bids including those high-priced bids that would have otherwise not been economic during times of bid sufficiency. This caused persistent price spikes, primarily in the Regulation Down market, in the first half of April, as seen in Figure 2.18.

Figure 2.18 Regulating Reserve Price Spikes in April 2006



These price spikes were persistent for over a week in April. However, the higher prices appear to have elicited some supply response (greater quantity bid in at decreasing prices) toward the end of the price spike period, which mitigated the duration of the price spike period. The impact of the high runoff period on Regulating Reserve prices is covered in more detail in Chapter 4.

2.3.2 Heat Wave of July 5-28, 2006

The most significant market event of the summer season was the July heat wave, which resulted in record-breaking energy demand on several days and above-average demands for most of July. Despite the unprecedented demands being placed on the Western power grid during this period, wholesale energy markets and CAISO grid operations performed extremely well. However, the CAISO Real Time Market prices were well below prevailing bilateral prices during much of the heat wave period, raising concerns about the efficiency and functioning of the CAISO Real Time Market. A close examination of overall market performance during this period revealed the following observations:

- **The level of forced outages in the CAISO Control Area was remarkably low considering the severity and duration of the heat wave.** This unusually high level of generation availability is likely attributable to several factors: 1) the concerted effort the CAISO and generator community made to prepare for the summer months; 2) a high level of forward contracting and increase in the energy bid cap to $400/MWh, which created a strong incentive for unit owners to maintain their units so as to avoid the spot market exposure of a forced outage during critical peak periods; and 3) implementation of the CPUC Resource Adequacy program – which introduces the potential to have forced outages this year count against a generating unit's Qualifying Capacity for RA sales in future years.

- **The CAISO Real Time Market prices were generally well below prevailing day-ahead bilateral prices during much of the heat wave.** Prevailing forward bilateral energy prices during extreme system peaks often reflect scarcity and risk premiums (i.e., an aversion to not being able to cover contract positions or serve load) and therefore often depart from marginal cost pricing (i.e., prices reflect demand's willingness to buy rather than the marginal cost of supplying the energy). In contrast, prices in the CAISO Real Time Market are based on the marginal supply bid and depend largely on the demand for imbalance energy and available supply. Throughout most of the heat wave period, CAISO LSEs typically scheduled almost all of their energy demand in the forward markets – leaving very little demand left for the imbalance market. Consequently, prices in the CAISO Real Time Market tended to be much lower than prevailing forward bilateral prices. Other factors that have historically dampened CAISO Real Time Market prices include unscheduled minimum load energy from units denied must-offer waivers and pre-dispatched inter-tie energy. However, these factors were not found to be significant during the heat wave period.

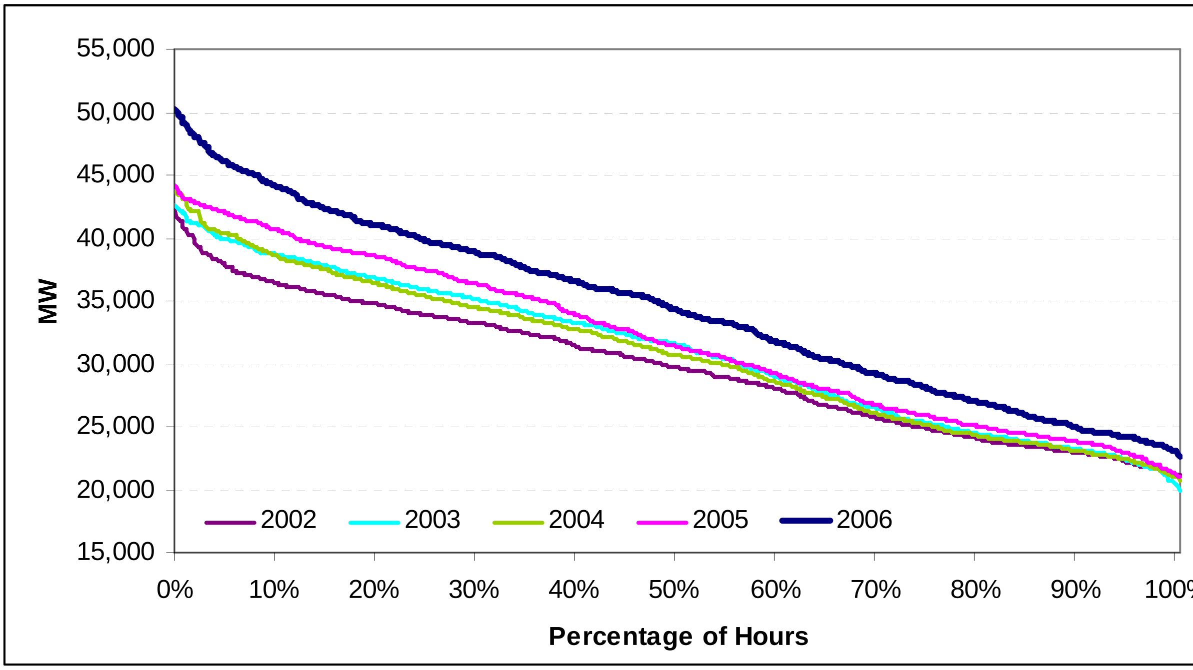
- **Prices in the CAISO Ancillary Service Markets generally followed prevailing day-ahead bilateral prices during much of the heat wave.** Since ancillary services are procured on a forward basis (day-ahead and hour-ahead), they reflected the opportunity costs of offering the generation capacity as reserve as opposed to selling the energy in the bilateral market.

- **The CAISO Ancillary Service Markets suffered from bid insufficiency during the most critical days of the heat wave.** Bid insufficiency in the A/S markets was particularly acute on the all-time peak day of July 24 and was a major reason for the need to declare a Stage 2 Emergency and trigger interruptible load programs. The reserve shortage conditions existed despite the fact that there were unused bids in the imbalance energy stack and moderate imbalance prices primarily in the $55 to $100 range with a few intervals pricing near $400/MWh. This outcome highlights two deficiencies in the current Real Time Market design: 1) an inability to procure operating reserve in real-time, and 2) a lack of a reserve shortage scarcity pricing mechanism.

Loads and Schedules

During the July 2006 heat wave, peak load records were set three times. On July 17, 21, and 24, load successively set record peaks at 46,545 MW, 49,014 MW, and 50,240 MW, respectively. In comparison, the CAISO 2006 Summer Assessment forecasted "1-in-2" and "1-in-10" scenario peaks of 46,063 and 48,723 MW, respectively. Even more extraordinary was the persistence of extreme load conditions through much of July. Figure 2.19 compares duration curves of July 2006 loads (loads ranked from highest to lowest) to July load duration curves for the previous four years.

Figure 2.19 July CAISO Load Duration Curves: 2002-2006



As shown in Figure 2.19, hourly loads in July 2006 exceeded 45,000 MW in approximately 8 percent of the total hours of the month and exceeded 40,000 MW in approximately 24 percent of the total hours of the month – compared to 0 and 12 percent, respectively, in July 2005. The unusually high level of load in all hours of the month in July 2006 reflects the high level of humidity associated with this heat wave that kept temperatures up throughout the day and evening hours.

Every day of the heat wave featured peak loads above 45,000 MW, a level that had previously been reached (adjusted for changes in the footprint) in approximately 3 hours in the CAISO's 10-year history. Indeed, four days of this heat wave, including one Saturday, featured peaks above the 1-in-10 scenario. Fortunately, a hydro-rich spring, vigilant generator maintenance, and grid upgrades enabled the system to meet these unprecedented demand levels. The CAISO's 2006 Summer Assessment predicted total supply at 51,600 MW. This estimate turned out to be slightly conservative, coming in approximately 2.4 percent below the actual available supply at the July 24 peak.[6]

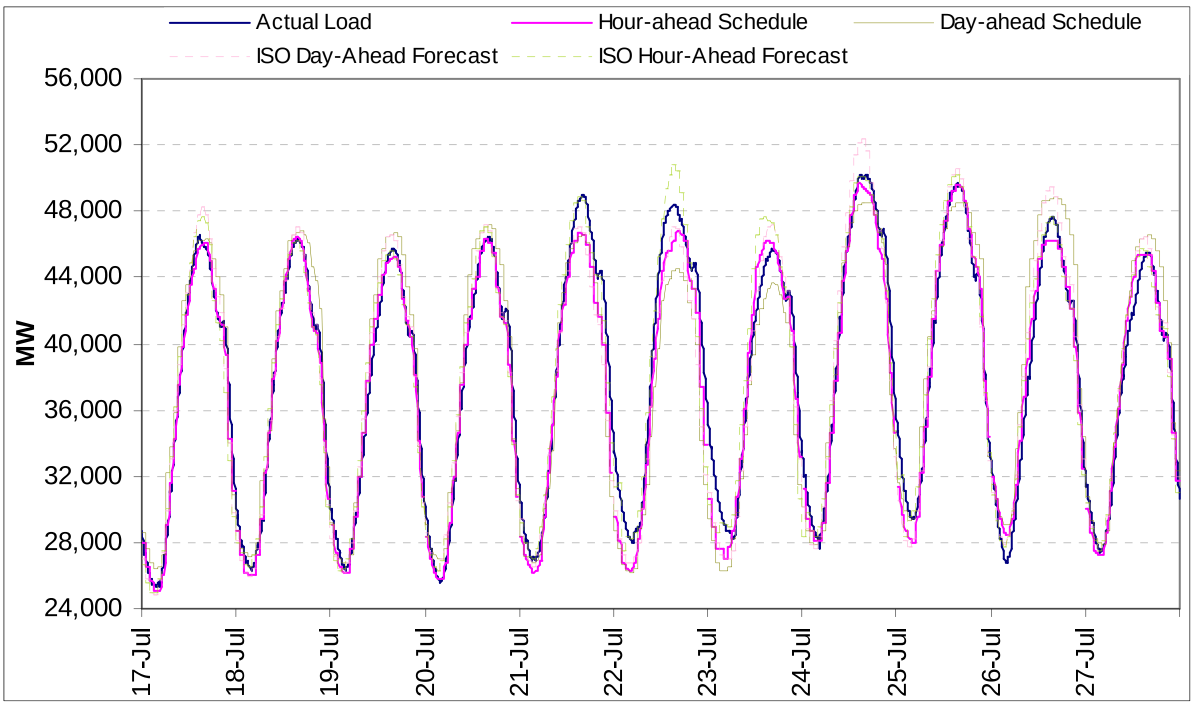
Forward scheduling was substantial, covering at least 95 percent of load at every peak during the heat wave. In addition, little generation was committed through the CAISO must-offer waiver denial process. Nearly all generation was self-committed in response to high day-ahead market price signals. The hour-ahead schedule on Saturday, July 22, was only 90.9 percent of forecast, but 95.4 percent of actual load, as demand response by certain pump load facilities reduced the actual load by approximately 800 MW. The peak on Monday, July 24, was also shaved by approximately 835 MW through curtailing interruptible loads.

[6] The peak load of 50,240 MW, plus the actual operating reserves of 5.2 percent at that time, totals 52,852 MW. Source: California ISO OASIS.

One largely unanticipated feature of this heat wave was the exceptionally high loads in Northern California. Most of the adverse summer planning scenarios predicted an extraordinary heat wave within the SP26 load pocket, with Path 26 and perhaps other key transmission corridors fully congested into SP26. As it happened, during the July 24 peak, the SP26 zonal peak was 27,692 MW, much closer to the 1-in-2 forecast of 27,299 MW than its 1-in-10 forecast of 29,561 MW. The heat wave's unforeseen load levels were driven primarily by energy consumption in NP15, where the peak of 22,726 MW exceeded the zone's 1-in-10 forecast by 6.2 percent.[7] With such high load levels in both the North and South, Path 26 was not congested during the peak, and power in fact flowed toward NP26 at times.

Figure 2.20 compares actual load to forecasts and schedules for July 17 through 27. Table 2.6 compares daily peak loads to their schedules and forecasts for the same period.

Figure 2.20 Actual Loads vs. Day-Ahead and Hour-Ahead Schedules and Forecasts, July 17-27



[7] California ISO, *2006 Summer Assessment,* p. 7.

Table 2.6 Daily Peak Loads vs. Hour-Ahead Schedules, Forecasts and Real-Time Prices during the Daily Peak, July 17-27[8]

Date	Hour	Peak Load (MW)	HA schedule (MW)	HA Schedule as % of Actual Load	HA Forecast (MW)	HA Schedule as % of HA Forecast	RT price
17-Jul	15	46,545	45,771	98.3%	47,481	96.4%	$ 75.00
18-Jul	16	46,356	46,476	100.3%	46,230	100.5%	$ 103.01
19-Jul	16	45,784	45,184	98.7%	45,578	99.1%	$ 71.92
20-Jul	17	46,421	46,112	99.3%	46,672	98.8%	$ 150.00
21-Jul	17	49,014	46,578	95.0%	48,576	95.9%	$ 399.00
22-Jul	16	48,447	46,193	95.3%	50,798	90.9%	$ 58.64
23-Jul	17	45,728	46,064	100.7%	47,328	97.3%	$ 62.12
24-Jul	15	50,240	49,691	98.9%	50,100	99.2%	$ 80.06
25-Jul	16	49,695	49,563	99.7%	50,157	98.8%	$ 66.95
26-Jul	16	47,723	46,198	96.8%	47,614	97.0%	$ 382.00
27-Jul	16	45,527	45,384	99.7%	45,617	99.5%	$ 73.56

On July 17, loads set a record peak of 46,545 MW, which stood until July 21. Hour-ahead schedules exceeded 95 percent of both actual peak loads and forecasted peaks on each of these four days, and outages ranged between 2,000 and 3,000 MW, a range that is considered below the "Most Likely" condition.

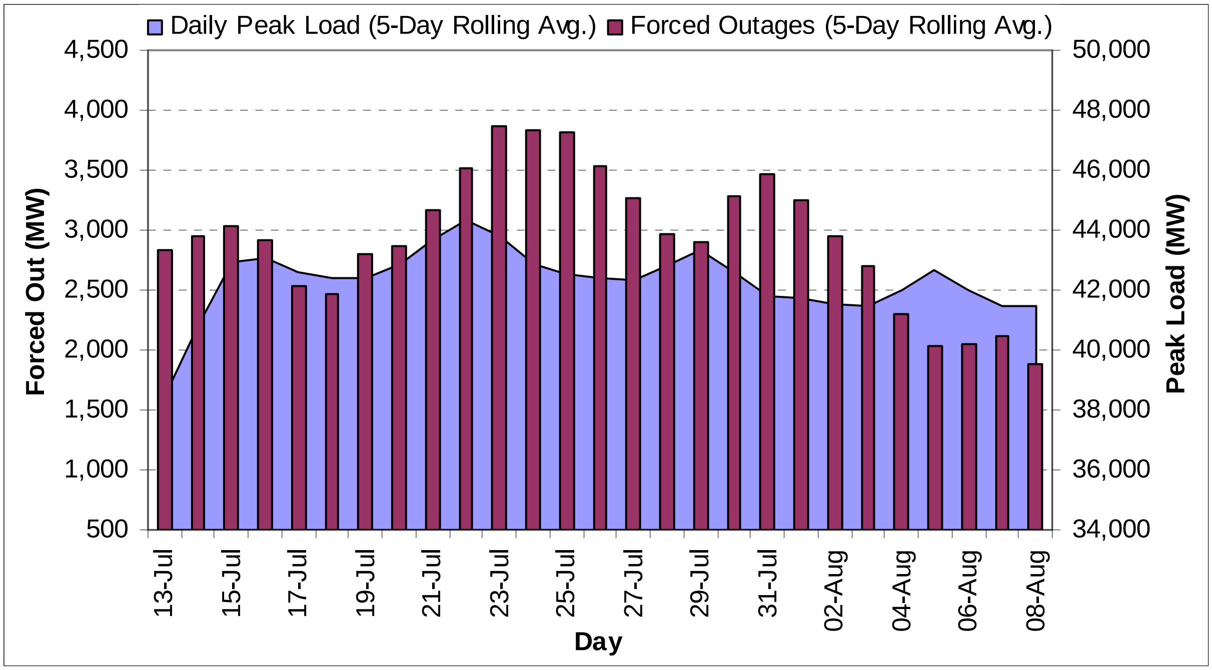
Generation Outages

A prolonged heat wave, such as occurred in July, typically results in high rates of generation forced outages, as the continuous operation of generation under high temperatures and high output stresses equipment – often to the point of failure. In the July heat wave, despite unprecedented load levels for an extended period, the rate of generation forced outages stayed uncharacteristically low.

The differences between forced outage levels in the July 2006 heat wave compared to forced outage rates in prolonged heat waves in 2005 can be seen by comparing Figure 2.21 and Figure 2.22 below. Figure 2.21 compares daily peak loads and forced outage levels for summer 2005 based on a 5-day rolling average. In 2005, the five-day rolling average daily peak reached its maximum of 44,356 MW on July 22, 2005, approximately the 12th straight day of peak loads above 40,000 MW. The 2005 five-day rolling average of forced outages on this day was 3,523 MW and had increased steadily between July 20 through July 23. A similar pattern is evident for the heat wave that crested on July 29, 2005 with forced outages increasing steadily from approximately 2,900 MW on July 29 to 3,500 MW on July 31, 2005.

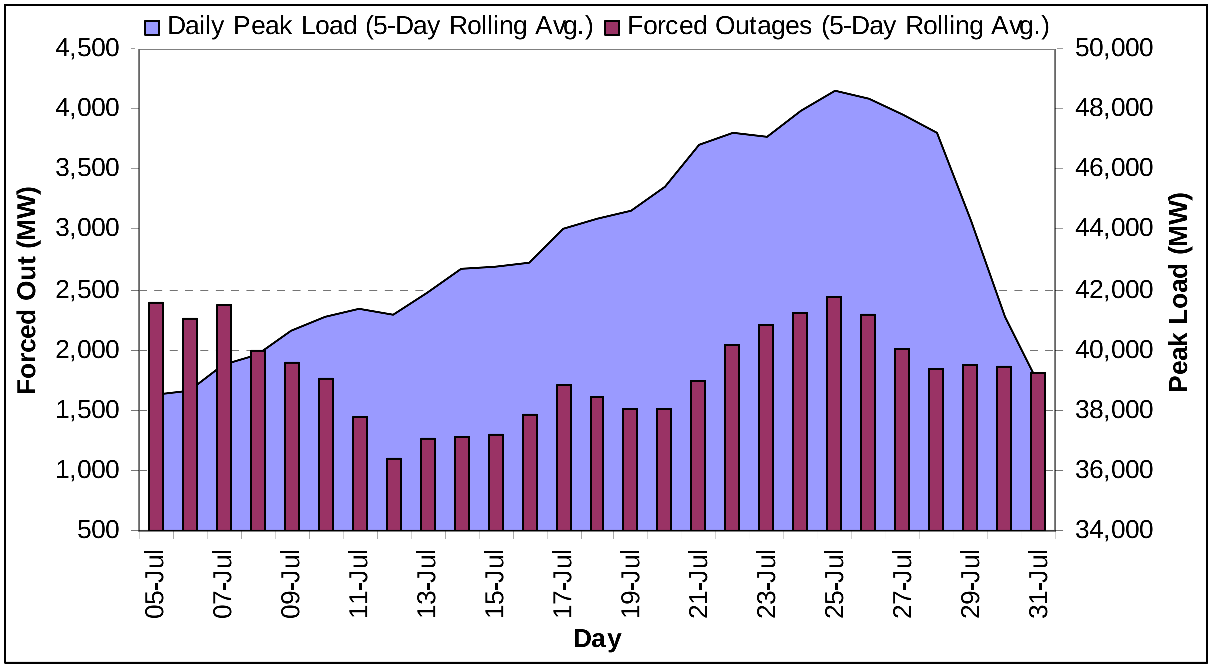
[8] July 24 peak was prior to curtailment.

Figure 2.21 2005 Peak Load vs. Forced Outages: Five-Day Rolling Averages



In contrast, there is much less of a pattern of increasing forced outages during the July 2006 heat wave (Figure 2.22). The 2006 five-day rolling average of daily peak loads reached its maximum on July 25, approximately the 19th consecutive day on which peak load exceeded 40,000 MW. At this time, the 2006 five-day rolling average of forced outages only reached 2,445 MW – approximately 30 percent below the 2005 level, despite occurring later in a period of continuous high-load days.

Figure 2.22 2006 Peak Load vs. Forced Outages: Five-Day Rolling Averages



The unusually low level of forced outages during the July 2006 heat wave is likely attributable to several factors.

- A higher degree of summer preparedness by the generation community through coordination and planning with the CAISO.
- The increase of the West-wide price cap from $250 to $400/MWh on January 14, 2006 – coupled with high levels of forward energy contracting, which provides additional incentive for generators to be available when spot prices are likely to be high.[9]
- Generation availability incentives provided by the CPUC's Resource Adequacy (RA) program, which went into effect June 1, 2006. The RA program introduces the potential to have forced outages this year count against a generating unit's Qualifying Capacity for RA sales in future years.

[9] When the majority of load is covered by forward energy contracts, the spot market risk of high energy prices is shifted to the supply side of the market. A generator that is serving forward energy contracts has a greater incentive under a higher bid cap to avoid a forced outage, as they will bear the price risk of having to replace that energy from the spot market. Additionally, generation that is not serving forward energy contracts has a greater incentive under a higher bid cap to be available during the critical peak days in order to sell at potentially higher spot market prices.

Bilateral and Real-Time Prices

During the recent heat wave, and particularly on the peak load day of July 24, the CAISO's real-time prices remained relatively moderate, generally ranging between $50 and $100/MWh with occasional and brief excursions as high as $399/MWh. Given the record-setting load during this period and corresponding high spot bilateral prices, the relatively low range of real-time prices appears counterintuitive. However, it must be recognized that CAISO Real Time Market prices are largely driven by the amount of imbalance energy required as opposed to total system demand. Throughout most of the heat wave period, CAISO load serving entities typically scheduled almost all of their energy demand in the forward markets – leaving very little demand for the imbalance market. Indeed, 98.9 percent of load at the peak on July 24 was scheduled, leaving an imbalance of approximately 552 MW, a level that is very typical, and indeed modest, for a summer peak. With adequate supply available to meet this relatively low level of energy imbalance, prices in the CAISO Real Time Market tended to be much lower than prevailing forward bilateral prices. This trend is evident in Figure 2.23, which compares daily peak hour prices for the day-ahead bilateral market and CAISO Real Time Market for July 2006.

Figure 2.23 Actual Peak Load vs. Day Ahead Bilateral and Real Time Peak-Hour Prices

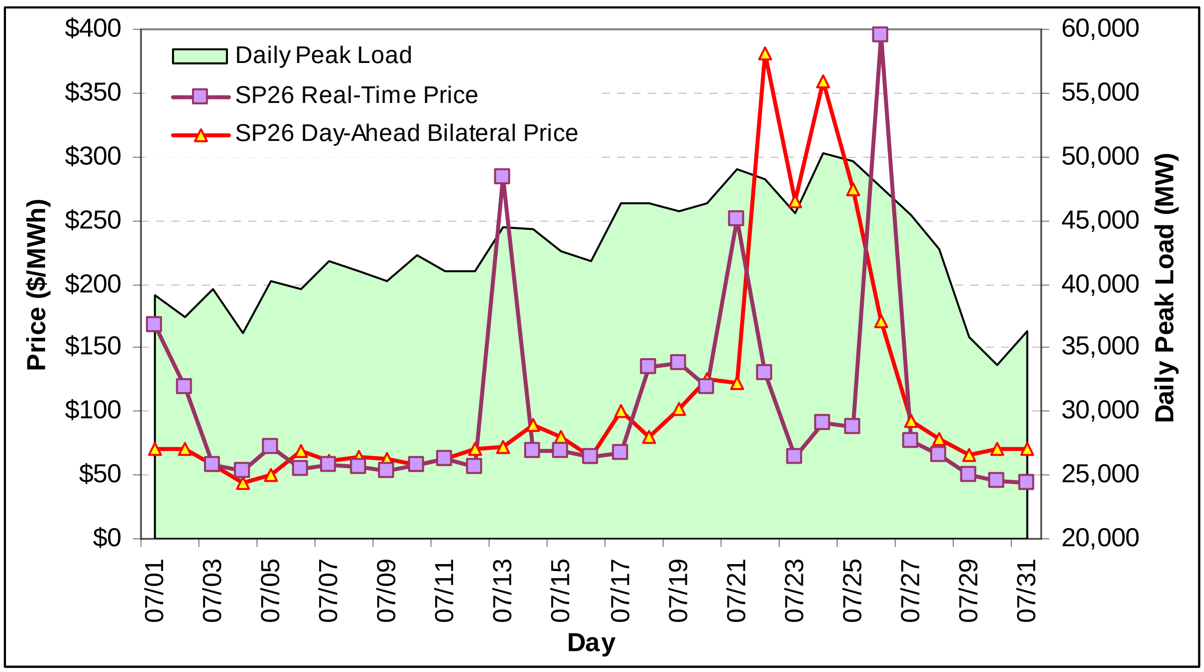


Figure 2.23 shows that peak day-ahead bilateral prices increased dramatically during the crest of the heat wave (July 22 – 25) when loads were at their highest – but the hourly CAISO Real Time Market prices during those same peak hours actually declined and were substantially below day-ahead bilateral prices.

In addition to a high level of forward scheduling, other historically significant factors that may have dampened CAISO Real Time Market prices include unscheduled minimum load energy from units denied must-offer waivers and pre-dispatched inter-tie energy. However, these factors were not that significant during the heat wave.

- No more than five resources were ever committed at any one time through either the FERC must-offer process or the Resource Adequacy process during the heat wave. All other generators were self-committed through bilaterally-negotiated transactions, indicating a larger proportion of load met by scheduled energy forward of real-time.
- Pre-dispatch of inter-tie energy was moderate given the high degree of forward scheduling and limited real-time import capacity with the Northwest.
- A more detailed assessment of the role of must-offer waiver denials and pre-dispatch of inter-ties during the heat wave is provided below.

Must-Offer Waiver Denials

The CAISO uses its day-ahead load forecast in determining unit commitments in the day-ahead must-offer waiver process. When day-ahead load forecasts are significantly below the actual load, fewer units are committed and online to offer energy in the imbalance market than would have been required if the load forecast were closer to actual.

Due largely to high day-ahead bilateral contract prices, few units were left without self-commitments during the peak week. Those units that were not self-committed were eventually committed through must-offer and/or RA commitments. In each hour between July 17 and 27, between two and five units from a pool of only nine distinct units (one combined cycle and eight steamers) were committed. Given the peak load was 50,240 MW, these resources represent up to 2.9 percent of peak load. The following chart shows minimum and maximum potential loads of RA- and must-offer-committed units, and the total number of units committed, for each hour between July 17 and 27.

Figure 2.24 Capacity Committed through FERC Must-Offer and RA Processes During Crest of the Heat Wave

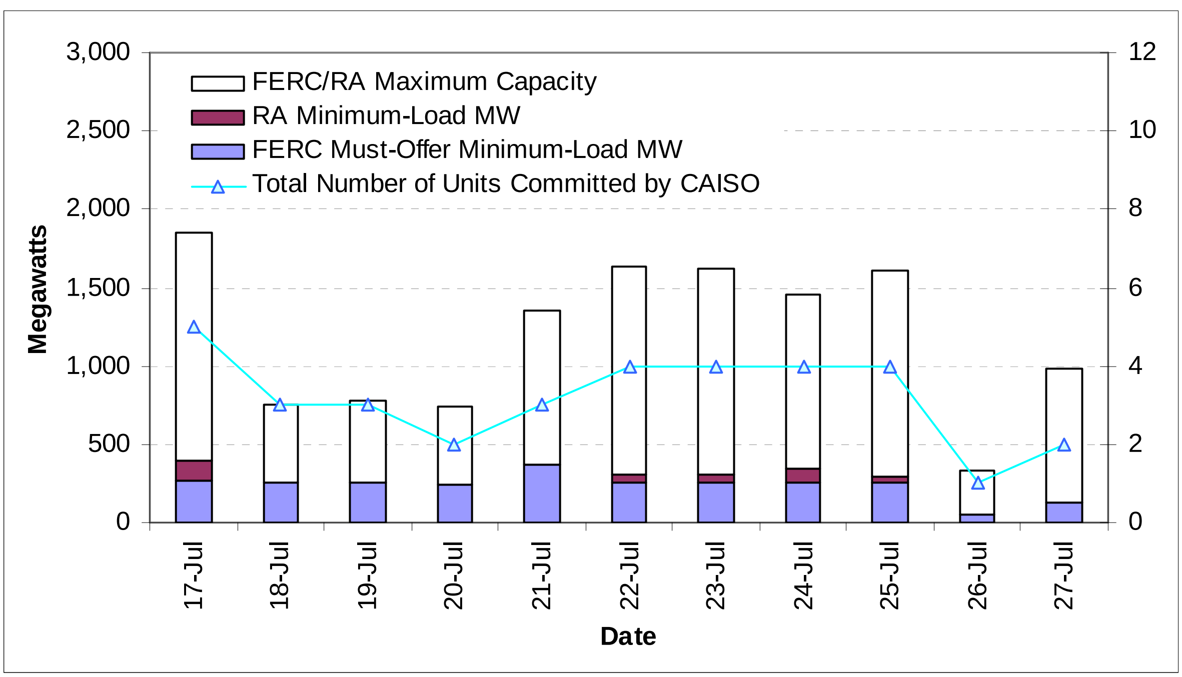
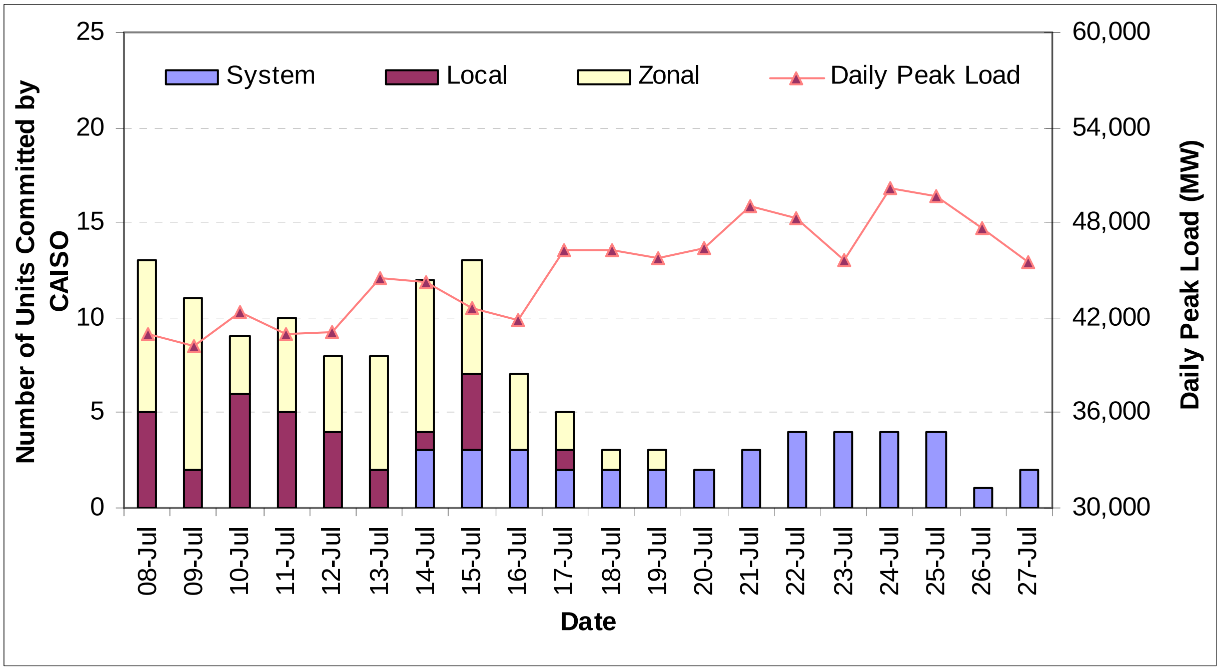


Figure 2.25 Units Committed during Heat Wave by Commitment Type

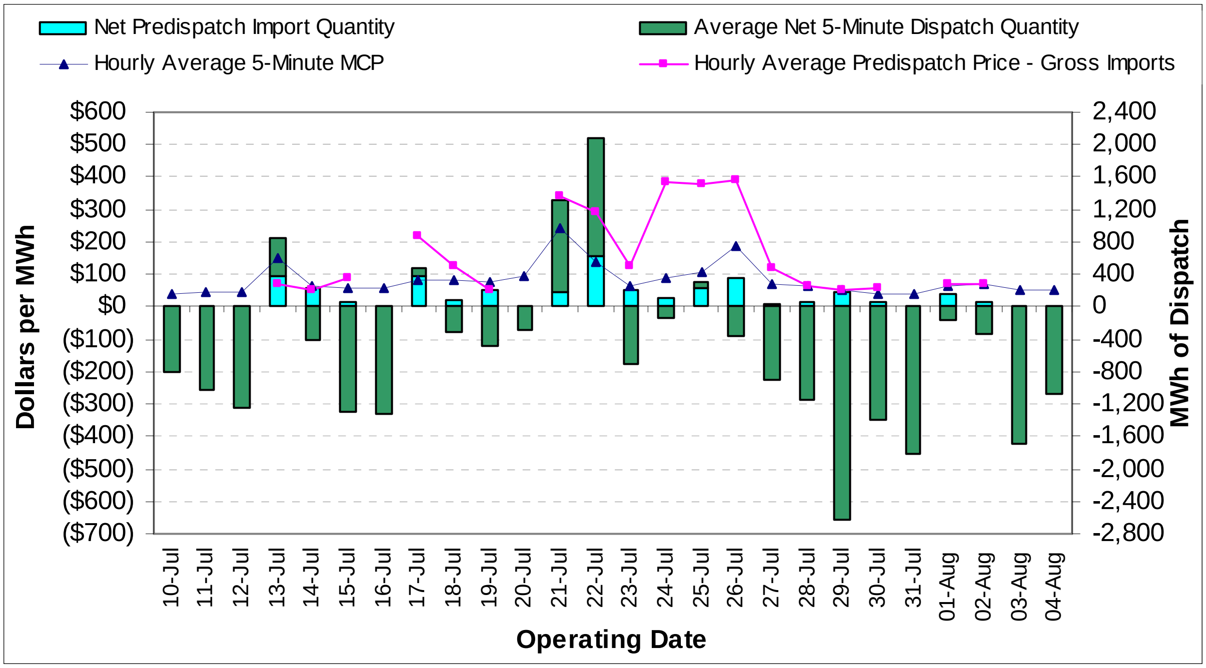


Pre-dispatched System Resources

Another potential driver of 5-minute real-time prices is the level of system resources (imports) that are pre-dispatched prior to the start of the operating hour. These imports contribute to meeting the imbalance requirement (as do 5-minute dispatches of internal resources) but are not eligible to set the 5-minute real-time price. Pre-dispatched bids across the inter-ties are paid "as-bid" and may have an average settlement price that diverges from the 5-minute interval price. During the high load days from July 21 through July 26, the average pre-dispatch import price did diverge from the average 5-minute price paid to internal resources dispatched in real-time, as seen in Figure 2.26 below. During the period of greatest price divergence, July 24 - 26, the average net import quantity cleared through the pre-dispatch was relatively small, averaging under 400 MW, as most neighboring areas also reached record loads and had few resources available for export during the West-wide heat wave. The price divergence effectively evaporated toward the tail end of the heat wave. While the average pre-dispatch import price during the period July 24 - 26 does not appear to be strongly correlated with average 5-minute imbalance prices, it is strongly correlated with day-ahead spot bilateral prices.

While this divergence may create revenue imbalance charges (note there were average 5-minute decremental dispatches on some days with a significant price divergence), the greater concern lies with the potential incentives a persistent divergence like this may have on participation in the 5-minute real-time market. If this price divergence were persistent, it would create incentives for internal generating resources with available capacity to export energy outside the CAISO Control Area rather than offer it in the 5-minute real-time market – leaving the CAISO with less available 5-minute dispatchable supply and having to rely more heavily on pre-dispatched inter-ties and regulation to manage real-time imbalances. This risk is most significant if the price divergence shown in Figure 2.26 is persistent within a multi-day peak load period or predictable across peak load periods.

Figure 2.26 Average Hourly Prices and Quantities for Pre-dispatch Imports and 5-Minute Real Time Dispatch – Hours 12 - 18 for July 10 through August 4, 2006



Ancillary Service Markets

Though the CAISO Real Time Market prices are not well correlated with daily bilateral prices during extreme peak periods, the CAISO Ancillary Service Market prices are (Figure 2.27).

Figure 2.27 Day Ahead Upward Ancillary Service Average Price and Hourly Spot Bilateral Price for July 10 – August 3, 2006

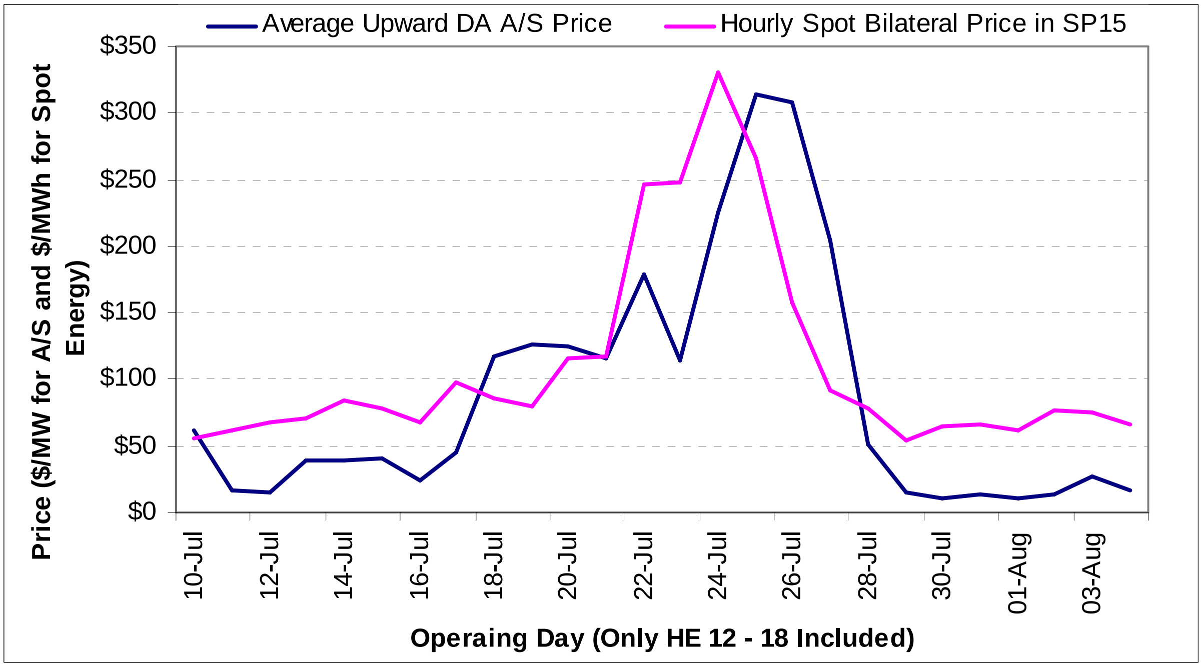
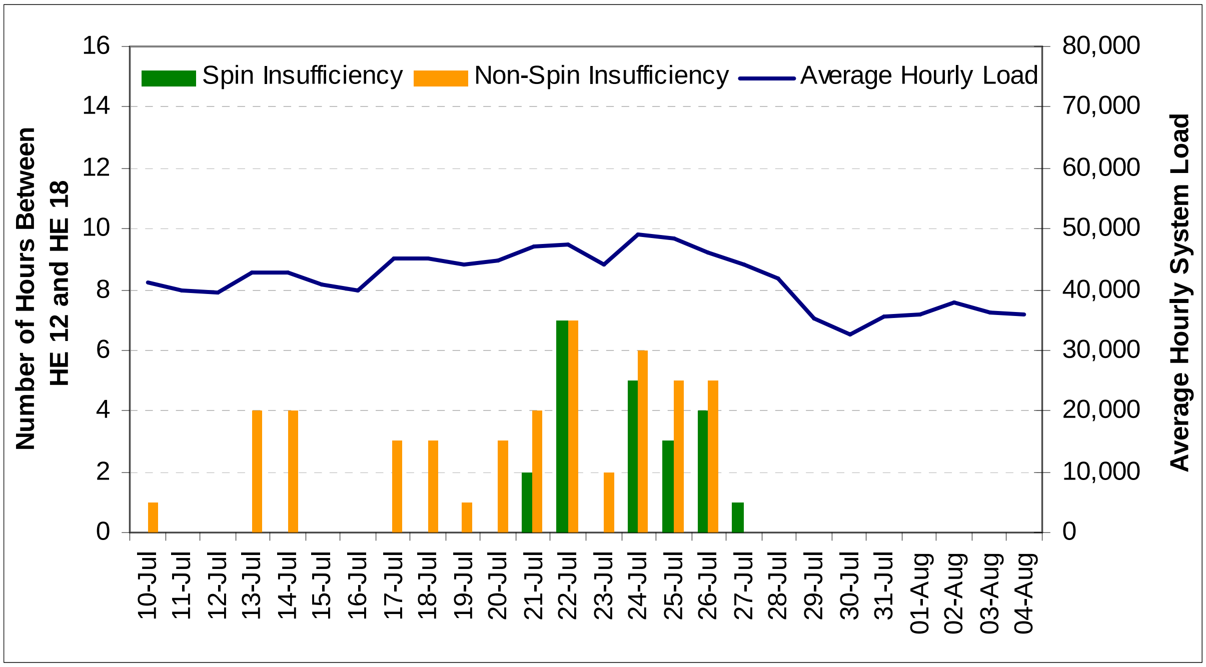


Figure 2.27 shows that the average price of upward Ancillary Services (Regulation-Up, Spinning Reserve, and Non-Spinning Reserve) purchased in the day-ahead market clearly reflect (a) the opportunity cost of offering the generation capacity as reserve as opposed to selling the energy in the bilateral market or (b) the expectation of being held down as reserve through the operating hour when real-time prices are reflective of day-ahead bilateral prices (i.e., the opportunity cost of foregoing real-time market prices).

Despite the higher prices for upward Ancillary Services, the CAISO did experience significant procurement shortages across the peak load days from July 21 - 26, as seen in Figure 2.28. Both Spinning Reserve and Non-spinning Reserve experienced high levels of procurement shortages across the super-peak hours of HE 12 - 18.

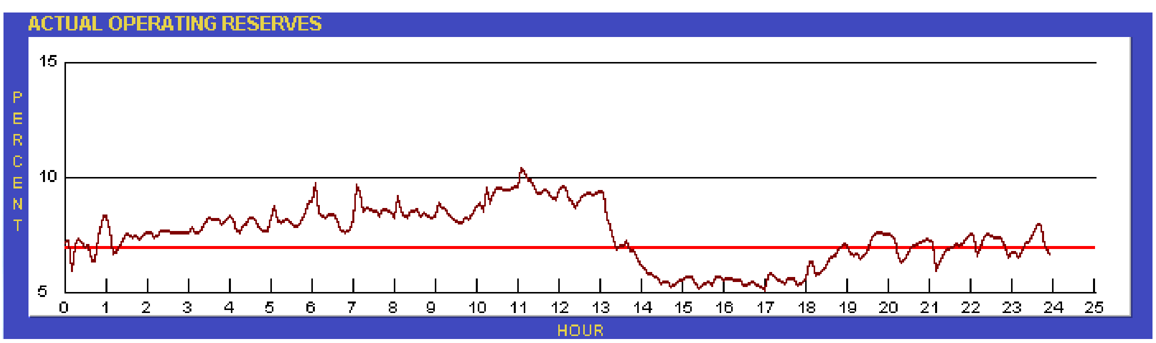
Figure 2.28 Ancillary Service Bid Insufficiency (Hours 12-18)



The Hour Ahead and Day Ahead Markets are the only two markets in which the CAISO can procure operating reserves. Under extreme conditions, RMR units can also be committed to provide reserves. On July 24, the CAISO was deficient in Spinning Reserve during six hours across the super-peak and deficient in Non-spinning Reserve during five hours across the super-peak with no additional opportunity after the close of the Hour Ahead Market to procure additional operating reserves.

As load ramped up toward the super-peak period of the day on July 24, the CAISO had less operating reserve due to bid and procurement insufficiency, and operating reserves dipped below the 7 percent level during HE 14. The CAISO declared a Stage 2 Emergency at the beginning of HE 14 when actual operating reserves began a steep decline towards the 5 percent level, as seen in Figure 2.29.

Figure 2.29 Actual Operating Reserve Levels for July 24, 2006 (taken from OASIS)



During the Stage 2 Emergency, the actual imbalance requirements were minimal and there were additional un-dispatched energy bids in the imbalance stack. However, there is no mechanism in the current market design to take those un-dispatched energy bids and convert them to operating reserve to be held in the event of a contingency. After declaring a Stage 2 Emergency and observing actual operating reserves drop to near 5 percent, the CAISO called on 855 MW of interruptible load at 14:37 to reduce load levels and keep reserves from declining below 5 percent.

As a result of ancillary service bid insufficiency and a market that does not accommodate obtaining additional operating reserve in real time, the CAISO was in a Stage 2 Emergency and calling for interruptible load curtailment while there were unused bids in the imbalance energy stack and moderate imbalance prices primarily in the $55 to $100 range with a few intervals pricing near $400/MWh. This situation reflects two deficiencies in the current Real Time Market design: 1) an inability to procure operating reserve in real-time and 2) a lack of a reserve shortage scarcity pricing mechanism. If the CAISO had a real-time market for operating reserve and a reserve shortage scarcity pricing mechanism, the price of real-time operating reserve could better reflect the value of reserve (given the shortage situation) and energy prices would as well – provided the energy dispatch is co-optimized with operating reserve procurement. In which case, real-time prices (energy and reserves) would be likely at or near the $400 bid cap. Some Eastern ISOs (e.g., NY ISO) have successfully incorporated these kinds of mechanisms into their real-time market design. The current release of MRTU (Release 1) will include a real-time market for operating reserves but it will not include a reserve shortage scarcity pricing mechanism; thus, MRTU would partially solve the design deficiency by being able to procure reserves in real-time but this in itself will not guarantee that reserve prices will properly reflect scarcity conditions. Pursuant to the September 21, 2006 FERC Order on MRTU, the CAISO has been directed to develop and implement a reserve shortage scarcity pricing mechanism within 12 months after implementation of MRTU.

2.4 Total Wholesale Energy and Ancillary Services Costs

Since 1999, the DMM has reported its estimate of annual wholesale energy costs. This provides an estimate of total wholesale market costs to load served that can be compared across years. It includes estimates of utility retained generation costs, forward bilateral contract costs, real-time energy costs, and ancillary service reserve costs. This index has been updated in this report for operating years 2002-2006 to include reliability costs (must-offer minimum-load compensation, out-of-sequence redispatch premiums, and fixed and variable RMR costs) with the real-time component. The estimated total wholesale energy cost for 2006 was approximately $11.4 billion, compared to $13.6 billion in 2005. It is important to note that these cost estimates are not just reflecting 2006 spot market prices but are based on a combination of estimated spot market transactions, costs of long-term contracts signed during the energy crisis, an estimate of the production cost of utility owned generation, and other cost components – all of which are described in the accompanying notes to Table 2.7. The decrease can be attributed to the closure of the Mohave coal-fired generation facilities and substantially lower natural gas prices in 2006. Table 2.7 shows Estimated Wholesale Energy Costs by month for 2006, and annual summaries from 1998 through 2005. The reliability costs are itemized individually in a section below that details average wholesale energy costs per unit of load.

Table 2.7 Monthly Wholesale Energy Costs: 2006 and Previous Years

Month	ISO Load (GWh)	Total Est. Forward Costs ($MM)	RT and Reliability Costs ($MM)	AS Costs ($MM)	Total Costs of Energy ($MM)	Total Costs of Energy and A/S ($MM)	Avg Cost of Energy ($/MWh load)	Avg Cost of A/S ($/MWh load)	A/S as % of Wholesale Cost	Avg Cost of Energy & A/S ($/MWh load)
Jan-06	18,922	$ 831	$ 69	$ 17	$ 900	$ 917	$ 47.54	$ 0.91	1.9%	$ 48.45
Feb-06	17,054	$ 724	$ 48	$ 13	$ 771	$ 785	$ 45.24	$ 0.78	1.7%	$ 46.02
Mar-06	18,814	$ 746	$ 58	$ 14	$ 804	$ 818	$ 42.71	$ 0.75	1.7%	$ 43.46
Apr-06	17,581	$ 713	$ 91	$ 23	$ 804	$ 827	$ 45.73	$ 1.29	2.7%	$ 47.02
May-06	19,635	$ 766	$ 58	$ 22	$ 824	$ 846	$ 41.96	$ 1.11	2.6%	$ 43.07
Jun-06	21,918	$ 918	$ 65	$ 22	$ 983	$ 1,005	$ 44.86	$ 1.01	2.2%	$ 45.88
Jul-06	25,559	$ 1,378	$ 61	$ 66	$ 1,439	$ 1,505	$ 56.30	$ 2.57	4.4%	$ 58.88
Aug-06	22,891	$ 1,085	$ 29	$ 17	$ 1,114	$ 1,131	$ 48.67	$ 0.73	1.5%	$ 49.40
Sep-06	20,908	$ 847	$ 31	$ 12	$ 878	$ 890	$ 42.00	$ 0.55	1.3%	$ 42.55
Oct-06	19,183	$ 788	$ 37	$ 8	$ 825	$ 833	$ 42.99	$ 0.43	1.0%	$ 43.42
Nov-06	18,365	$ 857	$ 35	$ 10	$ 893	$ 903	$ 48.61	$ 0.54	1.1%	$ 49.15
Dec-06	19,432	$ 901	$ 51	$ 10	$ 952	$ 962	$ 48.99	$ 0.50	1.0%	$ 49.49
Total 2006	**240,260**	**$ 10,553**	**$ 633**	**$ 234**	**$11,186**	**$ 11,420**	**$ 46.56**	**$ 0.97**	**2.0%**	**$ 47.53**
Total 2005	236,449	$ 12,526	$ 830	$ 228	$13,356	$ 13,584	$ 56.49	$ 0.96	1.7%	$ 57.45
Total 2004	239,788	$ 11,832	$ 1,099	$ 184	$12,931	$ 13,115	$ 53.93	$ 0.77	1.4%	$ 54.70
Total 2003	230,668	$ 10,814	$ 696	$ 199	$11,510	$ 11,709	$ 49.90	$ 0.86	1.7%	$ 50.76
Total 2002	232,011	$ 9,865	$ 532	$ 157	$10,397	$ 10,554	$ 44.81	$ 0.68	1.5%	$ 45.49
Total 2001	227,024	$ 21,248	$ 4,586	$ 1,346	$25,834	$ 27,180	$ 113.79	$ 5.93	5.0%	$ 119.72
Total 2000	237,543	$ 22,890	$ 3,446	$ 1,720	$26,336	$ 28,056	$ 110.87	$ 7.24	6.1%	$ 118.11
Total 1999	227,533	$ 6,848	$ 562	$ 404	$ 7,410	$ 7,814	$ 32.57	$ 1.78	5.2%	$ 34.34
1998 (9mo)	169,239	$ 4,704	$ 1,061	$ 638	$ 5,765	$ 6,403	$ 34.07	$ 3.77	10.0%	$ 37.83

Notes to Wholesale Costs Table:

CAISO load is total energy consumed in GWh. Cost totals are in millions of dollars. Averages are in dollars per MWh of load served.

1998-2000:

Forward costs include estimated California Power Exchange (PX) and bilateral energy costs.

Estimated PX Energy Costs include UDC owned supply sold in the PX, valued at PX prices.

Estimated Bilateral Energy Cost based on the difference between hour-ahead schedules and PX quantities, valued at PX prices.

Beginning November 2000, CAISO Real-time Energy Costs include OOM Costs.

1998-2001:

RMR costs were not available and are not included. Must-Offer costs were not applicable.

2001 and 2002:

Sum of hour-ahead scheduled costs. Includes UDC (cost of production), estimated and/or actual CDWR costs, and other bilaterals priced at hub prices.

RT energy includes OOS, OOM, dispatched real-time paid MCP, and dispatched real-time paid as-bid.

2002 through 2006:

RT and reliability costs include real-time incremental balancing costs, decremental balancing savings, minimum-load compensation costs for resources committed per Must Offer Obligation, OOS/OOM costs, RMR fixed and variable costs.

2003:

Loads are unadjusted. CAISO included SMUD through 6/18/02. Load Jan-03 through Jun-03 may be lower than in 2002 due to SMUD exit.

2003 through 2006:

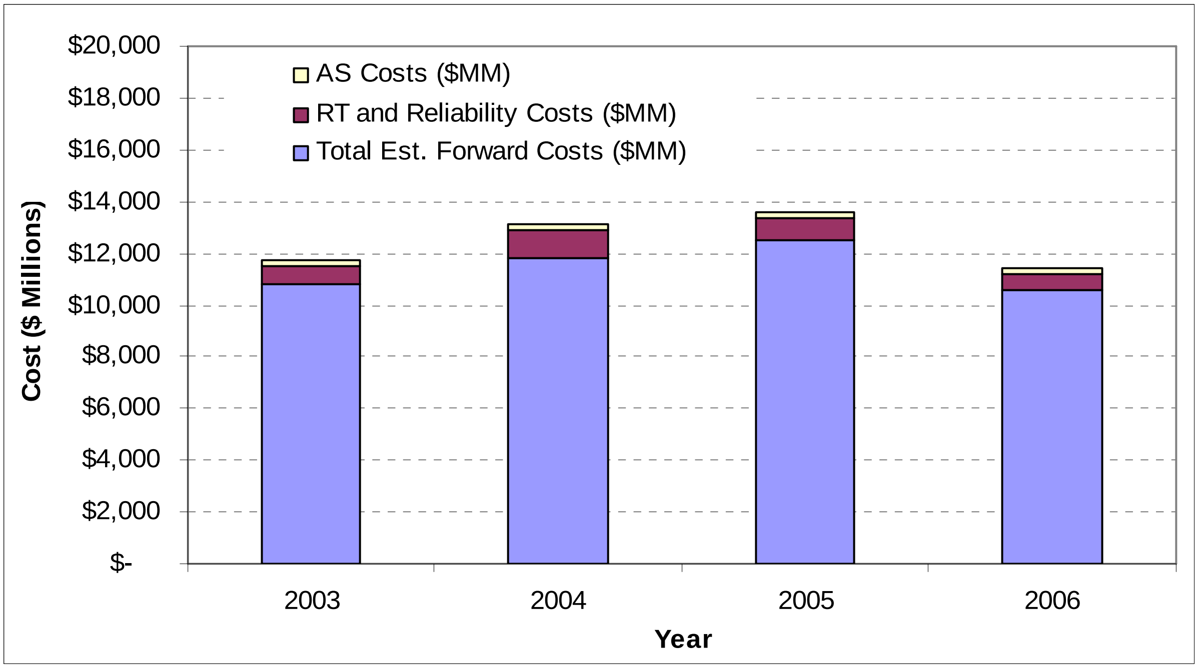
Forward energy costs revised slightly upward using a new methodology to include: utility-retained generation at estimated production costs, long-term contract (formerly managed by CDWR/CERS) estimated using 2002 delivery volumes; and short-term bilateral procurement estimated at utility-supplied procurement prices, when available, or Powerdex hour-ahead prices.

All years:

A/S costs include CAISO purchased and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund, if any.

Figure 2.30 indicates that total annual wholesale energy costs increased between 2003 and 2005, and then declined in 2006. This largely follows the trend in the price of natural gas, which increased steadily between 2002 and 2005 from approximately $3 to $14/mmBtu by late 2005, and then decreased to the range of $6 to $8/mmBtu in 2006. Another factor that contributed to the decrease was the decommissioning of the coal-fired Mohave Power Project on January 1, 2006, which resulted in savings due in part to the resultant decrease in emission permit requirements.[10]

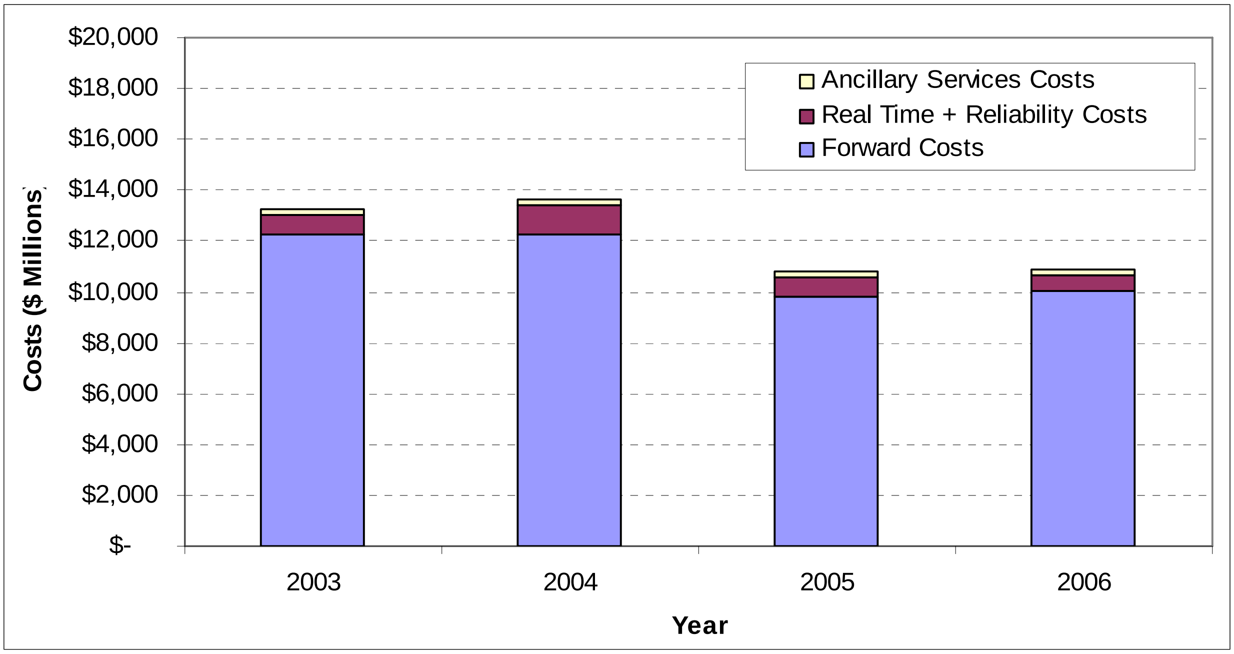
Figure 2.30 Total Wholesale Costs: 2003-2006



As noted previously, the key factor driving the trend in wholesale energy costs has been the cost of natural gas. To control for this largely exogenous factor, the DMM also estimates wholesale costs normalized against changes in the price of natural gas. As seen in Figure 2.31, the normalized cost of energy declined by approximately 19.6 percent between 2004 and 2005, and then was nearly unchanged between 2005 and 2006.

[10] Calculation based upon assumptions. Actual emission permit costs are not known.

Figure 2.31 Total Wholesale Costs Normalized to Fixed Gas Price: 2003-2006[11]



A component breakdown of contributing factors to energy costs serves as a useful benchmark of CAISO and restructured market performance. Table 2.8 shows the average contribution to the cost per megawatt-hour of wholesale energy between 2002 and 2006. Note in particular that the Grid Management Charge (GMC), essentially the cost of CAISO operations on a per-megawatt-hour basis, has decreased approximately 28 percent since 2003.

[11] July 2004 gas price ($5.70/mmBtu) used as standard. Annual energy costs in 1998 and 1999 were normalized by dividing the ratio of annual average gas prices and the July 2004 average gas price ($5.70/mmBtu) and adding this adjusted annual energy cost to the non-energy cost components. For the 2000 to 2006 period, energy costs were normalized separately for each month by dividing the monthly nominal energy costs by the ratio of the applicable monthly gas price and the July 2004 indexed gas price and then adding the non-energy cost components. Total costs include all actual or estimated energy costs adjusted for differences in natural gas price along with unadjusted costs of grid management, ancillary services, and fixed RMR payments.

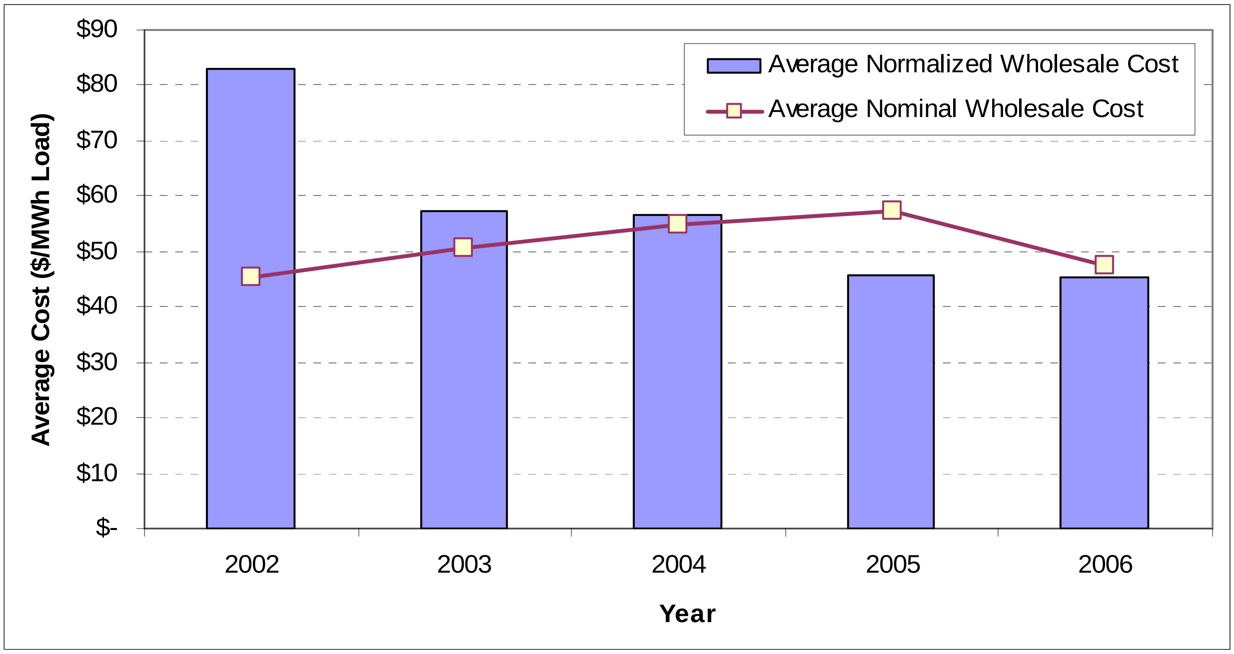
Table 2.8 Contributions to Estimated Average Wholesale Energy Costs, 2002-2006[12]

	2002	2003	2004	2005	2006	Change '05-'06
Forward-Scheduled Energy Costs, excl. Interzonal Congestion and GMC	$ 40.92	$ 45.77	$ 48.21	$ 52.28	$ 42.99	$ (9.29)
Interzonal Congestion Costs	$ 0.18	$ 0.12	$ 0.23	$ 0.23	$ 0.23	$ 0.00
GMC	$ 1.00	$ 1.00	$ 0.90	$ 0.84	$ 0.72	$ (0.12)
Incremental In-Sequence RT Energy Costs	$ 0.49	$ 0.63	$ 0.86	$ 1.55	$ 1.01	$ (0.54)
Explicit MLCC Costs (Uplift)	$ 0.26	$ 0.54	$ 1.21	$ 0.55	$ 0.56	$ 0.01
Out-of-Sequence RT Energy Redispatch Premium	$ 0.02	$ 0.19	$ 0.43	$ 0.14	$ 0.10	$ (0.04)
RMR Net Costs (Include adjustments from prior periods)	$ 1.60	$ 1.95	$ 2.67	$ 2.14	$ 1.78	$ (0.37)
Less In-Sequence Decremental RT Energy Savings	$ (0.08)	$ (0.29)	$ (0.59)	$ (0.87)	$ (0.81)	$ 0.06
Average Total Energy Costs	**$ 44.39**	**$ 49.90**	**$ 53.93**	**$ 56.86**	**$ 46.58**	**$ (10.28)**
A/S Costs (Self-Provided A/S valued at ISO Market Prices)	$ 0.68	$ 0.86	$ 0.77	$ 0.96	$ 0.97	$ 0.01
Average Total Costs of Energy and A/S	**$ 45.07**	**$ 50.76**	**$ 54.70**	**$ 57.83**	**$ 47.55**	**$ (10.27)**

Figure 2.32 shows the average total annual wholesale cost of energy and ancillary services ($/(MWh of Load)) for 2002 through 2006, expressed in both nominal terms and normalized for changes in natural gas prices. This nominal average cost increased in 2002 through 2005 mainly due to increasing gas prices but declined sharply in 2006 as gas prices declined. In contrast, the gas-normalized average cost has declined steadily over 2002 through 2005 as long-term contracts signed during the energy crisis have expired and efficient combined-cycle generation has entered service in California and neighboring areas. The gas-normalized average cost in 2006 was approximately the same as in 2005.

[12] 2005 figures are updated to reflect the most current data available. Inter-zonal congestion costs are included in other tables and charts in this section as part of the cost of forward energy. This is based on the assumption that forward costs known to DMM are either sourced within NP15 or SP26, or are priced including delivery to those locations. GMC is also included as part of the cost of forward energy under the assumption that it is paid for by supply as a cost of serving load.

Figure 2.32 Average Total Wholesale Costs per Unit of Load, 2002-2006



2.5 Market Competitiveness Indices

2.5.1 Residual Supplier Index for Total Energy Purchases

The Residual Supplier Index (RSI) measures the market structure rather than market outcomes. This index measures the degree to which suppliers are pivotal in setting market prices. Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. Mathematically, RSI values are calculated for each hour (*i*) based on the following formula:

$$RSI_i = \frac{TS_i - LSS_i}{TD_i}$$

Where,

TS_i = Total Supply in hour *i*

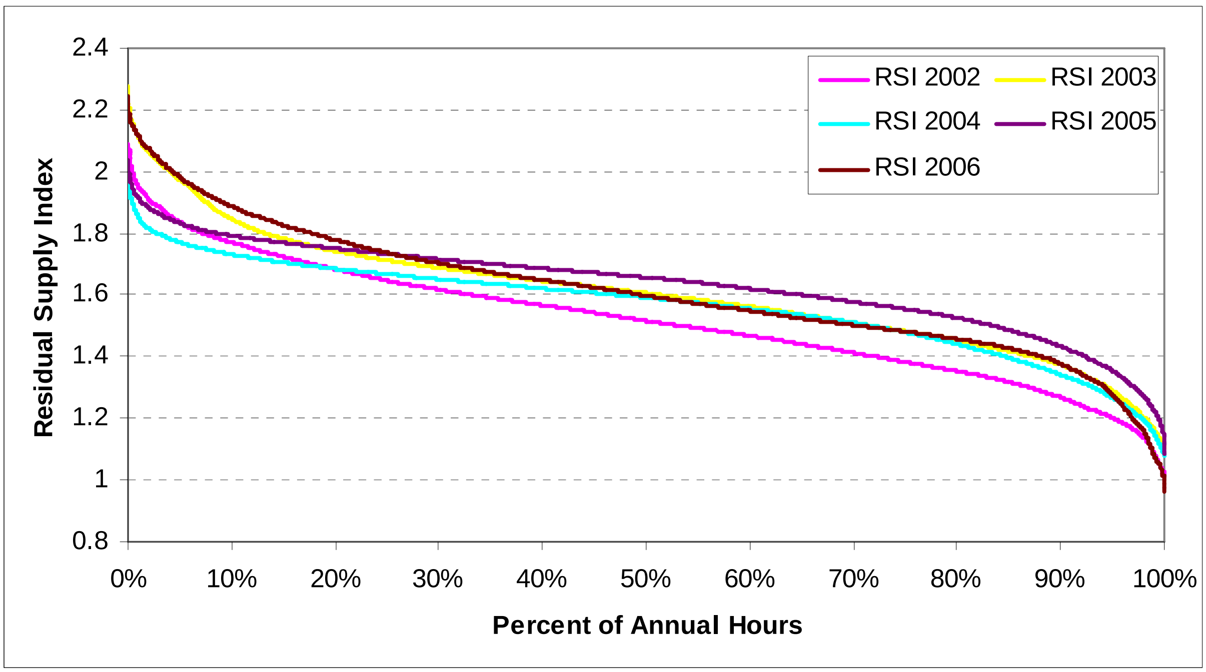
LSS_i = Supply of Largest Single Supplier in hour *i*

TD_i = Total Demand in hour *i*

The largest supplier is pivotal if the total demand cannot be met absent the supplier's capacity. Such a case would result in an RSI value less than 1. When the largest suppliers are pivotal (an RSI value less than 1), they are capable of exercising market power. In general, higher RSI values indicate greater market competitiveness.

The RSI levels in 2006 were generally among the highest of the past eight years. On the RSI duration curve in Figure 2.33, more than 25 percent of the time in 2006 we experienced the highest RSI values for the last eight years. On the lower end, in 2006 there were about 130 hours or 1.31 percent when the RSI level dropped below 1.1.[13] This value was marginally higher in 2006 than in 2003-2005, when it ranged from 22 to 48 hours. However, it was much lower than 2001 when there were 3,215 hours or 37 percent of the hours where the RSI was less than 1.1. The RSI in 2000 was below 1.1 for approximately 20 percent of hours. The RSI values are consistent with the market outcomes and short-term energy market price-cost mark-ups observed in 2006. The significant amount of long-term contracts entered into since 2001 have also led to more competitive market outcomes, although the impacts of contracting are not accounted for in this analysis as it is directed at reflecting the physical aspects of the market. The RSI analysis shows that the underlying physical infrastructure was much more favorable for competitive market outcomes in the period 2002 through 2006 than 2001 as reflected by the higher RSI values. Figure 2.33 compares RSI duration curves for the past five years.

Figure 2.33 Residual Supply Index (2001-2006)



2.5.2 Price-to-Cost Mark-up for Short Term Energy Purchases[14]

Another index used to measure market performance in the California wholesale electricity markets is the price-to-cost mark-up. This is the difference between the actual price paid in the market for wholesale electricity and an estimate of the production cost of the most expensive, or marginal, unit of energy needed to serve load. The ratio of the volume-weighted average mark-up to marginal cost is a metric that can be used to identify market performance trends over time.

[13] Historically, market power can be prevalent with an RSI of 1.1 due to estimation error and the potential for tacit collusion among suppliers.

[14] Short-term energy is defined as forward purchased energy purchased within 24 hours of real-time operation.

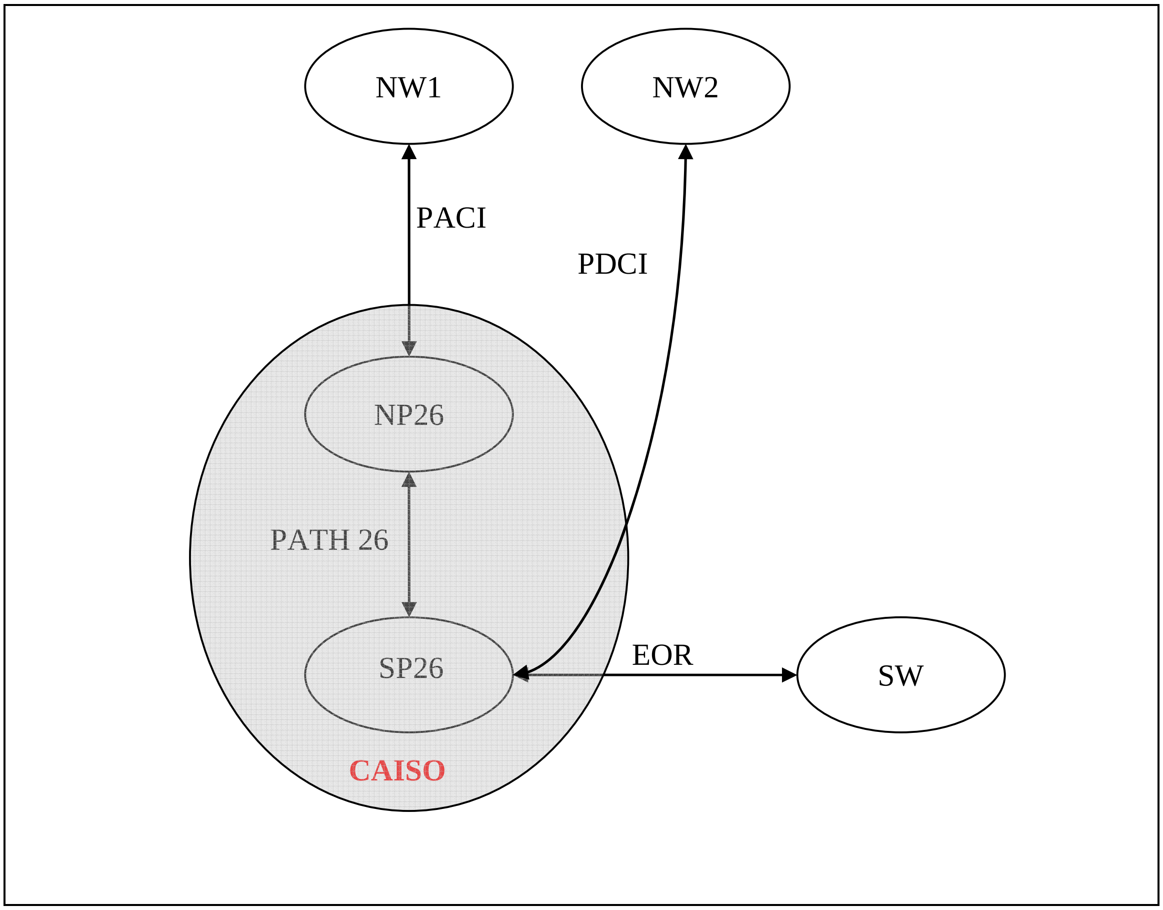
Previous Annual Reports have implemented several index constructs yielding measures of market competitiveness in the short-term energy markets. Those indices have been based on several price sources ranging from CAISO market data and information from bilateral forward contracts to prices from the Department of Water Resources' California Energy Resources Scheduler (CERS) energy procurement deals. The methodology has been updated to include data sources that were previously not available. However, there are still periods in calendar year 2004 for which short-term energy procurement information is not available. During these periods, hourly short-term forward price data purchased from Powerdex is used as a substitute. For 2006, the actual short-term prices paid were obtained from confidential bilateral transactions data of three major IOUs in the CAISO markets (PG&E, SCE and SDGE). Only the transactions that occurred 24 hours prior to the operating day were considered in the analysis to be short-term.

The simulation of competitive benchmark prices considers a single-price auction framework and clears offers against hour-ahead scheduled load subject to the following assumptions:

- Simplified five node four line zonal model.
- Import and export bids are fixed in quantity at observed hour-ahead scheduled import levels and priced at the regional spot trading hub reported price reported from Powerdex with the California-Oregon Border (COB) as Northwest and Palo Verde (PV) as Southwest.
- Internal thermal generators with heat rate data bid in at cost as determined by their incremental heat rate, hourly natural gas price and variable operating and maintenance costs.
- Internal hydroelectric units, nuclear units and the rest of thermal units without heat rate data bid in zero as price and hour-ahead schedule as quantity.
- All the rest internal generators, including biomass, geothermal, Qualified Facility, wind, etc., bid in zero as price and metered output as quantity.
- Unit commitment decisions are based on historical hour-ahead schedules and metered output.

Figure 2.34 shows the simplified zonal radial network model used in the simulation.

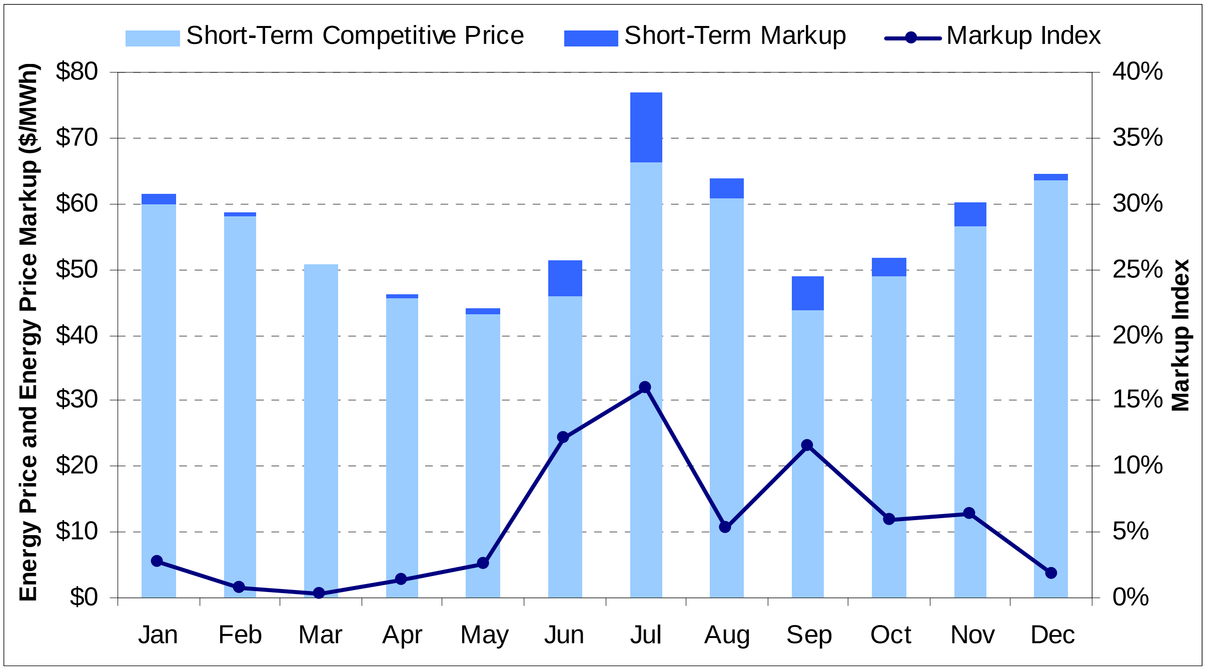
Figure 2.34 Simplified Network Topology Used in Competitive Price Simulation



The CAISO market model utilizes PLEXOS for Power Systems as the market simulation tool. PLEXOS employs a linear programming based production cost minimization model, which allows for co-optimization with ancillary service markets.

For calendar year 2006, the CAISO observed monthly short-term mark-ups ranging from 1 to 16 percent, compared to 4 to 16 percent in the prior year. Figure 2.35 summarizes competitiveness in the short-term forward energy markets. There were only three months when mark-ups were greater than 10 percent. Months with the greatest mark-ups were June, July and September, corresponding to the summer high demand period. On the other hand, due to abundant hydroelectric generation imports from the Northwest in the winter and spring months, the first five months of the year experienced very low mark-ups of less than 3 percent. On the whole, 2006 short-term forward markets functioned effectively, leading largely to competitive pricing in the CAISO Control Area.

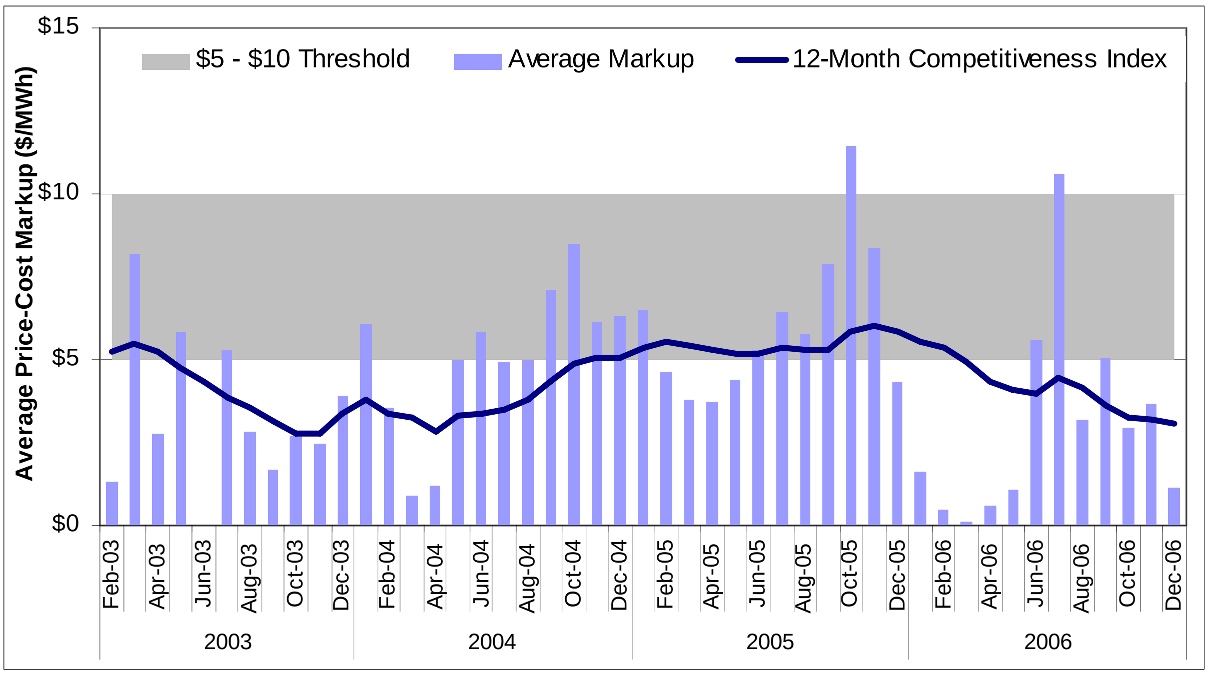
Figure 2.35 2006 Short-term Forward Market Index



2.5.3 Twelve-Month Competitiveness Index

The CAISO employs several indices to assess market competitiveness. The index in Figure 2.36 serves to measure market outcomes over extended time periods against estimated perfectly competitive market outcomes. The 12-Month Competitiveness Index is a rolling average of the short-term energy mark-up above simulated competitive prices during a twelve month period. The CAISO assumes that the short-term energy market is subject to little or no exercise of market power when the index is near or below a $5 to $10 per MWh range. The index decreased overall compared to 2005 mainly due to low mark-ups during the winter and spring months and relatively mild conditions during the summer and fall – with the exception of July.

Figure 2.36 Twelve-Month Competitiveness Index



2.5.4 Price to Cost Mark-up for Imbalance Energy

The real-time price-to-cost mark-up index is designed to measure real-time imbalance market performance. This index detects trends in the price-to-cost ratio. Sporadic price spikes due to operational constraints such as shortage of ramping capability have limited impact on this real-time mark-up. This index is a somewhat conservative measure of a competitive baseline price since it only takes into account generation units that were dispatched by the CAISO. By only including dispatched units in determining the competitive baseline price, this metric does not account for any possible economic withholding of units that bid higher than the market clearing price. This methodology assumes that high-priced bids above the market clearing price correspond to high costs which will usually produce a higher estimated competitive baseline price (and lower mark-up). The methodology also discounts physical withholding by assuming that units that are forced out of service are not available for legitimate reasons and that generators that do not bid in all of their available capacity will have that capacity bid in for them by the CAISO under the must-offer obligation.

Figure 2.37 and Figure 2.38 show the monthly average mark-up for incremental and decremental real-time energy dispatched in 2006, respectively. As shown in these figures, the incremental Real Time Market mark-ups are above 30 percent for almost all of the first seven months. The mark-ups are particularly high during the March to June period, at more than 50 percent.

It is important to note that this market is prone to some degree of market power because of the very low volumes that clear this market and the fact that demand for 5-minute energy is very volatile and price inelastic. A generator submitting a bid at a very high price for the last few megawatt-hours of its unit's capacity will likely have those bids taken periodically, as the total supply of bids in this market can be very thin, thus requiring periodic dispatching of most or all of the available energy. The low volume and highly volatile nature of this market make it unattractive for new supply to enter to "compete away" high energy prices. It is also important to note that the impact of market power in the Real Time Market is relatively minor given the low market volumes and the fact that some of the generation earning the high market prices is owned or under operational control of load-serving entities. Additional factors that may have contributed to the increase in Real Time Market mark-ups include:

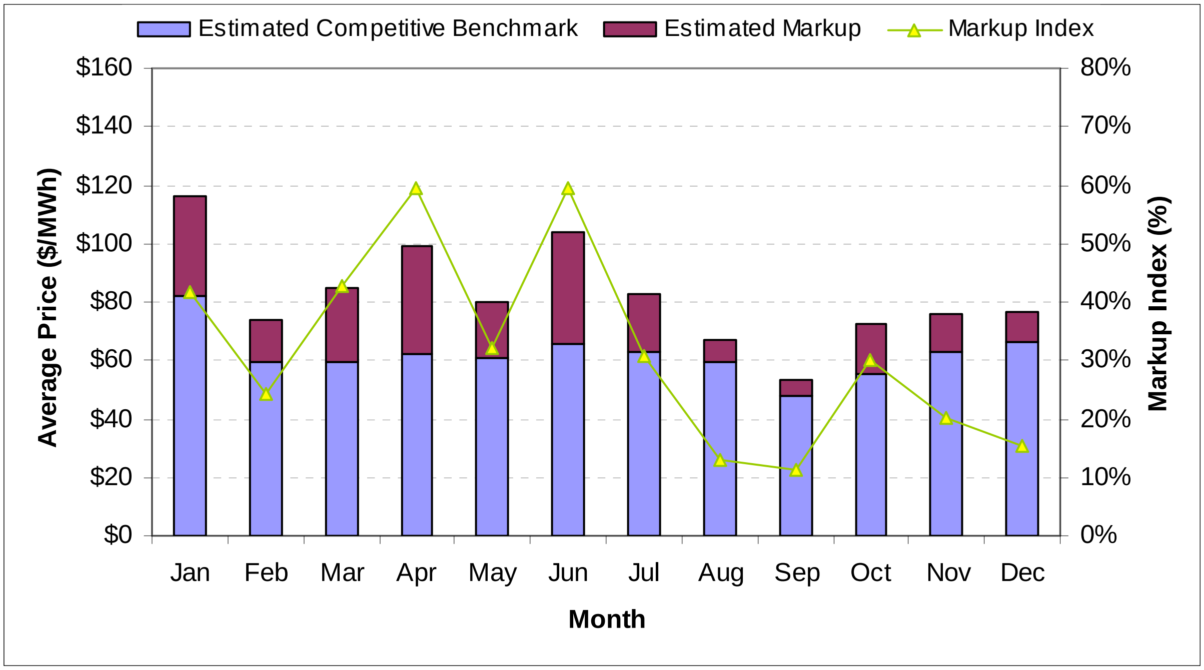
- Price spikes are often a result of limited available 5-minute ramping energy during morning or evening load pull periods when the CAISO needs to dispatch increasing amounts of energy in real time to match or catch the load ramp. An abundance of hydro generation in the first half of 2006 decreased the number of thermal generation units that were on-line, which under more normal conditions would have been available for dispatch in the Real Time Market.

- Loop flow conditions in the Western Interconnection resulted, by design, in RTMA's automated pre-dispatch of exports from NP26 to neighboring areas, and internal incremental dispatch, primarily within SP26. With limited resources available on-line, those resources that were available appeared to enjoy some pricing power during ramping periods.

- The soft bid cap changed from $250/MWh to $400/MWh at the beginning of this year. Real Time Market price spikes at or near the $400/MWh bid cap resulted in much higher mark-ups than under a $250/MWh bid cap.

- The Automated Mitigation Procedure was not always triggered to mitigate the bids when it should have been due to its limited ability to predict high prices in advance of the market. Please refer to section 2.7.2 for further discussions on this point.

Figure 2.37 Real-time Incremental Energy Mark-up above Competitive Baseline Price

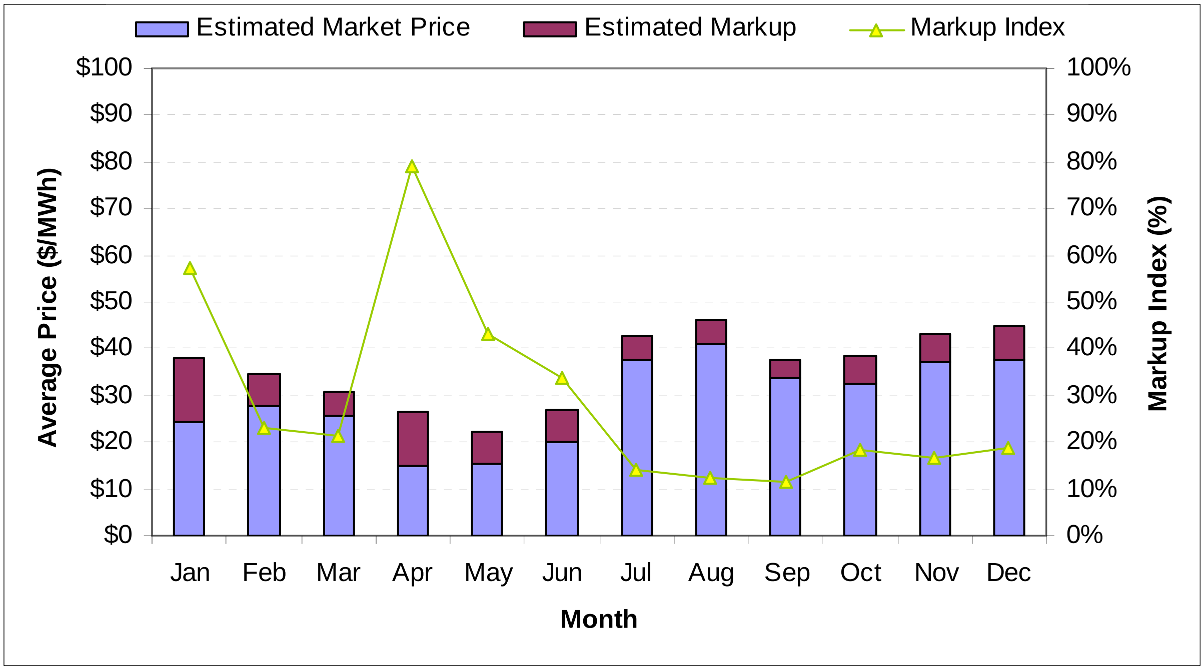


April and June featured the highest monthly incremental mark-ups; mark-ups reached approximately 59.5 percent of competitive benchmarks in both of these months. Indeed, five of the top ten incremental mark-up days in 2006 were in April. These were largely during ramping periods in early mornings and late afternoons, during which RTMA would pre-dispatch large volumes of exports to the Pacific Northwest, while incrementing internal generation, to manage loop flow and/or Path 26 transmission constraints. With relatively few internal units online due to limited market opportunities in the presence of abundant hydroelectric power, those units that were online appeared to enjoy some pricing power.

Moreover, incremental volumes were modest, well below those of decremental volumes. On average, the ratios of decremental to incremental volumes were roughly 11 to 4 in April, and 3 to 1 in June. Incremental volumes averaged 461 MW in April and 421 MW in June.

The decremental real-time mark-up seems to reflect seasonal trends. In spring and early summer, it was common to see negative (-$0.01) bids on the decremental side setting prices, reflecting the bids of certain hydro units that were operating under water management constraints. When such bids set the market clearing price, they tend to increase mark-ups in the decremental market. This is the main reason behind the high decremental mark-ups in the first half of 2005 that peaked in April. This is particularly true for 2006 due to the record hydroelectric production during the spring season for both internal hydroelectric generators and Pacific Northwest imports. Another reason for such high mark-ups stems from an unusual and high degree of loop flow mitigation. Unscheduled counter-clockwise loop flows created congestion on Path 26 during spring 2006. These unscheduled flows were due in part to the unusually high hydroelectric production in Northern California and the Pacific Northwest in 2006. Because RTMA does not model loop flow, operators must manually set the Path 26 limit in RTMA below the physical flow capacity of the path when they anticipate loop flow. In doing so, operators have to dispatch decremental energy in real-time if the loop flow does not show up in real time. Starting in July, mark-ups in the decremental market returned to a range under 20 percent.

Figure 2.38 Real-time Decremental Energy Mark-up below Competitive Baseline Price



2.5.5 Residual Supplier Index for Imbalance Energy

The RSI has also been applied to the Real Time Market to measure the competitiveness of both the incremental and decremental sides of the imbalance energy market. The RSI duration curve shows how concentrated supply was in each hour for year 2006. The duration curve provides a picture of how big a factor the largest supplier is in meeting demand. For incremental energy, the demand for the real-time market is the total in-sequence energy dispatched on top of the hour-ahead schedule. The supply capacity is estimated from the RTMA incremental energy bid stack considering the ramping limits. When the market was split between NP15 and SP15 and the CAISO was dispatching incremental energy in both areas, two incremental energy RSIs were calculated and the one with the higher MCP was kept as the RSI for that interval. For decremental energy, the demand for the real-time market is the total in-sequence energy cleared below the hour-ahead schedule. The supply capacity is estimated from the RTMA decremental energy bid stacks considering the ramping limits. The largest supplier is chosen from the fifteen largest Scheduling Coordinators in the market. Due to the fact that the RSI model cannot capture all the complicated operational and technical constraints considered in the RTMA production software, such as specific operating procedures for different areas, the results represent an approximation of the actual available supply recognized by the RTMA software.

Figure 2.39 shows the RSI curves for the CAISO for incremental supply. In 2006, RSI values dipped below 1.1 for 8 percent of the time. Figure 2.40 shows that real-time energy prices usually are negatively correlated with RSI values, since lower RSI values generally reflect tighter supply conditions, thus resulting in higher real-time energy prices.

Figure 2.39 RSI Duration Curve for Incremental Energy

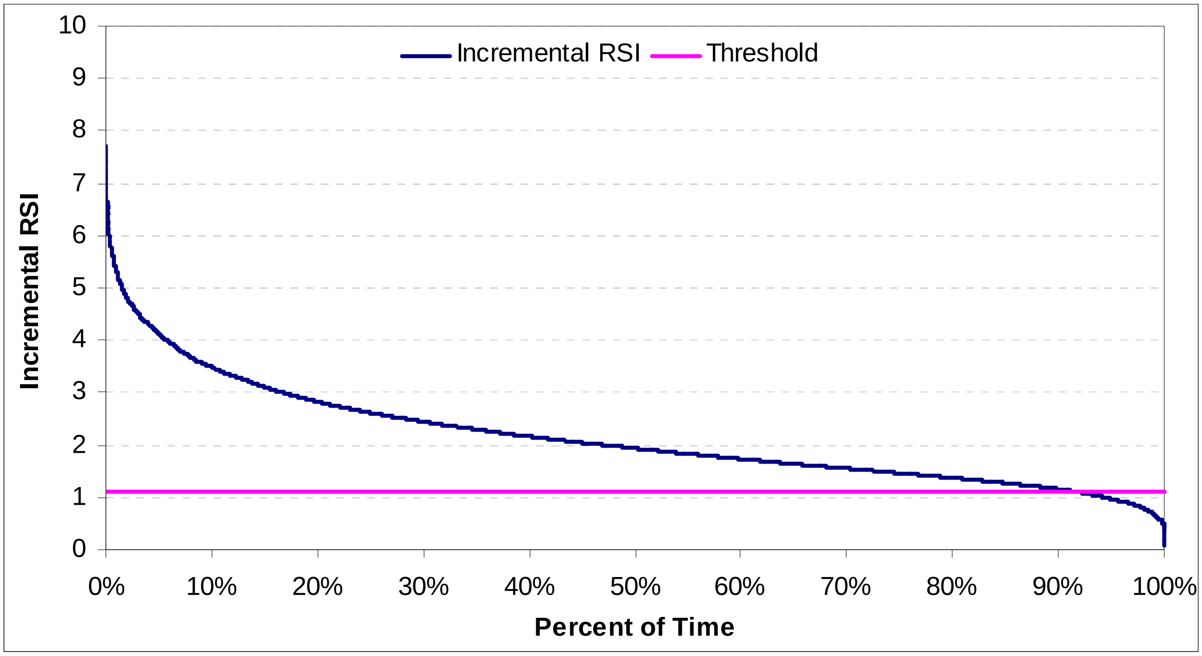


Figure 2.40 RSI Relationship to Real-time Incremental Market Clearing Prices

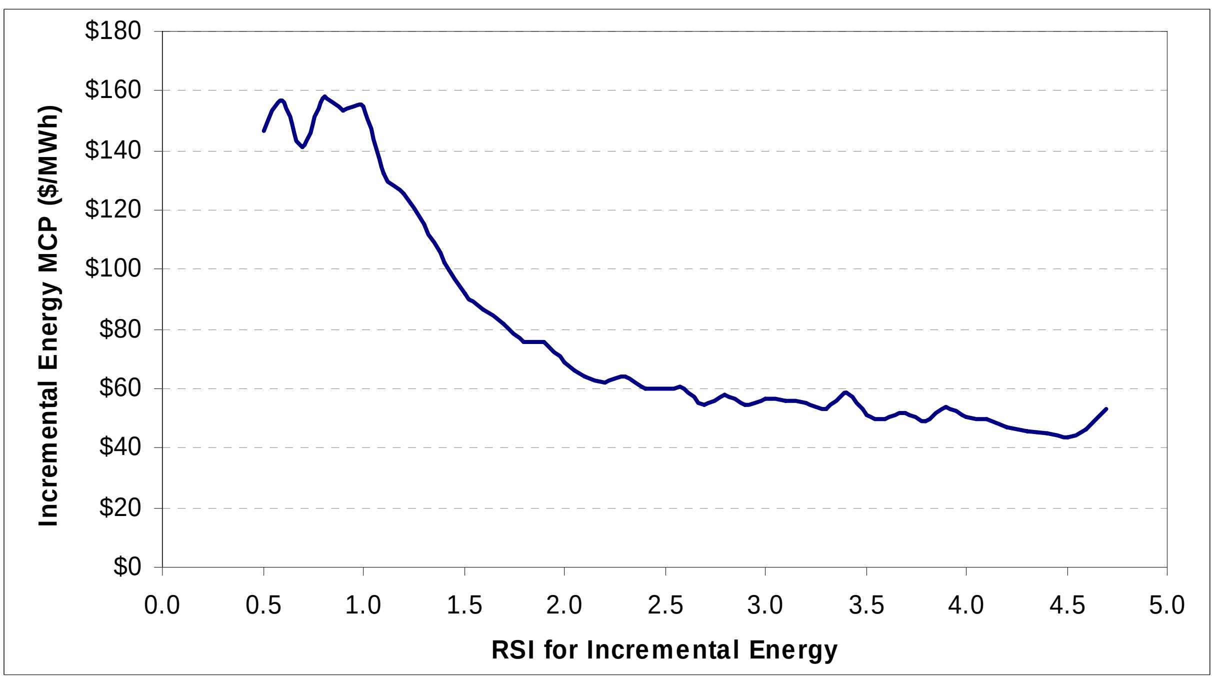


Figure 2.41 shows the RSI duration curve during decremental energy dispatch periods. In 2006, RSI values dipped below 1.1 for 13 percent of the time. RSI values for decremental supply tend to be low in off-peak hours when generators are operating close to their minimum output level and unwilling or unable to offer decremental bids. On average, low RSI values result in low

market clearing prices for those periods when CAISO needs to dispatch decremental energy to balance the market (Figure 2.42).

Figure 2.41 RSI Duration Curve for Decremental Energy

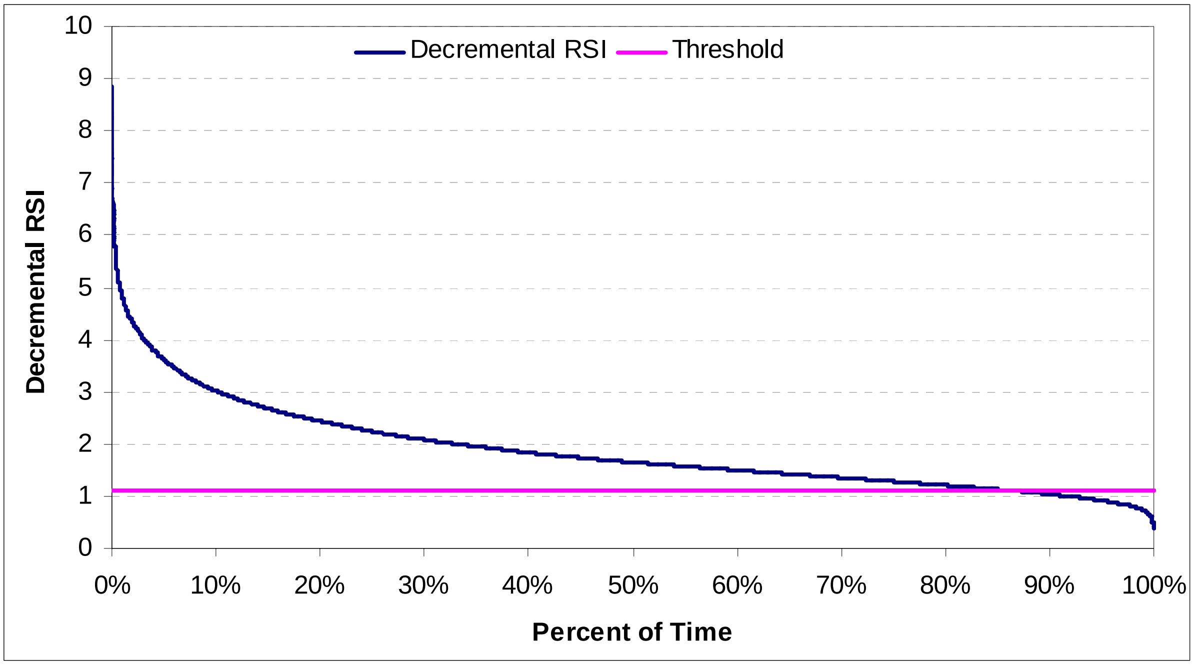
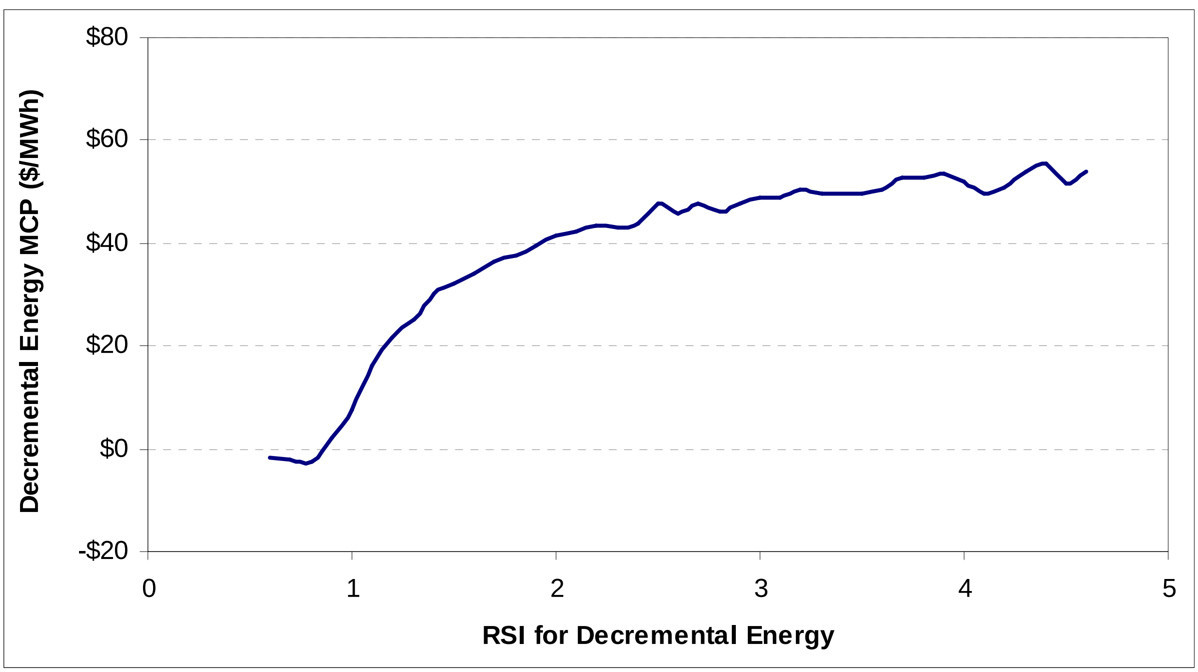


Figure 2.42 RSI Relationship to Real-time Decremental Market Clearing Prices



2.6 Incentives for New Generation Investment

Though California has seen significant levels of new generation investment over the past six years (2001-2006), investment in Southern California has not kept pace with unit retirements and load growth. Moreover, there is a continued reliance on very old and inefficient generation to meet Southern California reliability needs. Going forward, it is imperative that California has an adequate market/regulatory framework for facilitating new investment in the critical areas of the grid where it is needed, particularly Southern California. This section examines some of the issues that possibly affect incentives for new generation investment. It begins with an assessment of the extent to which spot market revenues in 2006 were sufficient to cover the annualized fixed cost of new generation. This is followed by an examination of the use of the must-offer obligation and Resource Adequacy contracts to meet reliability needs in 2006 and the potential impacts that this mechanism may have on incentives for long-term contracting. A review of the generation additions and retirements for 2001 through 2006 and projections for 2007 is provided at the end of this section, along with a review of the continued reliance on older generation facilities.

2.6.1 Revenue Adequacy for New Generation Investment

This section examines the extent to which the current spot markets operated by CAISO provide sufficient revenues to cover the annualized fixed costs of two types of generating units (combined cycle and combustion turbine). It is important to note that spot markets are inherently volatile and as such never guarantee fixed cost recovery, particularly if the market is over-supplied. Moreover, given the lead-time needed for new generation investment, current spot market prices may not be the best indicator for new investment. Expectations on future spot market prices – based on expectations of future supply and demand conditions – are likely to be a stronger driver for long-term contracting, which is the primary means for facilitating new investment. To the extent existing units are critical to meeting reliability needs, their annual fixed costs should be recoverable through a combination of long-term bilateral contracts and/or capacity markets and spot market revenues. Nonetheless, examining the extent to which current spot market prices alone can contribute to fixed cost recovery for new investment has proven to be an important market metric that all ISO's measure.

The annualized fixed costs used in this analysis are obtained from a California Energy Commission (CEC) report, which estimates the annualized fixed cost for a new combined cycle unit and a new combustion turbine to be \$90/kW-year and \$78/kW-year, respectively. The specific operating characteristics of the two unit types that these cost estimates are based on are provided in Table 2.9 and Table 2.10. It should be noted that the finance costs shown in these tables do include a rate of return on capital for equity investment.

Table 2.9 Analysis Assumptions: Typical New Combined Cycle Unit

Maximum Capacity	500 MW
Minimum Operating Level	150 MW
Ramp Rate	5 MW
Heat Rates (MMBtu/kWh)	
Maximum Capacity	7,100
Minimum Operating Level	8,200
Financing Costs	$75 /kW-yr
Fixed Annual O&M	$15 /kW-yr
Other Variable O&M	$2.4/MWh
Startup Costs	
Gas Consumption	1,850 MMBtu/start
Fixed Cost Revenue Requirement	**$90/kW-yr**

Table 2.10 Analysis Assumptions: Typical New Combustion Turbine Unit

Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Heat Rates (MBTU/MW)	
Maximum Capacity	9,300
Minimum Operating Level	9,700
Financing Costs	$58 /kW-yr
Fixed Annual O&M	$20 /kW/year
Other Variable O&M	$10.9/MWh
Startup Costs	
Gas Consumption	180 MMBtu
Fixed Cost Revenue Requirement	**$78/kW-yr**

2.6.2 Methodology

To provide a longer-term perspective, the net revenue analysis provided in this year's Annual Report was conducted over a 4-year period (2003-2006). Some improvements were made to the net revenue analysis methodology used in the 2005 Annual Report to provide a better estimate of potential spot market revenues. For consistency, these modifications were applied over the 4-year study period. Consequently, the numbers shown in this report may differ from those shown in the 2005 Annual Report, though the fundamental findings are the same.

The methodology used this year to calculate the net revenues earned by the hypothetical combined cycle described in Table 2.9 is based on the generator's participation in all possible markets: the Real Time Market and Ancillary Services Market operated by CAISO and the day-ahead bilateral energy markets. The specific methods used for the approach are described below.

Combined Cycle – Net Revenue Methodology

The operational and scheduling assumptions used to assess the potential revenues that could be earned by a typical new combined cycle unit are summarized below:

1) An initial operating schedule for day-ahead bilateral energy markets was determined based on the hourly spot market price index published by Powerdex and the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.9. The unit was scheduled up to full output when hourly prices exceed variable operating costs subject to observing the ramping limitations.

2) The initial schedule was modified by applying an algorithm to determine if it would be more economical to shut down the unit during hours when day-ahead prices fall below the variable operating costs. The algorithm compared operating losses during these hours to the cost of shutting down and restarting the unit; if operating losses exceeded these shutdown/startup costs, the unit was scheduled to go off-line over this period. Otherwise, the unit was ramped down to its minimum operating level during hours when its variable costs exceeded day-ahead bilateral energy prices.

3) If the unit was scheduled to stay off-line in the Day Ahead Market, it may be turned on in the Real Time Market operated by CAISO. The scheduling logic was the same as in the Day Ahead Market except that the Real Time Market clearing prices in both NP15 and SP15 were used instead of the Powerdex prices. The unit was scheduled up to full output when hourly real-time prices exceeded variable operating costs while observing the ramping limits.

4) Ancillary Service revenues were calculated by assuming the unit could provide up to 50 MW of spinning reserve each hour if it was committed in either the Day Ahead Market or Real Time Market for the hour and the output was smaller than its max stable level. The spinning reserve service prices were based on actual CAISO Day Ahead Market prices.

5) All startup gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

6) Finally, a combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues by 5 percent.

In last year's analysis, the results for SP15 also included possible Minimum Load Cost Compensation (MLCC) payments. The hours when the generator was committed under must-offer waiver denials were obtained from 2002 data. A more recent empirical study shows that the must-offer waiver denial hours for combined cycle units have reduced dramatically in the last three years.[15] Moreover, when combined cycle units were denied waivers, it was typically due to specific local and zonal reliability reasons and most qualified units were very old. Since our study was focused on incentive for new generation and only revenues from normal competitive market conditions were considered, such uplifts were not included in this year's analysis.

Combustion Turbine – Net Revenue Methodology

The methodology used this year to calculate the net revenues earned by the hypothetical combustion turbine unit described in Table 2.10 was the same as that of last year. It was based on market participation limited to the Real Time Market[16] and Ancillary Services Market. The specific methods used for these approaches are described below.

1) For each hour, it was assumed the unit would operate if the average hourly real-time price exceeded the unit's marginal operating costs. Operating costs were based on daily spot market gas prices, combined with the heat rates and variable O&M cost assumptions listed in Table 2.10. The unit was scheduled up to full output when Real Time Market hourly prices exceeded variable operating costs while observing the ramping limits.

2) The initial schedule was modified by applying an algorithm to determine if it would be more economical to shut down the unit during hours when Real Time Market prices fall below the variable operating costs. The algorithm compared operating losses during these hours to the cost of shutting down and restarting the unit; if operating losses exceeded these shutdown/startup costs, the unit was scheduled to go off-line over this period. Otherwise, the unit was ramped down to its minimum operating level during hours when its variable costs exceeded real-time energy prices.

3) Ancillary service revenues were calculated by assuming the unit could provide up to 80 MW of non-spinning reserve each hour if it was committed during the hour. The non-spinning service prices were based on actual CAISO Day Ahead Market prices.

4) All startup gas costs associated with the simulated operation of the unit were included in the calculation of operating costs.

5) Finally, a combined forced and planned outage rate of 5 percent was simulated by decreasing total annual net operating revenues from real-time energy and non-spinning reserve sales by 5 percent.

[15] For 2003-2006 period, the total must-offer waiver denial hours for the combined cycle units in the CAISO Control Area ranged from 100 to 300.

[16] Real Time Market prices were used for the Combustion Turbine revenue analysis because this is a more likely market for fast-start units. However, the fact that the CAISO Real Time Market prices were often below prevailing day-ahead and day-of spot market prices, particularly during peak summer periods, makes the use of Real Time Market prices a somewhat conservative measure of potential energy market revenues.

2.6.3 Results

As noted in the previous methodology section, given the often significant differences between day-ahead bilateral prices and the CAISO real-time energy prices, particularly when the CAISO is decrementing resources in real-time, this year's revenue analysis includes additional analysis that examines potential net revenues for a hypothetical combined cycle unit if it participated in both energy markets. The above methodologies also assume that the unit could be dispatched based on perfect foresight of market prices in all participated markets, which is not possible in practice. Therefore, the results may overestimate the net revenues and thus, may be considered the upper limits of potential revenues.

The results for a combined cycle unit are summarized in Table 2.11. It shows a relatively increasing trend in the net revenues from 2004 to 2006. The total capacity factor remains relatively constant throughout the evaluation periods while the revenues from the Day Ahead Market increased in recent years, mainly due to higher prices in the short-term bilateral market. However, the estimated net revenues in all years are below the $90/kW-yr annualized cost of the unit – though the estimated net revenues for the SP15 2006 scenario came very close to the $90/kW-yr.

Table 2.12 shows the estimated net revenues that a hypothetical combustion turbine unit would have earned by participating in the CAISO Real Time Market as well as Ancillary Services Market. It shows a relatively stable trend in the net revenues from all years in the study period. Similar to the combined cycle analysis, the estimated revenues for a hypothetical combustion turbine unit fell well short of the $78/kW-yr annualized costs for all years (2003-2006) under all scenarios.

Table 2.11 Financial Analysis of New Combined Cycle Unit (2003–2006)

Components	2003		2004		2005		2006	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	66%	72%	69%	72%	65%	72%	63%	75%
DA Energy Revenue ($/kW - yr)	$233.90	$246.20	$274.80	$272.80	$372.40	$386.30	$319.70	$355.30
RT Energy Revenue ($/kW - yr)	$64.30	$73.20	$48.80	$56.10	$51.30	$63.80	$34.40	$50.00
A/S Revenue ($/kW – yr)	$0.80	$1.10	$0.70	$0.90	$1.40	$1.80	$1.00	$1.10
Operating Cost ($/kW - yr)	$245.10	$258.60	$276.70	$278.50	$363.10	$382.80	$279.50	$321.60
Net Revenue ($/kW – yr)	$53.90	$61.90	$47.60	$51.40	$62.00	$69.10	$75.50	$84.80
4-yr Average ($/kW – yr)	*$59.80*	*$66.80*						

Table 2.12 Financial Analysis of New Combustion Turbine Unit (2003-2006)

Components	2003		2004		2005		2006	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	15%	19%	9%	14%	8%	10%	7%	10%
Energy Revenue ($/kW - yr)	$118.10	$142.40	$72.80	$121.70	$87.50	$107.50	$69.50	$99.80
A/S Revenue ($/kW - yr)	$19.60	$18.20	$14.10	$27.40	$19.30	$18.50	$22.70	$21.70
Operating Cost ($/kW - yr)	$87.30	$108.00	$54.00	$81.60	$63.70	$82.00	$46.00	$68.90
Net Revenue ($/kW - yr)	$50.40	$52.70	$32.80	$67.50	$43.10	$44.10	$46.10	$52.40
4-yr Average ($/kW - yr)	*$43.10*	*$54.20*						

2.6.4 Discussion

The results shown in Table 2.11 and Table 2.12 indicate that net revenues appear to be sufficient to cover a unit's fixed operating and maintenance (O&M) costs on an annual basis. These fixed O&M costs are the fixed costs that a unit owner would be able to avoid incurring if the unit were not operated for the entire year (i.e., mothballed). Note that variable (fuel) costs (including start-up costs) are automatically covered since the simulation nets these costs against revenues to calculate net revenue. Fixed O&M costs, as reported by the CEC, are $15/kW-year for a combined cycle unit and $20/kW-year for a combustion turbine unit. If net revenues are expected to exceed fixed O&M costs, it should be sufficient to keep an existing unit operating from year to year. However, in order to provide an incentive for new generation investment, expected net revenues over a multi-year timeframe would need to exceed the total fixed costs of a unit (e.g., $90/KW-year for a combined cycle unit).

The results above show that total fixed cost recovery, fixed O&M cost plus the cost of capital, was not achieved for either generation technology in any of the four years. In the case of the combustion turbine unit, net revenues were generally well below the total fixed cost estimate of $78/kW-year. The four year average net revenues ranged from $33/kW-yr to $50/kW-yr in the NP15 area and $44/kW-yr to $68/kW-yr in the SP15 area. The four year averages were $43/kW-yr in the NP15 area and $54/kW-yr in the SP15 area. However, as previously noted, basing potential energy market revenues solely on CAISO Real Time Market prices may tend to understate potential revenues given that real-time prices are generally below the day-ahead and day-of market prices. The same result is true for combined cycle units, where the total fixed cost of $90/KW-year is never fully reached, even when all potential revenues are accounted for. However, revenue analysis for combined cycle units does reveal a favorable trend over the past three years (2004-2006) with estimated net revenues increasing in both zones over this period. The increase for 2006 is mainly due to higher short-term bilateral market prices. The annual net revenues ranged from $48/kW-yr to $76/kW-yr in the NP15 area and $61/kW-yr to $85/kW-yr in the SP15 area. The four year averages were $60/kW-yr in the NP15 area and $67/kW-yr in the SP15 area.

Given the need for new generation investment in California, the finding that estimated spot market revenues failed to provide for fixed cost recovery underscores the critical importance of long-term contracting as the primary means for facilitating new generation investment. It also suggests that there are deficiencies in the current spot market design that are limiting market revenue opportunities – although it could be alternatively argued that the spot market design is adequate and sending the right investment signal for the current market year (i.e., the generation level from a market efficiency standpoint was adequate in 2006) but the net revenue earned in 2006 is not indicative of future market revenue opportunities, which is the primary driver for new investment. In any case, future market design features that could provide better price signals and revenue opportunities for new investment include: locational marginal pricing (LMP) for spot market energy, local scarcity pricing during operating reserve deficiency hours, and possibly monthly and annual local capacity markets. The CAISO Market Redesign and Technology Upgrade (MRTU), scheduled for implementation on February 1, 2008, will provide some of these elements (LMP, some degree of scarcity pricing). Other design options (formal reserve shortage scarcity pricing mechanism and/or local capacity markets) should also be seriously considered for future adoption.

In the meantime, local requirements for new generation investment should be addressed through long-term bilateral contracting under the CPUC Resource Adequacy and long-term procurement framework and similar programs for non-CPUC jurisdictional entities. These programs can provide additional revenue for new generation and cover the gap between annualized capital cost and simulated net spot market revenues provided in the previous section.

While a broader range of contracting opportunities are being developed that could provide additional incentives for new generation, the continued reliance on an aging pool of generating units in California remains a concern. The primary concern is that California can not continue indefinitely to rely on the existing pool of aging resources, which tend to be less economically efficient, more environmentally harmful, and less reliable. Table 2.13 shows generation additions and retirements, with a load growth trend figure. The total estimated net change in supply margins through 2007 is 682 MW for SP15, indicating that new generation has only barely outpaced unit retirements and load growth in this region.[17] One of the consequences of this is the continued reliance on older generation facilities.

Table 2.13 Generation Additions and Retirements by Zone

	2001	2002	2003	2004	2005	2006	Projected 2007	Total Through 2007
SP15								
New Generation	639	478	2,247	745	2,376	434	1,348	8,267
Retirements	0	(1,162)	(1,172)	(176)	(450)	(1,320)	0	(4,280)
Forecasted Load Growth*	148	500	510	521	531	542	553	3,305
Net Change	**491**	**(1,184)**	**565**	**48**	**1,395**	**(1,428)**	**795**	**682**
NP26								
New Generation	1,328	2,400	2,583	3	919	199	136	7,568
Retirements	(28)	(8)	(980)	(4)	0	(215)	0	(1,235)
Forecasted Load Growth*	389	397	405	413	422	430	439	2,895
Net Change	**911**	**1,995**	**1,198**	**(414)**	**497**	**(446)**	**(303)**	**3,438**
ISO System								
New Generation	1,967	2,878	4,830	748	3,295	633	1,484	15,835
Retirements	(28)	(1,170)	(2,152)	(180)	(450)	(1,535)	0	(5,515)
Forecasted Load Growth*	537	897	915	934	953	972	991	6,199
Net Change	**1,402**	**811**	**1,763**	**(366)**	**1,892**	**(1,874)**	**493**	**4,121**

There is a large pool of aging units in California, with 46 units built before 1979 having an average age of 43 years as seen in Table 2.14. Figure 2.43 shows the percent of hours in a year that units built before 1979 are running and indicates a positive trend of declining utilization of these older units. However, this older pool of units was still relied upon, to provide either energy or reliability services, for roughly 34 percent of the hours in 2006. Because of the age and relative inefficiency of these units, they are likely to have net revenues below those reported in Section 2.6.3 and have less ability to recover even fixed O&M costs through spot market revenues. For these units, long-term contracting is especially necessary to ensure continued operation in the short-run and re-powering of these facilities in the longer-run if new investment is insufficient to provide replacement capacity.

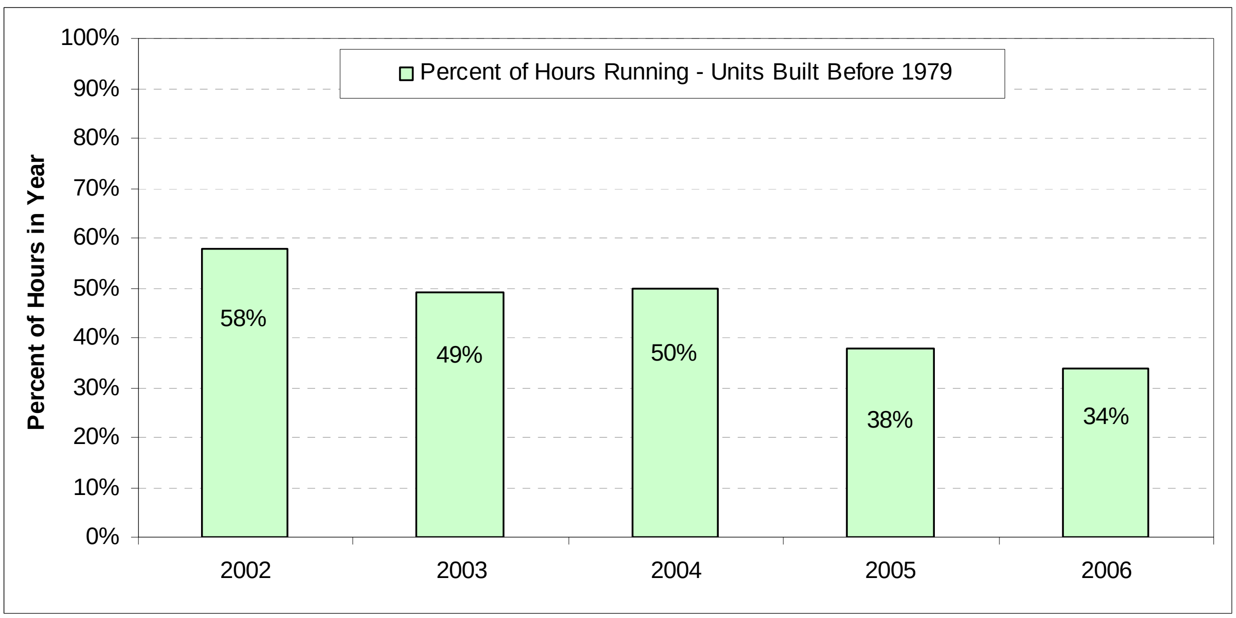
[17] It is important to note that this table only shows part of the supply picture in SP15. Numerous transmission upgrades have also occurred within SP15 to improve generation deliverability within the zone; however, despite these improvements, meeting summer peak load demands in SP15 remains extremely challenging.

Table 2.14 Characteristics of California's Aging Pool of Resources

	Number of Units	Unit Capacity[1]	Average Unit Age (Years)[2]	Capacity Factor[3]	Percent of Hours Running[4]
North of Path 26	13	4,642	45	14%	34%
South of Path 26	33	9,304	43	11%	34%
Total	**46**	**13,946**	**43**	**12%**	**34%**

[1] Total active unit capacity as of date of publication.
[2] Based on build date.
[3] Based on 2005 data. Does not adjust for unit outages.
[4] Based on 2005 data. Percent of all hours in year where unit showed positive metered generation.

Figure 2.43 Percent of Hours Running for Units Built Before 1979



2.7 Performance of Mitigation Instruments

2.7.1 Damage Control Bid Cap

As previously discussed, the Damage Control Bid Cap for energy bids was changed from \$250/MWh to \$400/MWh on January 14, 2006 and the bid cap for ancillary service bids was increased from \$250/MW to \$400/MW on February 13, 2006. This increase was prompted by concerns that the significant increase in natural gas prices seen in the fourth quarter of 2005 may persist and create circumstances where it was not economic for some less efficient resources to offer into the CAISO market. While the change from $250/MWh to $400/MWh is significant, the bid price caps in the CAISO markets are still significantly lower than bid price caps in other ISOs. The CAISO recognizes that higher bid price caps do introduce benefits that can be market enhancing. For example, the prospect of higher market prices for energy may provide incentives for generation owners to maintain resources in a higher state of readiness to take advantage of the higher prices during peak demand periods, increasing overall grid reliability and offers into the imbalance market. On the load side, the threat of exposure to higher spot prices that are possible under a higher bid price cap will provide incentives to LSEs to hedge this risk through greater reliance on longer-term energy contracts, which not only reduces risk to LSEs but also provides a more stable revenue environment for supply and a more reliable financial environment to facilitate new investment. In addition to providing incentives for greater use of longer-term contracts, higher bid price caps can also provide greater incentives to further development of demand response as a price risk mitigation instrument. This not only provides risk mitigation to load, but also improves the CAISO's ability to manage the grid reliably under extreme peak conditions and acts as an additional market power mitigation measure, providing some additional price response during periods where there is not an abundance of excess supply and an individual supplier's bids may be able to exercise market power. The 2006 increase in the bid price cap to $400/MWh is the first of several steps to increase bid price caps in the CAISO markets to $1,000/MWh, more in line with levels seen in other ISOs and where these market benefits may become more pronounced. The impact of the higher energy bid cap is covered in various analyses provided in Chapter 2, Chapter 3, and Chapter 4.

2.7.2 AMP Mitigation Performance

In addition to a Damage Control Bid Cap, the CAISO also has a bid conduct and market impact Automated Mitigation Procedure (AMP) for addressing potential economic withholding. There are basically three components to the AMP.

1) A $91.87 predicted price screen for determining whether to apply bid conduct and market impact tests.

2) A bid conduct threshold equal to a bid increase relative to the unit's reference price of $100/MWh, or 200 percent, whichever is lower.

3) A market impact threshold equal to a market price impact of $50/MWh or 200 percent, whichever is lower.

All of the AMP procedures are run during the pre-dispatch process for selecting inter-tie bids and as such are based on predicted 15-minute interval prices within the hour. With respect to the price screen test, if any of the predicted 15-minute prices exceed $91.87/MWh in any zone, the bid conduct and market impact tests are applied. The market impact test is based on the difference of average market price of all four 15-minute prices. All impact test failures will lead to actual offer mitigation.

In 2006, impact test failures appeared for the first time since the AMP software became functional and AMP started to mitigate bids for incremental energy. The frequency of AMP impact test failures increased during the summer peak months especially in July and August (Table 2.15). The number of conduct test failures reached a peak at the beginning of 2006, as a consequence of gas price increases after the hurricane season in 2005 that lingered over to 2006.[18]

Table 2.15 Frequency of AMP Conduct and Impact Test Failures

	Conduct Test Failure	Impact Test Failure
Jan-06	99	2
Feb-06	38	0
Mar-06	52	0
Apr-06	35	1
May-06	29	2
Jun-06	1	0
Jul-06	37	11
Aug-06	20	5
Sep-06	6	0
Oct-06	18	2
Nov-06	60	0
Dec-06	56	2
Total	**451**	**25**

Evaluation of the AMP Price Forecast

The effectiveness of the AMP can be impacted by unforeseen events that occur during the gap between the time when the AMP software run is completed and the time of actual market operation. The market energy offers will be subject to the AMP conduct and impact tests only in cases where the real-time market-clearing price is expected to exceed $91.87/MWh in any zone in any 15-minute interval during the hour of operation. Due to operational system limitations, this price screen effectively is applied 53 minutes prior to the hour of operation based on the projected imbalance energy dispatch for that hour of operation. This means that if AMP is not triggered due to an expected price greater than $91.87/MWh in the next hour at 53 minutes before that hour, AMP will not be triggered at all for the next hour, even if a contingency occurs after 53 minutes before the beginning of the hour that causes the actual price to be greater than $91.87/MWh (an interval of time of one hour and 53 minutes).

This section examines the extent to which the AMP was able to correctly forecast prices above $91.87, which is the screen for determining whether the AMP (bid conduct and market impact test) should be run. It should be noted that since the deployment of RTMA certain results of the AMP are no longer accessible for data analysis. In particular, the results of the predicted price screen used to determine whether AMP is activated are not available for analysis. Consequently, the scope of this analysis is limited to data that remains available, which can be categorized as the following two groups:

[18] There was a software versioning issue with the execution of AMP during the months of May and June, 2006, that interfered with the proper application of the mitigation procedure. The execution error was benign in all but nine hours during these two months. Preliminary analysis indicates that the potential impact of this error, in terms of eliminating the impact of the exercise of market power on market clearing prices, was minimal. During nearly all of the affected intervals, the price for imbalance energy was below $90. The CAISO has put in place measures that will preclude this type of AMP failure from occurring in the future.

1) The results of AMP software:

    a) No action.

    b) Conduct test failure

    c) Impact test failure and associated offers mitigation.

2) The results of RTMA five minute interval prices. These actual prices are produced by offers that have passed the AMP. The internal conduct test and impact test price predictions are not available for analysis. Since the AMP software uses 15 minutes as one interval and RTMA software uses 5 minutes as one interval, the 15 minute average of 5 minute RTMA prices are considered in the evaluation.

Table 2.16 summarizes the results of the AMP's capability to accurately predict prices above $91.87/MWh.

Table 2.16 AMP Price Prediction Accuracy (2006)

		Hours at least one Avg. 15 Minute RTMA price greater than $91.87/MWh	Hours 15-Minute RTMA price less than $91.87/MWh	Total Hours	Predictive Consistency
AMP predicted prices < 91.87		763	7546	**8309**	91%
Conduct Test Failure*	Impact Test Pass	179	247	**426**	42%
	Impact Test Failure	16	9	**25**	Inconclusive
	Total Hours	**958**	**7802**	**8760**	

* In all hours where the AMP predicted a price greater than 91.87, there was at least one conduct test failure.

The following observations can be drawn from the results:

- There were 763 hours when at least one 15-minute interval of actual RTMA prices was above $91.87/MWh which the AMP software failed to predict. However, in the vast majority of hours (7,546), both AMP and RTMA 15-minute average prices were below $91.87/MWh, which represents a 91 percent consistency factor.

- In hours when the AMP did run (i.e., AMP predicted a 15-minute price above $91.87/MWh) but no mitigation occurred (i.e., no market impact test failure), the AMP correctly predicted that at least one 15-minute price would be above $91.87 in 42 percent of the 426 hours that AMP ran without mitigating.

- In the hours when the AMP ran and mitigated, the results of the price predictive capability of the AMP are inconclusive as it is not possible to know what actual real-time prices would have been in the absence of bid mitigation.

Evaluation of the Impact Test

The effectiveness of the AMP may also be affected by imperfectness of the impact test and the associated criteria. Since the intermediate system prices using both the original offers and mitigated offers are not accessible, we use the average hourly RTMA price of $250/MWh in any zone as a benchmark to determine whether or not the mitigation should have been triggered. The choice of $250/MWh is due to the fact that it is a relatively high price and no offers were mitigated prior to 2006 when the soft offer cap was set at the same level in the Real Time Energy Market.

To evaluate the performance of the impact test, market hours were categorized with respect to: 1) whether the price screen was expected to trigger AMP; 2) conduct test results; and 3) impact test results, as seen in Table 2.17.

Table 2.17 Impact Test Evaluation results

Average RTMA Hourly Price Greater than $250/MWh	Conduct Test	Impact Test	Number of Hours
Yes	Fail	Fail	3
No	Fail	Fail	22
Yes	Fail	Pass	3
Yes	Pass	Pass	13

The following observations can be drawn from Table 2.17.

- Out of 25 hours of conduct and impact test failures (i.e., bid mitigation), the RTMA hourly average prices dropped below $250/MWh in 22 hours.

- Out of 25 hours of conduct and impact test failures (i.e., bid mitigation), there were 3 hours when the RTMA hourly average prices were still higher than $250/MWh. This may be due to the following reasons:

  - ♦ The right set of generators were mitigated but the reference price curves used to replace the original offers were very high or,

  - ♦ Some generating units had very high bids that did not violate the conduct test and set the price.

- There were 16 hours when the RTMA prices were higher than $250/MWh but no offers were mitigated by AMP.

  - ♦ In 13 hours out of 26 hours, the offers passed the conduct test in the first place. This may be caused by bad price prediction or sudden system condition changes between the completion of the AMP run and the start of the actual operating hour.

  - ♦ In the other 3 hours, the offers failed the conduct test but passed the impact test. This may be caused by high reference price level.

3 Real Time Market Performance

3.1 Overview

2006 marked the second full year of operation under the new Real Time Market Application (RTMA) software. The RTMA software was designed to address significant shortcomings in the prior real-time dispatch and pricing application (Balancing Energy and Ex-Post Pricing or BEEP).

The RTMA software uses a 120-minute time horizon to compare the load forecast, current and expected telemetry of resources in the CAISO Control Area, current and expected telemetry of transmission links to other control areas, and the current status of resources on Automatic Generation Control (AGC). From this information, RTMA sets generation levels for resources participating in the CAISO Real Time Market using an optimization that achieves least-cost dispatch while respecting generation and inter-zonal constraints.

A complementary software application, Security Constrained Unit Commitment (SCUC), determines the optimum short-term (i.e., one to two hours, the time from the current interval through the end of the next hour based on the current and next hour's bids) unit commitment of resources used in the RTMA. The SCUC software commits off-line resources with shorter start-up times into the Real Time Market for RTMA to dispatch, or, conversely, the SCUC software de-commits resources as required to prevent over-generation in real-time. The SCUC program runs prior to the beginning of the operating hour and performs an optimal hourly pre-dispatch for the next hour to meet the forecast imbalance energy requirements while minimizing the bid cost over the entire hour. The SCUC software also pre-dispatches (i.e., dispatches prior to the operating hour) hourly inter-tie bids.

This chapter reviews the performance of the CAISO Real Time Market in 2006. Section 3.2 provides a general review of RTMA prices and dispatch volumes compared to prior years. One significant driver on Real Time Market volumes is the level of forward energy scheduling, which is influenced by the CAISO 95 Percent Day-Ahead Scheduling Requirement (Amendment 72). Section 3.3 provides a review of load scheduling practices under Amendment 72. Section 3.4 provides a more detailed assessment of several aspects of RTMA beginning with a review of overall price volatility (Section 3.4.1). One element of RTMA that has not been implemented is the penalty provisions for deviations from dispatch instructions (Uninstructed Deviation Penalty (UDP)). This element has not been implemented because uninstructed deviations have been relatively moderate since RTMA was implemented. An analysis of uninstructed deviations under RTMA is also provided in Section 3.4.2. Another important aspect of RTMA is a load bias feature that allows operators to manually adjust the load forecasts that are used to determine optimal dispatch in RTMA. A review of the relationship between the use of load bias and the use of regulation energy is also examined in Section 3.4.3. Finally, 2006 is the first complete operating year of Amendment 66 for import/export bids over inter-ties with neighboring areas, which was an amendment to the CAISO tariff to correct problems with the prior settlement rules for pre-dispatched inter-tie bids that lead to excessive uplift payments. The impact of Amendment 66 is examined in Section 3.4.4.

3.2 Real Time Market Trends

3.2.1 Prices and Volumes

Figure 3.1 shows monthly average prices and volumes for both incremental and decremental energy and both in and out-of-sequence (OOS) dispatches for 2005 and 2006. Monthly average prices for incremental energy in 2006 were stable, averaging between $60 and $80/MWh with the exception of $88/MWh in January due to the remaining effect of the dramatic increase in natural gas prices resulting from the Gulf Coast hurricanes. Average monthly prices for decremental energy were relatively low during the first half of 2006 at around $20/MWh, mainly due to abundant hydroelectric generation, but increased to around $40/MWh for the rest of the year. Average monthly prices for OOS incremental prices were lower than the in-sequence prices in most months of 2006, with the exception of July when California experienced the record-breaking heat wave and some relatively higher cost OOS dispatches were required to maintain the reliability of the grid. As in 2005, in-sequence dispatch volumes were overwhelmingly decremental in most months of 2006, especially during the spring and summer months. The preponderance of decremental dispatches in 2006 can be attributed to:

- Unusually high levels of hydroelectric output in northern California and the Pacific Northwest which resulted in over-generation conditions as well as inadvertent loop flows.
- An extremely high level of forward energy scheduling – driven in part by the CAISO day-ahead load scheduling requirement (Amendment 72).

Figure 3.1 Monthly Average Dispatch Prices and Volumes (2005-2006)

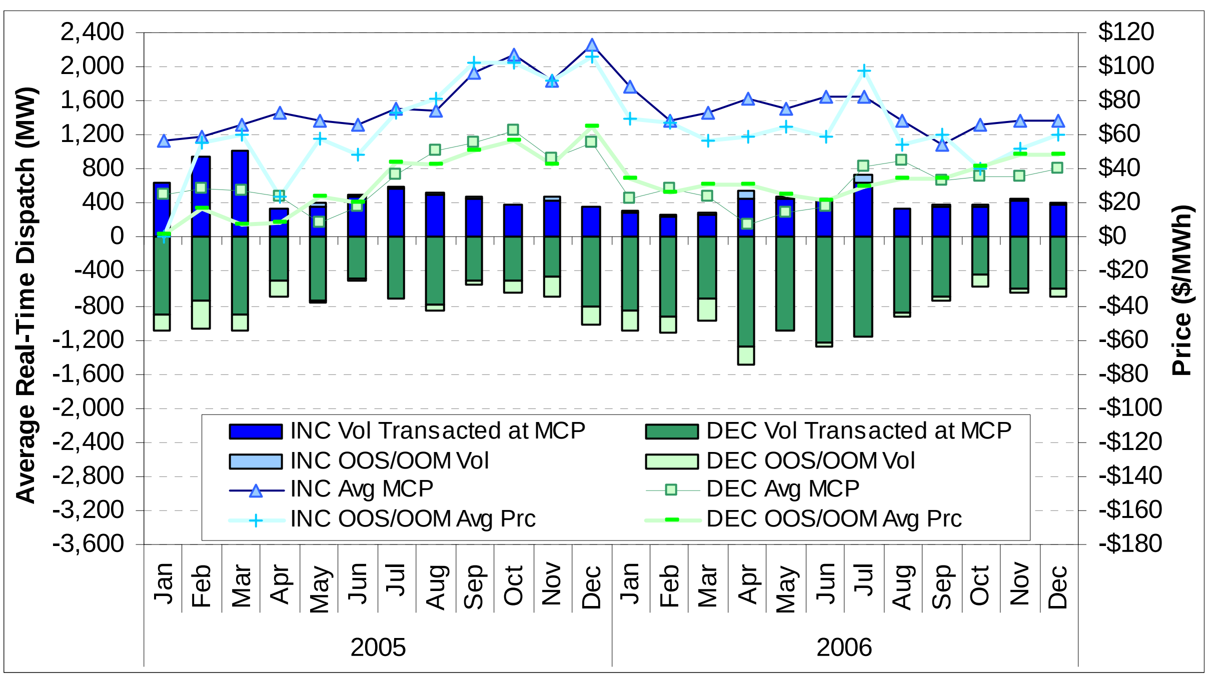


Figure 3.2 and Figure 3.3 show the same metrics presented in Figure 3.1 but separately for peak and off-peak hours, respectively. As can be seen in these figures, the average monthly market volume trends across the two years are fairly similar for peak and off-peak hours. However, there were generally higher decremental volumes during the peak hours in the spring of 2006, which as noted above can be attributed to high levels of forward scheduling and unscheduled over-generation due to high levels of hydroelectric generation. As expected, average monthly prices were generally higher in the peak hours.

Figure 3.2 Monthly Average Dispatch Prices and Volumes in Peak Hours (2005-2006)

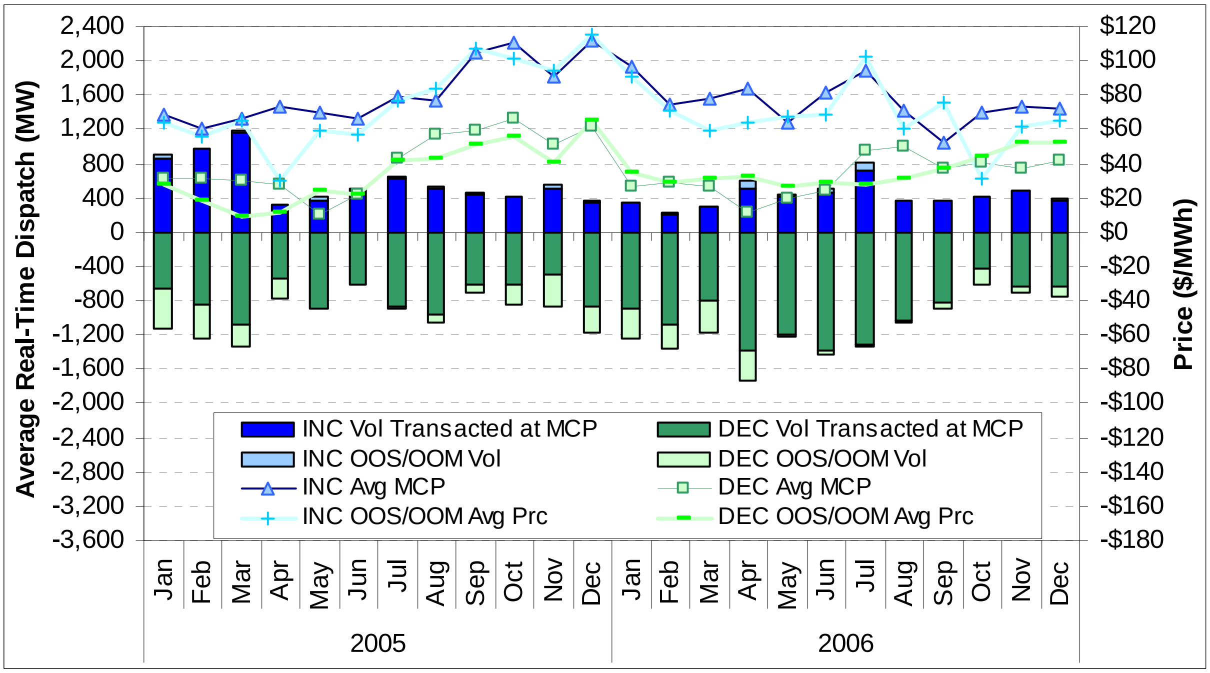


Figure 3.3 Monthly Average Dispatch Prices and Volumes in Off-peak Hours (2005-2006)

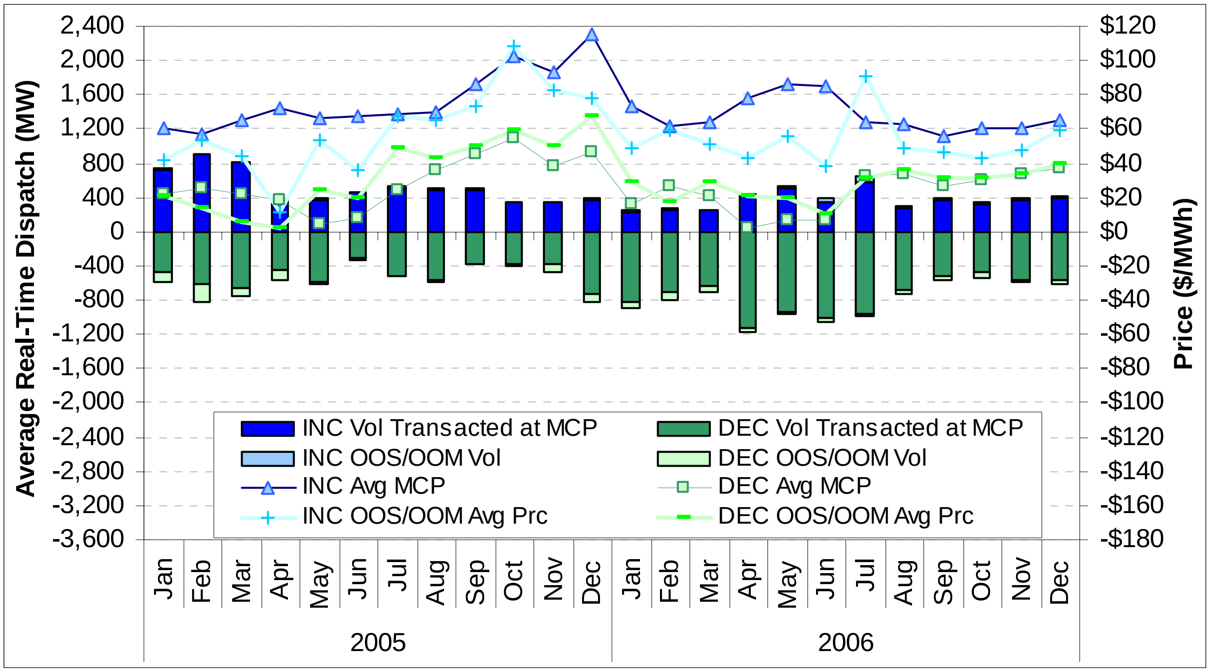


Figure 3.4 compares average annual Real Time Market prices by zone (NP26, SP15) for 2002 through 2006. Congestion on Path 26 in the north-to-south direction has resulted in consistently higher prices in SP15 than in NP26. This congestion was largely responsible for the zonal crest in prices in 2004, whereas natural gas prices accounted for system-wide increases into 2005. As natural gas prices decreased, new transmission and generation was deployed across the control area, and there was robust hydroelectric production in 2006, prices moderated. However, because much of the hydroelectric power is sourced in NP26 and the Pacific Northwest, Path 26 congestion persisted, and continued to result in higher SP15 prices.

Figure 3.4 Average Annual Real-Time Prices by Zone (2002-2006)[1]

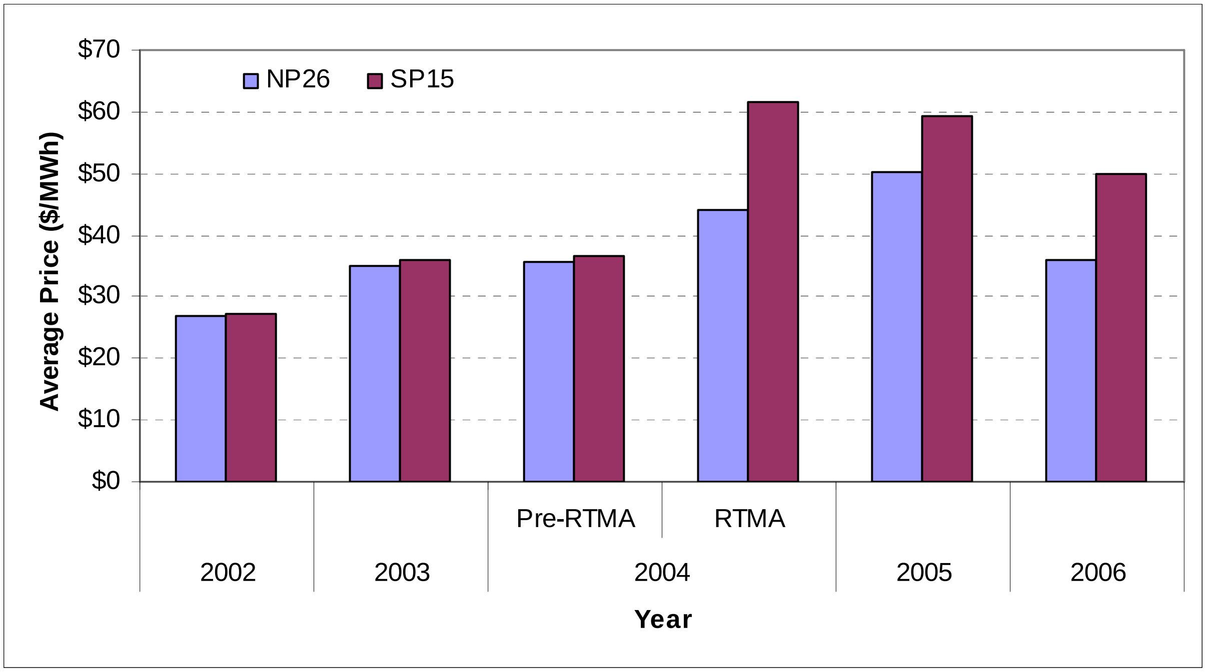


Figure 3.5 shows SP15 real-time 5-minute interval price duration curves for 2003 through 2006 and indicates that real-time interval prices in 2006 were generally lower than in 2005 with the exception of the very extreme end of the distribution (i.e., 1.8 percent of 5-minute price intervals), predominately because of an increase in the bid cap from $250/MWh to $400/MWh and an increase in the frequency of 5-minute price spikes. On the lower end, 2006 experienced more negative prices for about 2.5 percent of 5-minute intervals, which was the highest in four years. The increase in negative prices in 2006 is predominately attributable to high levels of hydroelectric generation and high levels of forward scheduling, both of which increased demand for decremental energy bids, and, under severe conditions, resulted in exhausting the supply of decremental bids.

[1] Chart incorporates most recently available information and may differ from prices reported in previous years. Averages are real-time volume-weighted.

Figure 3.5 SP15 Price Duration Curves (2003-2006)

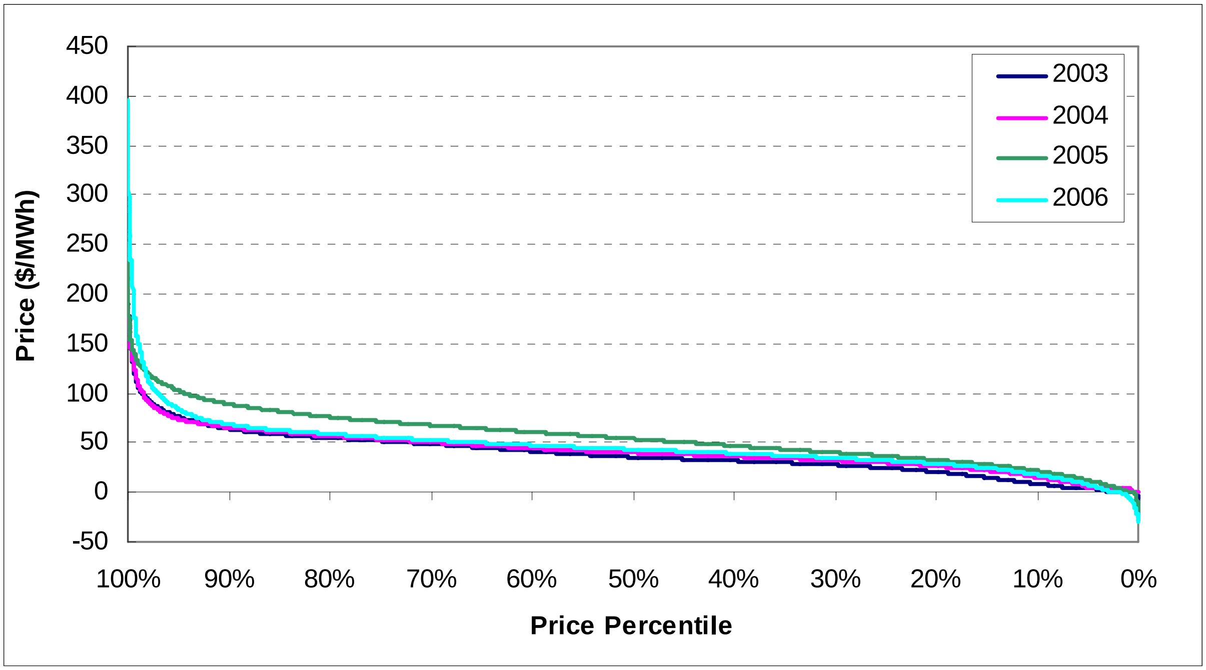
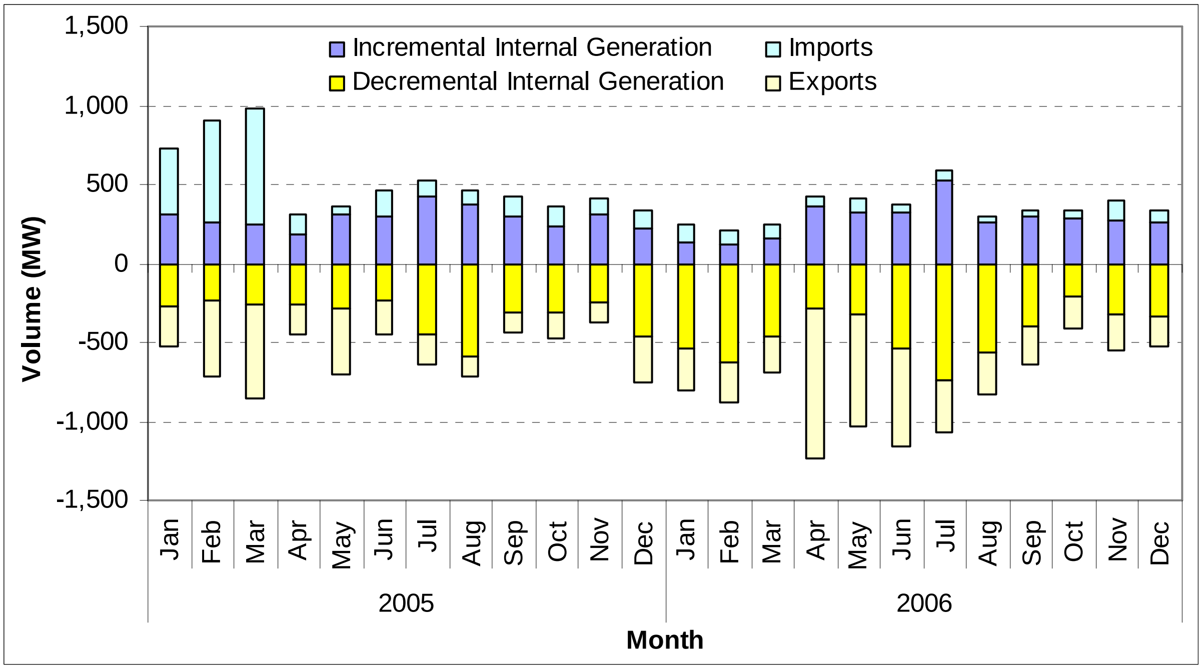


Figure 3.6 shows the monthly average dispatch volumes for internal generation, imports and exports for 2005 to 2006. With the exception of the three-month period of January 2005 - March 2005, internal resources constituted the majority of RTMA dispatches. The increase in inter-tie dispatches during the January 2005 - March 2005 time period is attributed to the “bid or better” settlement rules for inter-tie bids that are pre-dispatched under RTMA. This rule, coupled with the increasing volume of market clearing inter-tie bids, created significant market uplifts and resulted in a modification to the CAISO tariff that replaced the “bid or better” settlement with an “as-bid” settlement rule. The impact of this rule change can be seen in Figure 3.6 by the highly pronounced decrease in inter-tie dispatch volumes beginning in April 2005. This issue is discussed in greater detail in Section 3.4.4. Most notable in 2006 is the high level of export bids dispatched in the April to June timeframe. These dispatches were to address over-generation conditions as well as potential loop-flow problems exacerbated by the high level of hydroelectric generation.

Figure 3.6 Monthly Average Dispatch Volumes for Internal Generation, Imports, and Exports (2005-2006)



3.2.2 Price Spikes

For the period January 1, 2005, through January 13, 2006, during which the price cap was $250, the SP26 price came within $1 of the price cap in 163 of 108,864 5-minute pricing intervals, or approximately 0.1 percent of all 5-minute intervals. Between January 14 and December 31, 2006, SP26 prices exceeded the $250 threshold in approximately 1,006 of 104,964 5-minute intervals, or just under 1 percent of all 5-minute intervals.

The sharp increase in Real Time Market price spikes in 2006, shown in Figure 3.7 for the March to May timeframe, is primarily attributable to an abundance of hydroelectric generation, which resulted in less thermal resources being on-line and available to the Real Time Market. Because of water management constraints and other operational considerations, hydroelectric resources are not always offered to the Real Time Market and are not subject to the same must-offer requirements as thermal resources. As a result, the supply of 5-minute dispatchable bids was limited during this period, particularly during critical ramping hours when demand for incremental energy is greatest. As a consequence, 5-minute interval price spikes in the spring occurred with greatest frequency during these ramping hours. In contrast, price spikes during the June to July period occurred more frequently during the peak hours of the day. This trend can be seen in Figure 3.8.

Figure 3.7 Price Cap Hit Frequencies by Month, During Periods of $250 and $400 Price Caps, 2005-2006[2]

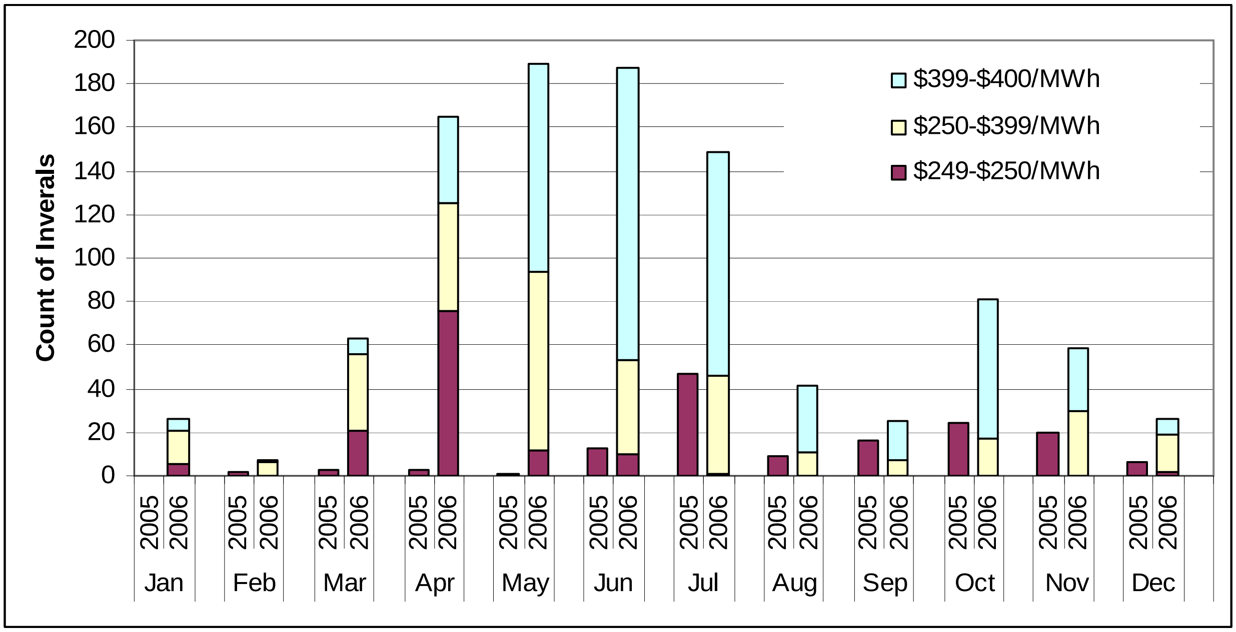
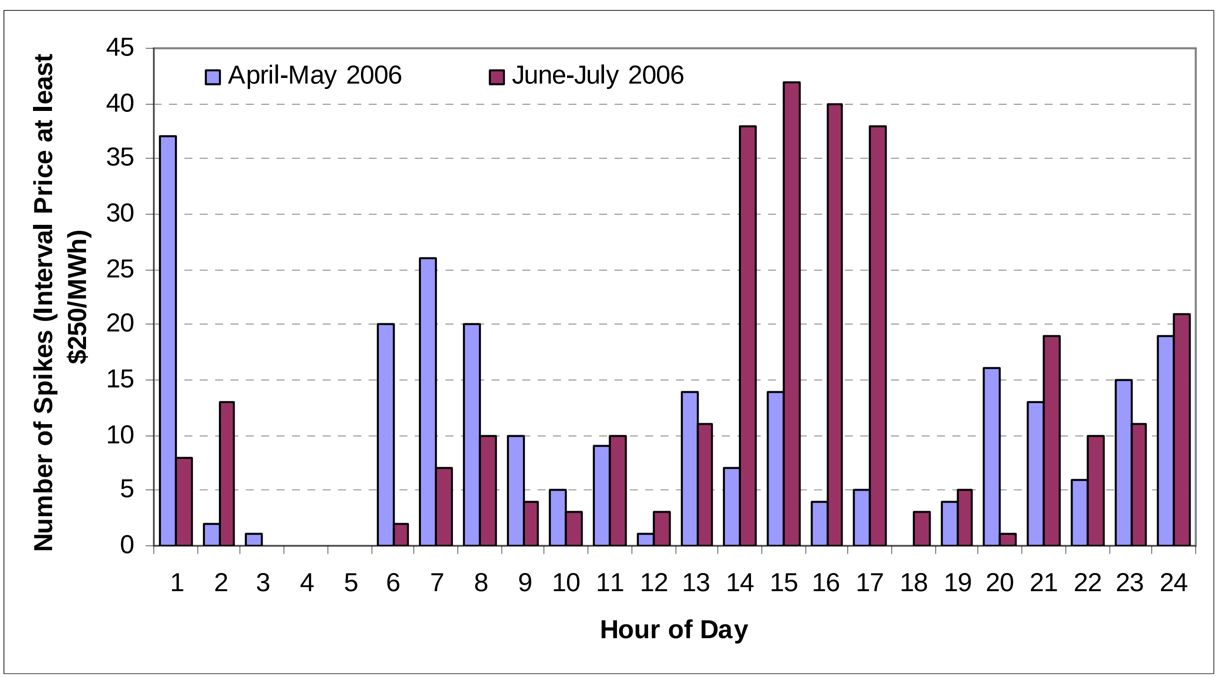


Figure 3.8 Spikes by Hour of Day: April-May and June-July 2006[3]



[2] Price cap was raised from $250 to $400/MWh on January 14, 2006. Data from January 1-13, 2006, prior to the price cap increase, are not shown.

[3] Time periods are actually April 1 through June 2 and June 3 through August 4, 2006, in order to normalize for days of the week.

While price spikes were significantly more prevalent in 2006 compared to 2005 and occurred at higher price levels due to the increase in the bid cap, the cost impact to load from these spikes was relatively minor given the low market volumes settled at these prices and the fact that a significant share of that volume is utility owned or contracted generation.

It is not possible to determine the actual cost impact of the higher bid cap as this would require knowing what the bids and market volumes would have been had the bid cap remained at $250/MWh. For example, the soft-bid cap increase may have resulted in lower Real Time Market volumes and more 5-minute dispatchable supply than would have been the case under a $250 soft-bid cap since market participants would have a greater incentive to reduce their exposure to real-time purchases and increase their opportunities for real-time sales. However, not knowing what the counter-factual market bids and volumes would have been under the $250 soft-cap and prevailing market conditions makes it impossible to precisely assess the impact. Given this limitation, a simplified approach to estimate the impact is to assume that the only change from raising the soft-cap to $400 is the occurrence of some 5-minute interval prices in excess of $250/MWh that would have otherwise been $250/MWh had the $250 soft cap remained in place.

In a prior report to the CAISO Board of Governors, DMM used the simplified methodology described above to estimate the impact of the higher bid cap for the period of January 15 through April 30, 2006. That analysis is shown below to provide an indication of the relative impact of the higher cap. Specifically, Table 3.1 provides the estimated market impacts of price spikes over $250 in the Real Time Market for the January 15 – April 30 period. As shown in Table 3.1, total net costs to Load Serving Entities (LSEs) due to 5-minute interval prices over $250 for this period are estimated at about $1.3 million, or about 2.3 percent of the total cost of Instructed Incremental Energy during this period.

Table 3.1 Estimated Market Impact of MCPs over $250 (Jan-Apr 2006)

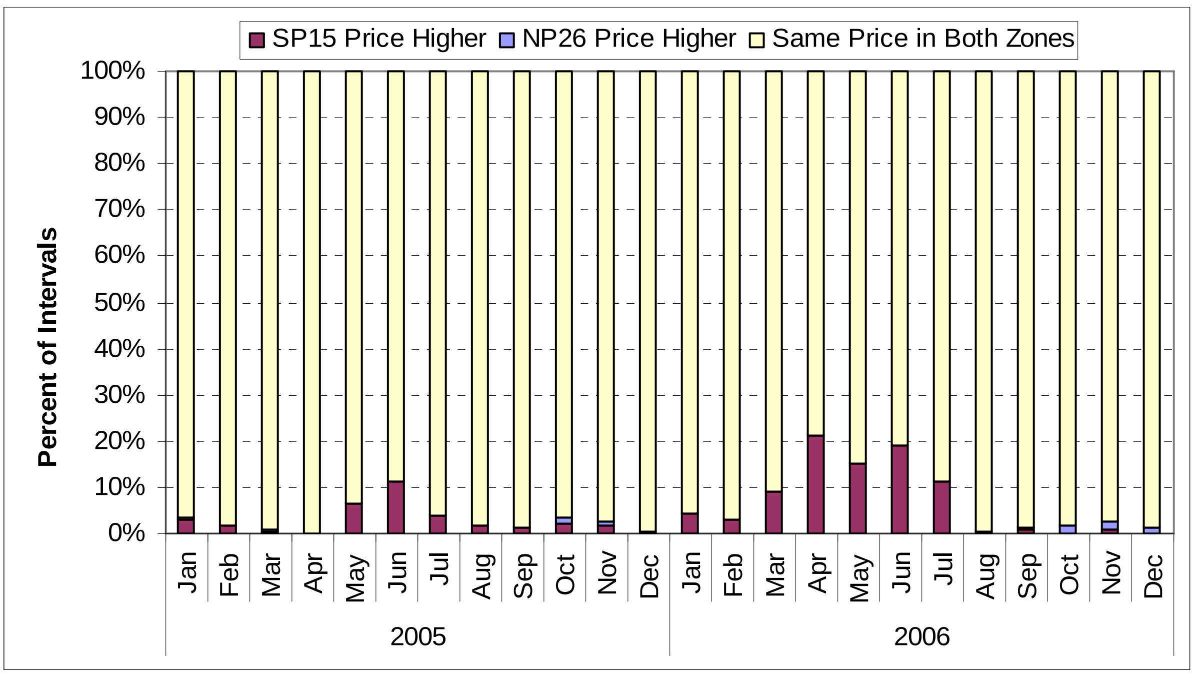
	Instructed Incremental Real Time Energy (IE)			Estimated Net Costs to LSEs	
Month	**Total Costs**	**Cost Due to MCP > $250**	**% of Total IE Costs**	**Total**	**% of Total IE Costs**
Jan 15-Feb	$17,981,783	$405,469	+ 2.3%	$380,445	+ 2.1%
March	$12,421,817	$310,298	+ 2.5%	$56,483	+ .5%
April	$26,489,610	$1,313,784	+ 5.0%	$846,560	+ 3.2%
Total	**$56,893,209**	**$2,029,551**	**+ 3.6%**	**$1,283,488**	**+ 2.3%**

Net costs include estimated uninstructed generation and excludes energy provided by resources owned or under contract to LSEs. Estimated costs do not account for the fact that in some cases, if prices had not exceeded $250, generators would have received higher daily uplift payments, which are paid in cases when a unit's total daily instructed energy payments (based on MCPs) are less than the total bid price of this instructed energy over the course of the day. Thus, data in Table 3.2 may somewhat overestimate the impact of the higher bid cap.

3.2.3 Real-Time Inter-Zonal Congestion

Figure 3.9 shows the monthly count of market splits in 2005 and 2006. Despite an increase in the north-to-south rating for Path 26 of 300 MW (3,700 to 4,000 MW) on June 1, 2006, real-time north-to-south congestion increased on Path 26 in 2006, mainly in the spring and early summer of 2006 when an abundance of hydroelectric generation resulted in significant north-to-south flows on Path 26. Prices differed between NP26 and SP15 in approximately 7.9 percent of 5-minute intervals in 2006, compared to 2.9 percent of intervals in 2005. Another operational issue that can result in splitting the Real Time Market is the Southern California Import Transmission Nomogram (SCIT). The SCIT constraint can be mitigated either by splitting the Real Time Market or by using OOS dispatches within SP15 (intra-zonal congestion management). On other occasions, the CAISO market experienced real-time congestion in the south-to-north direction on Path 15, especially in the fourth quarter of the year, due to derates necessitated by transmission reconductoring work on the Gates-Gregg 230kv line and installation of a switch on the Gates-Midway 500kv line.

Figure 3.9 NP26-SP15 Market Price Splits (January 2005 - December 2006)



3.2.4 Bidding Behavior

Figure 3.10 and Figure 3.11 show profiles of incremental and decremental energy bids from internal resources in SP15 by bid price ranges for 2005 and 2006. Notable in Figure 3.10 is the significant increase in the percentage of higher priced incremental energy bids (over $100/MWh) beginning from September 2005 to January 2006. This trend is largely attributed to the increase in natural gas prices that occurred during this period. Also notable is the increase in incremental bid prices in the $0-$50/MWh range, beginning in January 2006 and increasing throughout most of the year. This trend can be attributed to both lower natural gas prices as well as an abundance of hydroelectric energy. With respect to decremental bids, Figure 3.11 shows that some resources bid very low prices for decremental energy (e.g., below $0/MWh). In

2005, this trend occurred predominately during April – July of 2005 when hydro generation is abundant and demand for decremental bids tends to be greatest. In 2006, this trend occurred through most of the year and included a small proportion of extreme negative bids (i.e., bids below -$10). The category in Figure 3.11 representing bids in the range of -$1/MWh to $0/MWh consisted largely of the hydroelectric bids.

Figure 3.10 SP15 Incremental Energy Bids by Bid Price Bin (January 2005-December 2006)

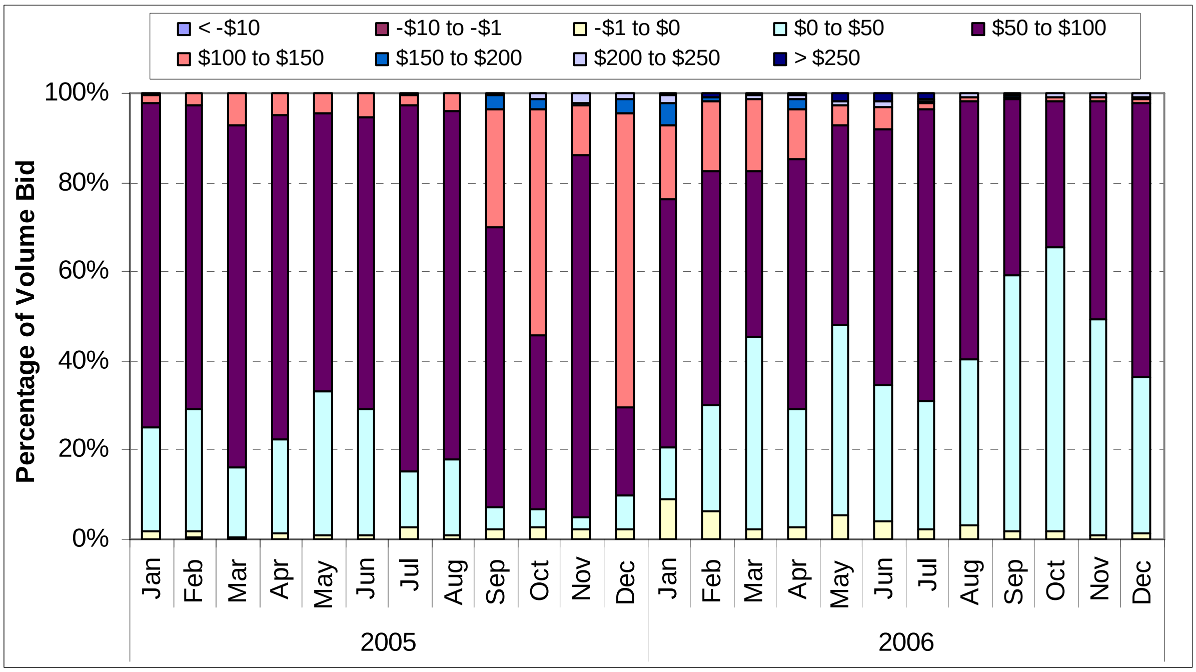
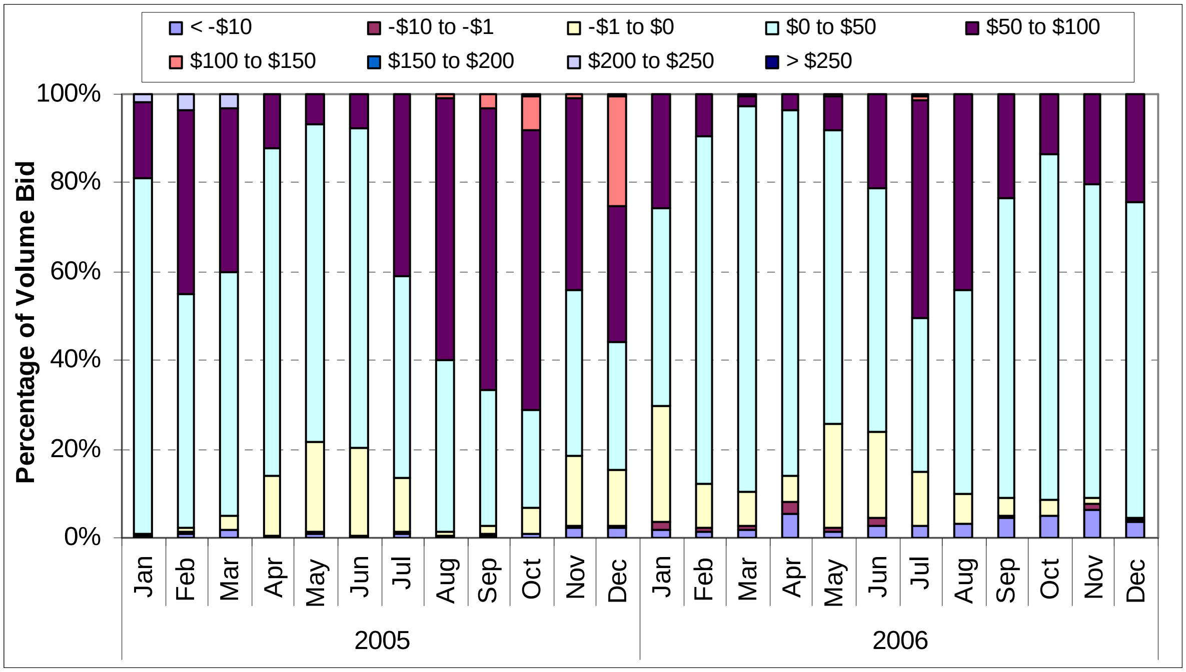


Figure 3.11 SP15 Decremental Energy Bids by Bid Price Bin (January 2005-December 2006)



Decremental bids below the price of $0/MWh were common in 2006 for a variety of reasons:

- Over-generation conditions driven by unusually high levels of hydroelectric output.
- High levels of forward energy scheduling, particularly during peak hours (See Section 3.3).
- Throughout the year, and particularly in the spring, certain hydroelectric resources faced spilling conditions due to high run-of-river water flows. In order to be decremented, resources would have had to divert water from their turbines over the spillway, effectively losing the potential energy for that volume of water.
- During off-peak hours, particularly in the lowest-load hours of 1:00 to 5:00 am, few resources are on and generating above minimum operating capacity. As a result, few units are available to be decremented in these hours. This creates instances where competition is thin among the few providers of decremental energy during these hours.

3.3 Forward Scheduling

Under the current CAISO market structure, there is no organized Day Ahead Market for energy. Instead, all day-ahead scheduling is based on bilateral contracts and supply resources directly owned or controlled by LSEs. In addition, each SC must submit balanced load and supply schedules. The amount of load and supply scheduled on a day-ahead basis can have a significant impact on CAISO operations. To the extent the amount of load and supply scheduled is insufficient to meet the CAISO's forecast of load and other system conditions, the

CAISO may commit additional supply resources on a day-ahead basis through the must-offer waiver denial process. In real time, significant under-scheduling can also require the CAISO to dispatch additional incremental energy resources through the Real Time Market.

During 2006, the level of forward scheduling was quite high, particularly during peak hours. For example, Figure 3.12 compares the average hourly values of day-ahead and hour-ahead schedules with actual load during 2006. This high level of scheduling can be attributed to a number of factors.

- In October 2005, the CAISO filed Tariff Amendment 72, which required Scheduling Coordinators (SCs) to submit day-ahead schedules equal to at least 95 percent of their forecast demand for each hour of the next day. The 95 percent day-ahead scheduling requirement was designed to enhance reliability and reduce the need for the CAISO to take actions to protect against under-scheduling, such as requiring additional capacity to be on-line through MOW denials and dispatching additional energy in the real-time.

- In addition, the amount of forward scheduling in 2006 was affected by a variety of CPUC procurement guidelines which have had the effect of encouraging the state's major Investor Owned Utilities (IOUs) to forward contract for most or all of their projected energy needs.

- Finally, while Resource Adequacy requirements in effect for 2006 only require that available RA capacity be made available to the CAISO, it is likely that many RA capacity contracts are coupled with energy contracts – such as energy tolling agreements – which allow the LSE to schedule energy from RA resources on a day-ahead basis.

During peak hours (and, in particular, hour ending 16), day-ahead schedules often exceeded the 95 percent scheduling requirement established under Amendment 72, as illustrated in Figure 3.14. This trend suggests that factors other than the 95 percent scheduling requirement – such as CPUC supply procurement guidelines, and the bundling of capacity and energy contracts with RA resources – were primarily responsible for the high degree of forward scheduling seen throughout 2006.

Figure 3.13 shows, by month for all hours, average actual load together with day-ahead and hour-ahead under-scheduling. Even in July when average load peaked, the percent under-scheduled was still under two percent of actual load. Figure 3.14 similarly depicts the percentage of under-scheduling for all hours ending 16 by month for 2006. This chart captures the fact that during the peak hours of 2006, the extent of aggregate under-scheduling was slightly less than three percent of actual load.

As discussed in Section 3.2, during many hours in 2006, high levels of scheduling or over-scheduling required the CAISO to reduce or decrement additional generation in the Real Time Market. Even if energy and schedules submitted by SCs area approximately equal actual CAISO system loads, the CAISO may need to decrement significant amounts of energy due to various sources of unscheduled energy that appear in real-time under the current market design. Major sources of unscheduled energy include:

- Minimum load energy from units committed through the MOW process.

- Positive uninstructed energy from resources within the CAISO, including steam generating units operating at minimum load during off peak hours, cogeneration resources, and intermittent resources such as wind energy.

- Additional net incremental energy from real-time out-of-sequence (OOS) dispatches due to intra-zonal congestion and local reliability requirements.

- Loop flows creating net positive energy from neighboring control areas.

In 2006, the limited amount of under-scheduling that did occur did not detrimentally impact system reliability or significantly increase MOW commitment costs primarily due to the fact that the CAISO was decrementing energy in real-time due to various sources of unscheduled energy. For example, Figure 3.15 shows the percent of hours during the year in which the CAISO was decrementing energy along with the average levels of under-scheduling for each of the 24 operating hours of the day. The red portions of the bars depict the MWh by which aggregate day-ahead schedules fell below 95 percent of the CAISO day-ahead forecast. As depicted in Figure 3.15, the bulk of under-scheduling occurred during hours in which the CAISO was, on net, decrementing energy. Thus, under-scheduling did not create a need for additional incremental energy in real-time and, in fact, under conditions such as these, additional forward scheduling may have only increased the need to decrement energy in real-time.

Figure 3.12 2006 Actual Load Relative to Hour Ahead and Day Ahead Schedules

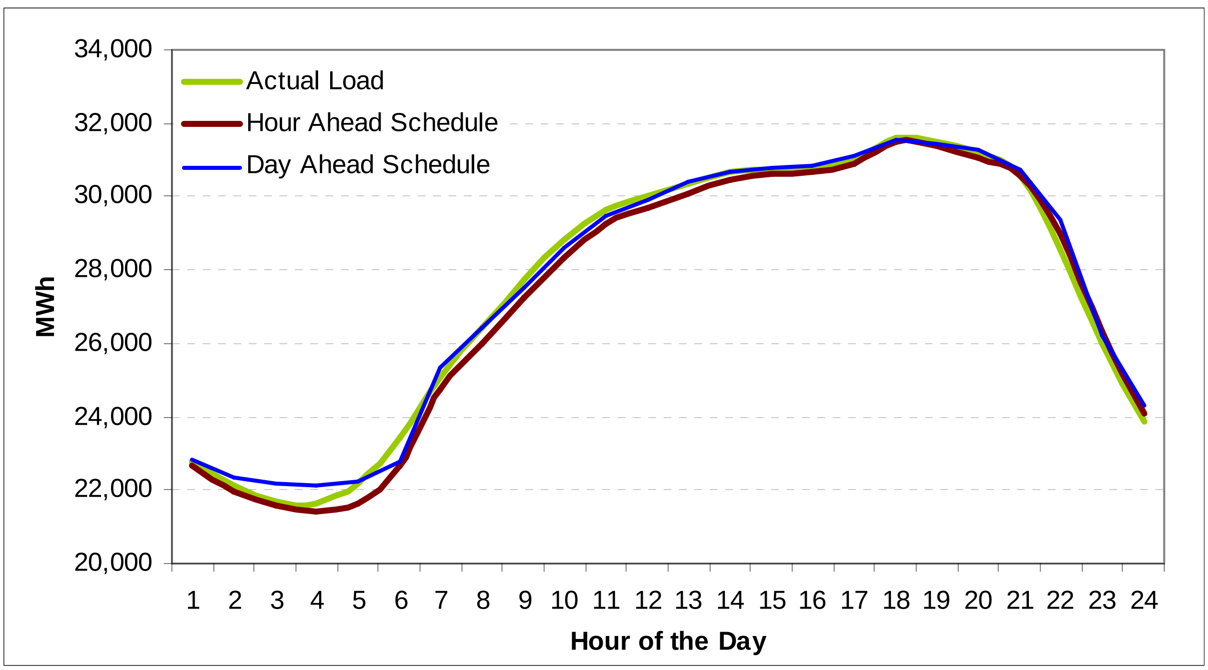


Figure 3.13 2006 Actual Load Relative to Under-Scheduling (Monthly Averages, All Hours)

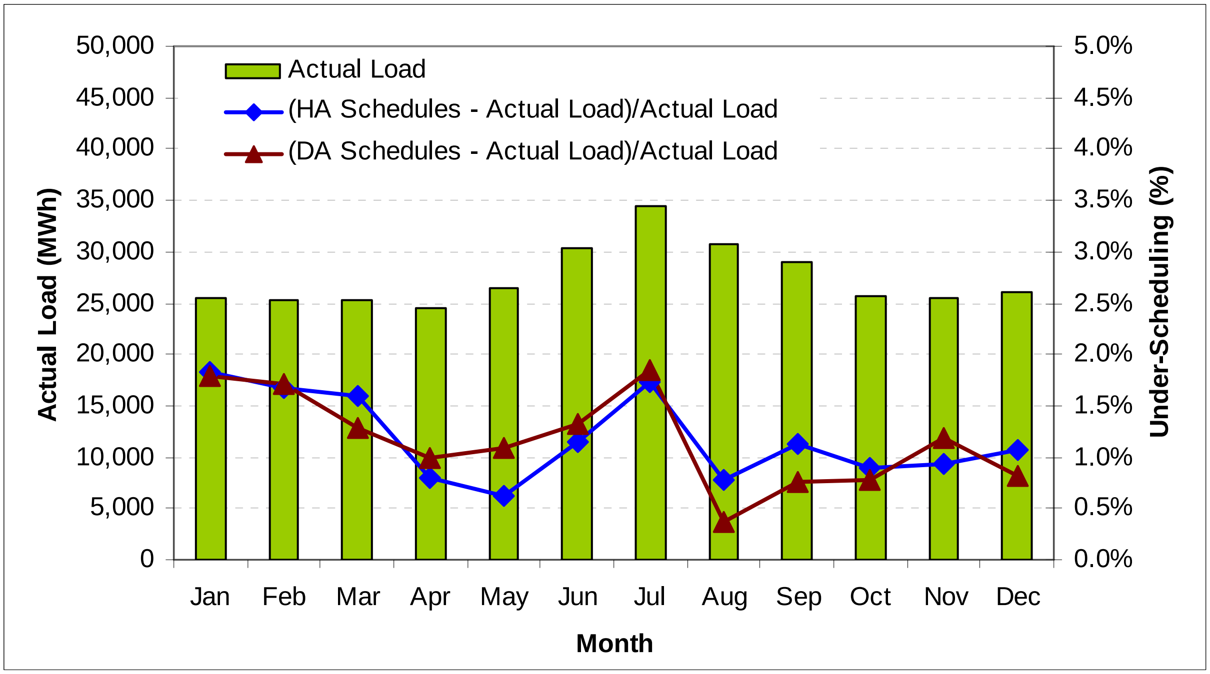


Figure 3.14 2006 Actual Load Relative to Under-Scheduling (Monthly Averages, Hour 16 Only)

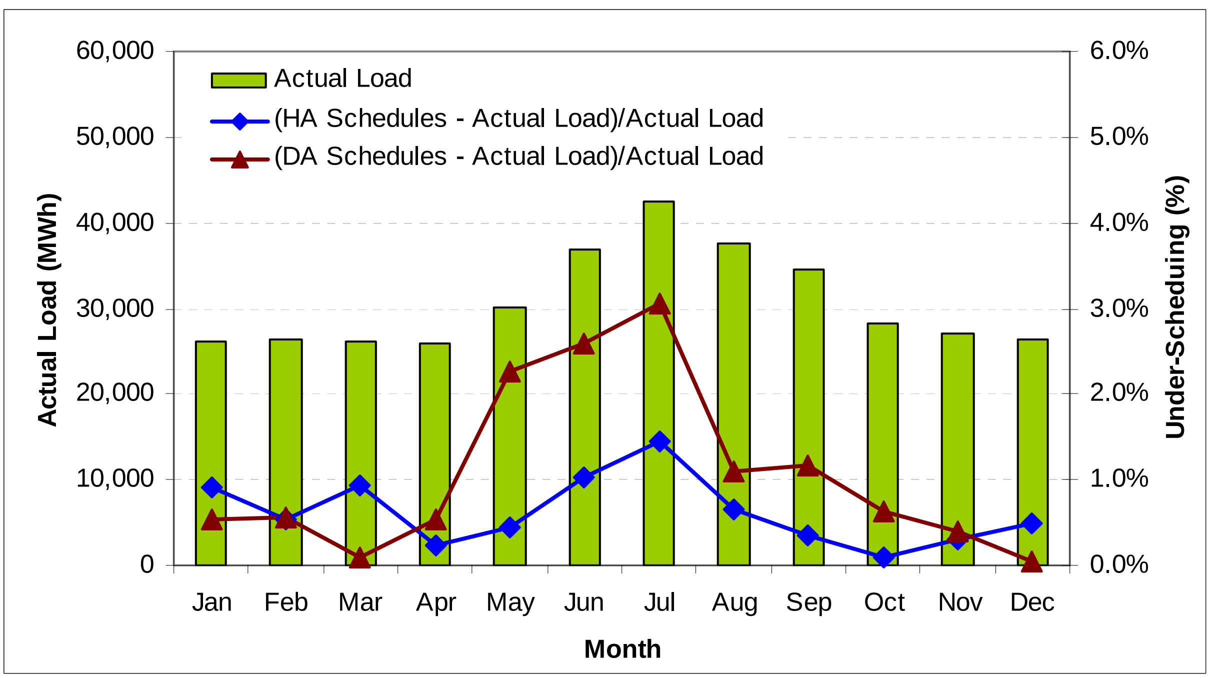
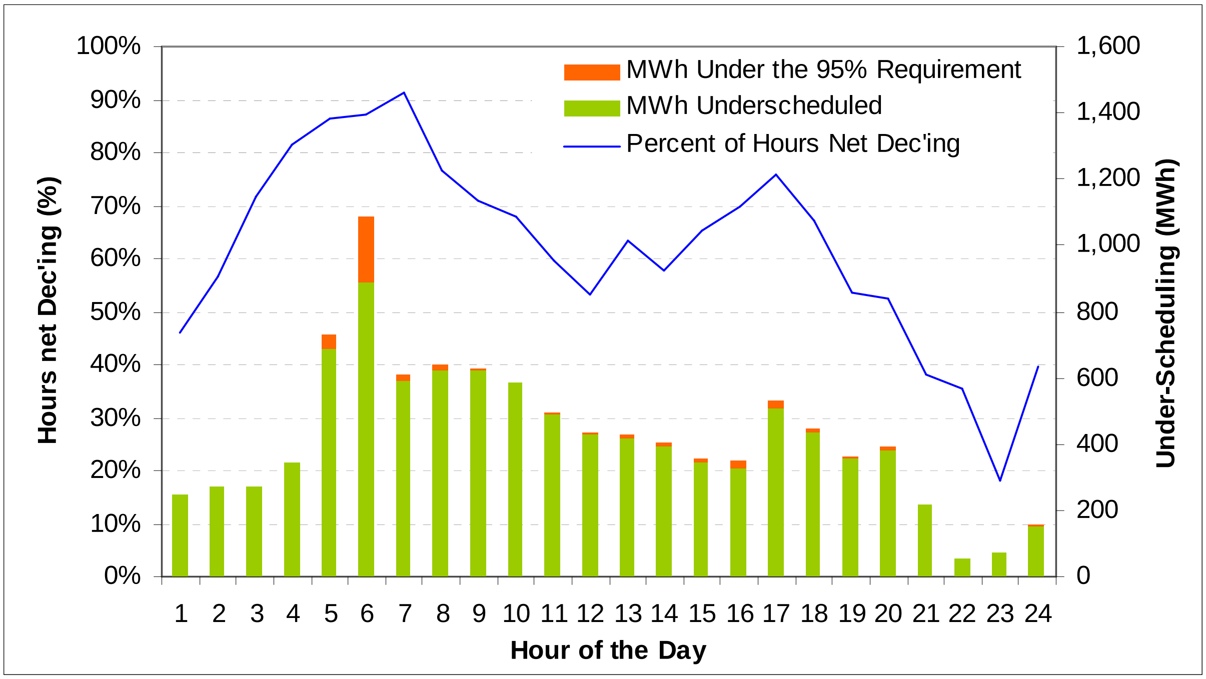


Figure 3.15 2006 Average Under-Scheduling by Hour Relative to Net Decremental Energy



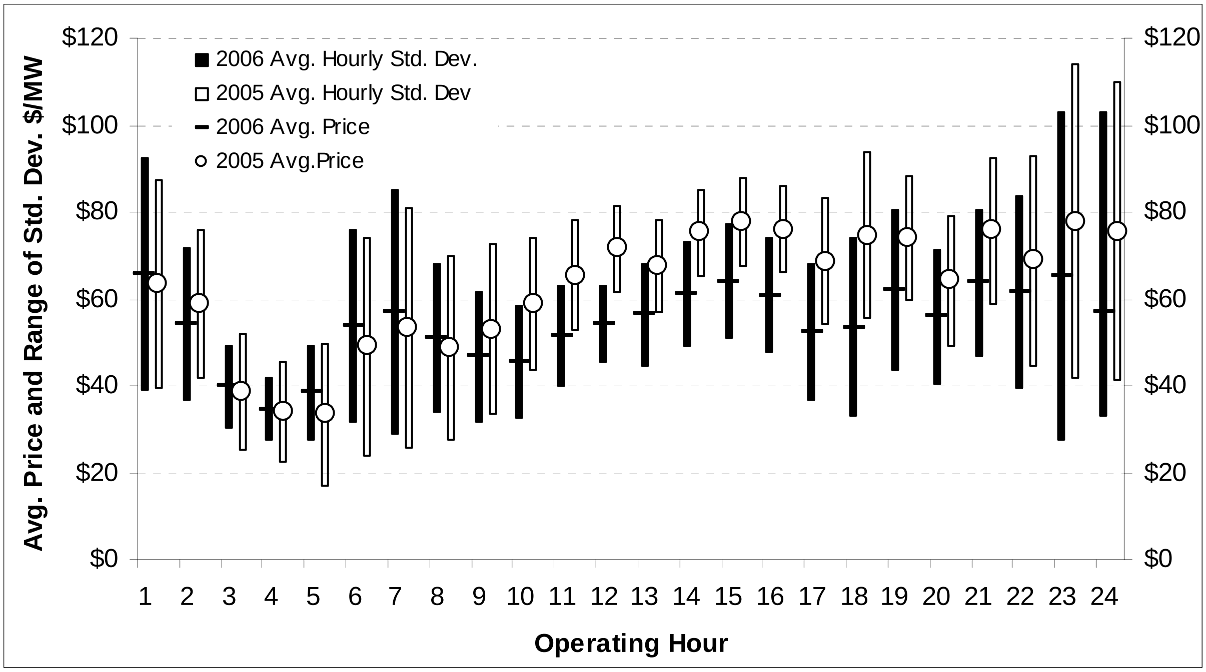
3.4 Assessment of Imbalance Market (RTMA) Performance

3.4.1 Price Volatility

RTMA was designed to address significant shortcomings in the prior real-time dispatch and pricing application (BEEP) in October 2004. One of the major concerns raised about RTMA since its implementation is a perceived high degree of price and dispatch volatility. It should be noted that a real-time imbalance energy market is inherently volatile due to the fact that it is clearing supply and demand imbalances on a nearly instantaneous basis and the market is very thin. A high degree of price and dispatch volatility is not necessarily indicative of poor performance. Rather, the question is whether the volatility is excessive relative to what is required to efficiently clear the real-time imbalances and overlapping bids.

Figure 3.16 compares the average and range of RTMA interval prices for 2005 and 2006 in SP15. The range of prices for each hour shown in Figure 3.16 represents the average load-weighted interval price for that hour, plus and minus the average standard deviation of interval prices within each operating hour. As evident in Figure 3.16, the level of price volatility in 2006 is comparable to 2005 for most hours of the year – suggesting a persistent trend of price volatility.

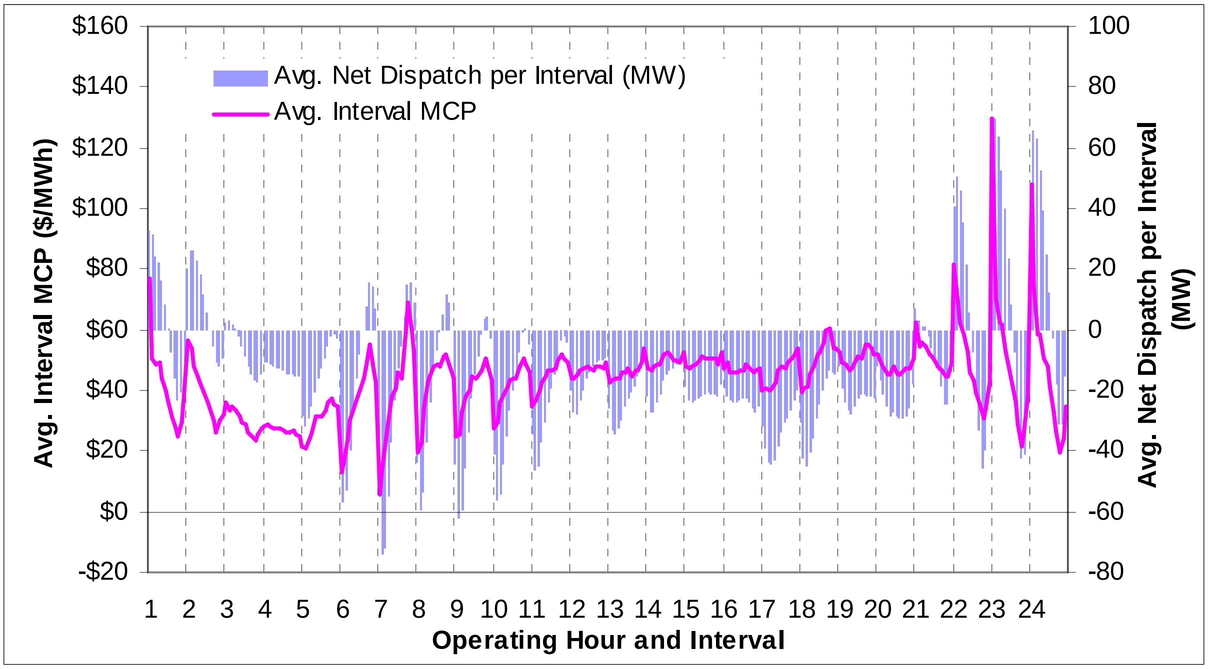
Figure 3.16 Average SP15 Hourly Prices and Standard Deviation (2005-2006)



The average of MCP and net dispatched energy for each interval during the day in 2006 is presented in Figure 3.17. The basic findings are the same as last year. Much of the intra-hour deviation of real-time prices under RTMA can be attributed to intra-hour fluctuations in demand for imbalance energy. There is a very close correlation between the intra-hour price deviations and net quantity of real-time energy dispatched each 5-minute interval since implementation of RTMA. Within each hour, prices are significantly higher when the CAISO is incrementing generation, and lower when the CAISO is decrementing generation. This pattern is especially noticeable during the morning and evening ramping hours when net dispatched energy changes directions from incrementing to decrementing or vice versa due to the rapid load increase or decrease. The volatility of prices and imbalances during those hours are also highest, as shown in more detail in Figure 3.16 and Figure 3.17, respectively.

During the morning ramp hours, prices tend to be lower during the first 15-minutes of each hour as the CAISO typically needs to decrement generation. During these intervals, the need to decrement generation stems from the fact that supply is ramping up to its new hourly schedule faster than the actual increase in loads during the first several intervals of each hour. Conversely, during late night ramp down hours, the prices tend to be significantly higher during the first 15-minutes of each hour as the CAISO typically needs to increment generation. The need to increment generation during these intervals stems from the fact that supply is ramping down to its new hourly schedule faster than the actual decrease in loads during the first portion of each hour.

Figure 3.17 Intra-Hour Price Volatility Under RTMA in 2006



3.4.2 Uninstructed Deviations

Uninstructed deviations are an important aspect of market performance to the extent that they result in a need to excessively dispatch other resources or that they interfere with RTMA's ability to effectively balance the system. As discussed in more detail below, both the volume and interval-to-interval volatility of generating unit uninstructed deviations in 2006 appears to have been relatively consistent with what was observed in 2005, and appears to be within acceptable limits.

The CAISO had previously proposed the Uninstructed Deviation Penalty (UDP) as a feature of the current market design, as well as the upcoming MRTU market design, as an incentive for resources to follow their schedules and CAISO dispatch instructions. UDP was not implemented as part of the current market design because of concerns regarding the manner in which RTMA dispatched generating units and the feasibility of reporting limitations within a 30-minute period necessary to avoid UDP. UDP is planned as a potential feature of MRTU Release 2, which is anticipated to be implemented subsequent to the initial implementation of MRTU, depending on the impact uninstructed deviations have on grid and market operations under MRTU.

This section examines trends in uninstructed deviations based on two basic measures:

- Volume of Uninstructed Deviations. The total volume or magnitude of all uninstructed deviations on a system-wide level is important since this reflects the impact of uninstructed deviations on the overall quantity of incremental or decremental energy that the CAISO must dispatch to balance system loads and resources. The magnitude of system-level uninstructed deviations was measured by calculating the approximate net deviation in each 10-minute settlement interval of all generating units (including generating units not subject to UDP). The approximate deviation of each unit was first calculated for each interval and the net deviation on a system level of each interval was then calculated by summing up the approximate deviation of all generating units. This summation and netting of individual resource deviations reflected the fact that system and market operation are affected primarily by the net system-wide deviation, rather than deviations of individual resources. Since the system level deviations can be either positive or negative each interval, the system level deviation each interval was converted to an absolute value for purposes of aggregating and comparing the volatility of deviations over longer-term periods (e.g., by month). These values were then averaged to calculate an average net deviation over each month.

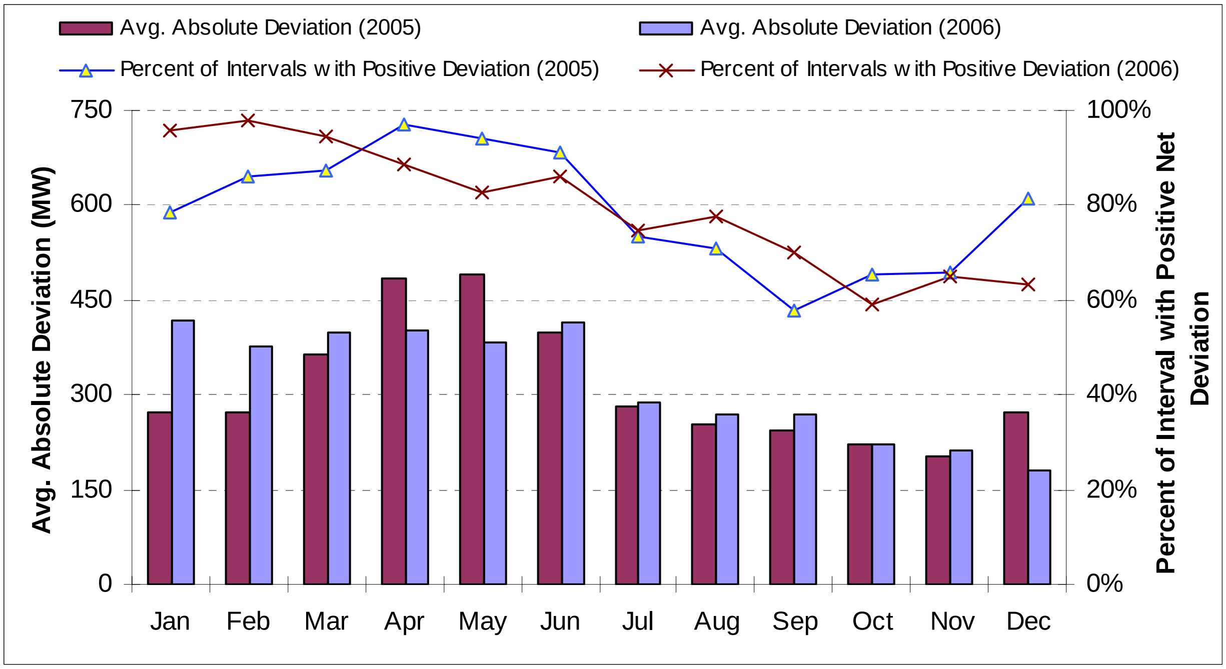
- Volatility of Uninstructed Deviations. The volatility of uninstructed deviations on a system-wide level from one interval to the next is also important since sudden and/or unpredictable changes in system level uninstructed deviations can have detrimental impacts on system and market operations. The volatility of uninstructed deviations was assessed based on the change in system level uninstructed deviations from each interval to the next. Again, since the system level deviations can be either positive or negative each interval, the change in system level deviation in each interval was converted to an absolute value for purposes of aggregating and comparing the volatility of deviations over longer-term periods (e.g., by month). These values were then averaged to calculate an average net between settlement interval deviation over the month.

As the primary concern with uninstructed deviations under the current market design is whether generating units are responding to dispatch instructions to provide interval to interval balancing energy in real-time, the analysis presented in this section was limited to generating units within the control area and did not include deviations of import resources. The settlement interval deviation of each generating unit was based on the unit's uninstructed imbalance energy as calculated by the settlement system. Units providing regulation were excluded from the analysis during the hours they were providing regulation since this energy is provided in response to CAISO operating instructions.

Figure 3.18 compares the magnitude of generating unit uninstructed deviations during 2006 as compared to the corresponding months in 2005.[4] Figure 3.18 also shows the percentage of 10-minute settlement intervals in which the net system level deviation was positive (i.e., net generation exceeded the total amount of energy scheduled or dispatched from these units) during each of these months.

[4] The average generating unit uninstructed deviations shown in Figure 3.18 are an average of the absolute values of the total net generating unit deviations for each 10-minute settlement interval.

Figure 3.18 Average Absolute Value of Net Uninstructed Deviation

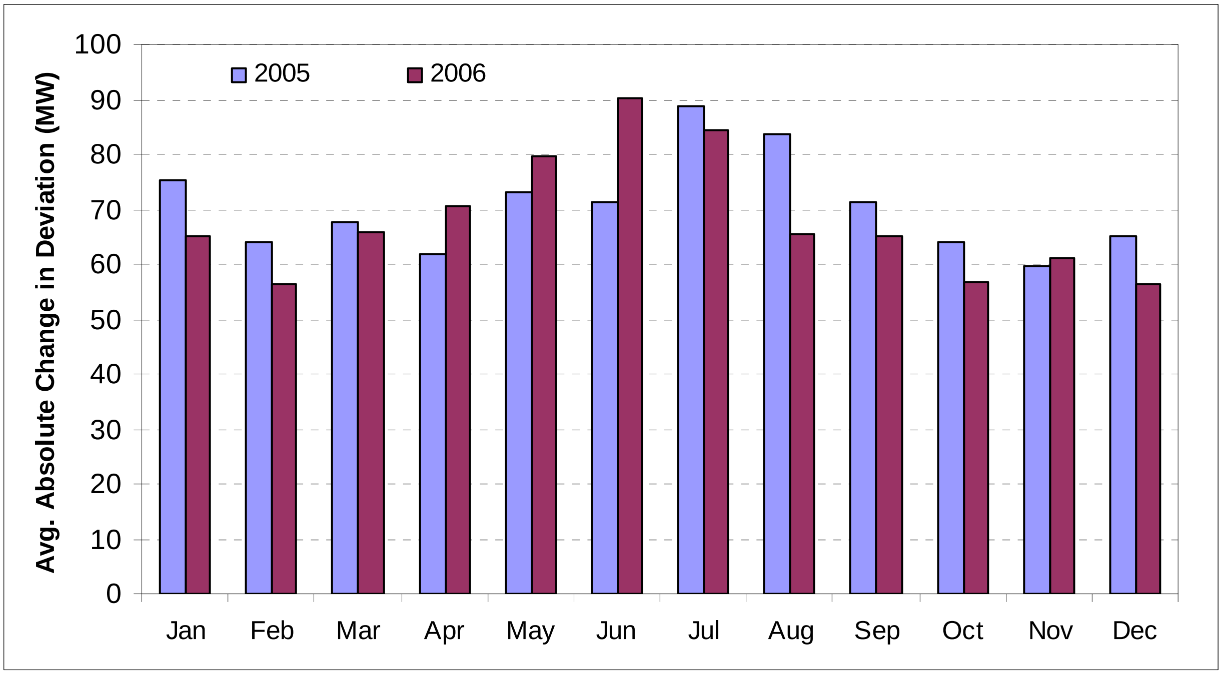


As shown by Figure 3.18, uninstructed deviations in 2006 were consistent with those that existed in 2005 – uninstructed deviations averaged 319 MW in 2006 and 313 MW in 2005. Deviations were slightly greater during January and February 2006 than during those months in 2005, while deviations were slightly less during April, May, and December 2006 than during those months in 2005. These differences were likely due to differences in the timing of runoff conditions affecting hydro units or due to a short-term non-systematic deviation of a single large unit. Both the 2006 and 2005 data appear to show the same seasonal variation, with the magnitude of deviations greater in the spring months, which is likely at least partially attributable to positive deviation of hydro units during the spring runoff period.

Figure 3.18 also shows that uninstructed deviations were predominately positive (i.e., generating more than schedule plus dispatch instructions), consistent with that which occurred in 2005 – the net deviation of generating units was positive in an average of 80 percent of settlement intervals throughout 2006 and in 79 percent of settlement intervals in 2005. The prevalence of positive uninstructed deviations are likely explained by units running uninstructed, energy produced during start-up and shutdown periods, and by units that must run at levels greater than scheduled due to environmental constraints.

Figure 3.19 examines the volatility of uninstructed deviations as represented by the monthly average absolute value of the change in net generating unit deviations between 10-minute settlement intervals for 2006 compared to 2005. As Figure 3.19 shows, the settlement interval to settlement interval change in the net amount of uninstructed deviation in 2006 has been relatively consistent with 2005. The seasonal variation in the between-settlement interval net deviation change is similar in the two periods, as well as the average magnitude of the variation in the two periods, averaging 68 MW in 2006 and 70 MW in 2005.

Figure 3.19 Average Change in Net Uninstructed Deviation between Settlement Intervals



3.4.3 Use of Regulation and Load Bias

The RTMA software implemented in October 2004 was designed to reduce the frequency and degree of dispatcher judgment or intervention required to run the real-time imbalance market. The RTMA software continues to allow for dispatcher adjustments, but focuses dispatcher input primarily on one single input: the *load bias*, which is an optional adjustment that can be entered by the dispatcher to RTMA's internally generated projection of imbalance energy requirements over the next one to two hour period.[5] Thus, use of this load bias feature provides a key direct indicator of the degree of judgment or intervention exercised in running the real-time imbalance market.

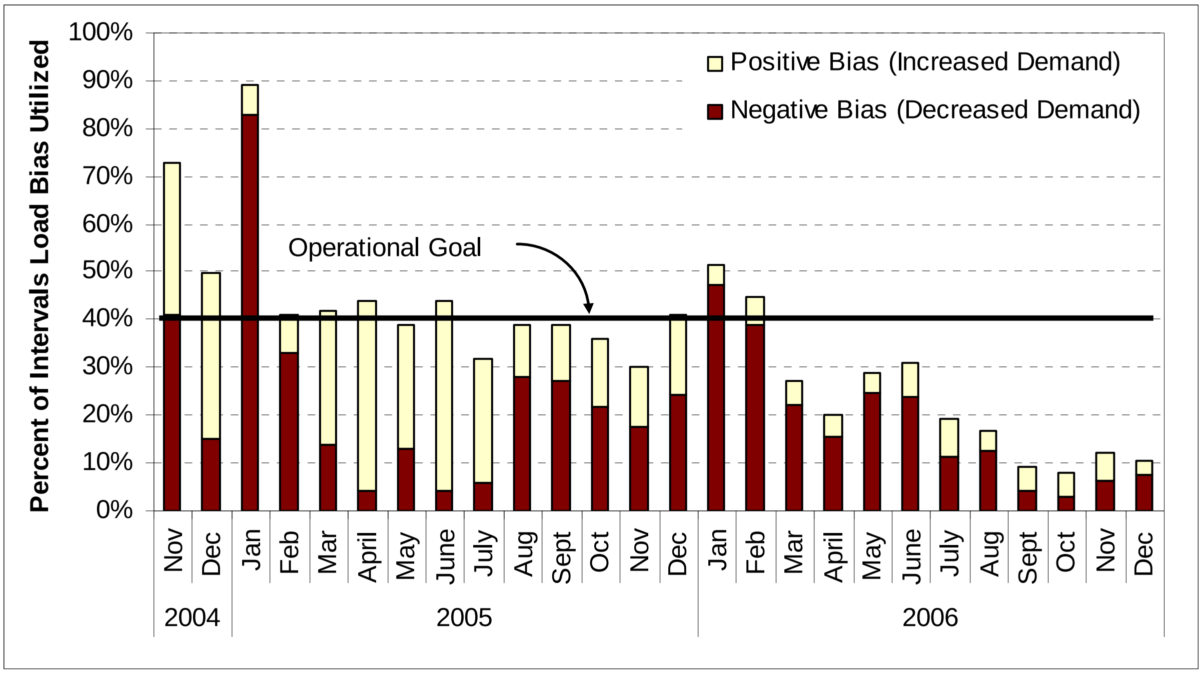
In 2005, CAISO Grid Operations had established an operational goal of utilizing a load bias in the RTMA software in no more than 40 percent of all intervals. As shown in Figure 3.20, while the load bias was utilized from about 30 to 45 percent of intervals during most months of 2005, use of the load bias declined significantly in 2006. Overall, the load bias was utilized during only 23 percent of intervals in 2005 compared to 44 percent in 2006.

As shown in Figure 3.20, the decline in the frequency with which a positive load bias was utilized by Grid Operators was especially pronounced, with a positive load bias utilized during only 5 percent of intervals in 2005 compared to 22 percent in 2006. The infrequent use of a positive load bias is likely due in part to the real-time system conditions that required the CAISO to be decrementing energy throughout most of 2006.

[5] A detailed description of the RTMA software, and how dispatchers utilize the load bias function of RTMA to account for actual system conditions or anticipated conditions within the next few intervals is provided in Chapter 3 of DMM's 2005 Annual Report (see pages 3-1 to 3-2 and 3-30 to 3-31).

As described in last year's annual report, input from Grid Operations staff and analysis of load bias usage patterns by DMM indicates that the load bias is utilized primarily to reduce significant upward or downward deviations from the preferred operating point of resources providing regulation, and thereby maintain ramping capability of regulation capacity. In order to assess the approximate impact of load bias on regulation usage, DMM calculates, for each interval, a counterfactual regulation deviation from POP that may have occurred if load bias had not been used.[6] Figure 3.21 shows summary data for 2005. More detailed and comparative results of this analysis for 2005 and 2006 are shown in Table 3.2.

Figure 3.20 Utilization of Load Bias by Month (Percent of Intervals)



[6] For example, if a 100 MW positive load bias was entered during an interval when the actual regulation deviation was +150 MW, it is assumed that in the absence of the 100 MW positive load bias, 100 MW less of instructed energy would have been dispatched and the regulation deviation would have totaled +250 MW.

Figure 3.21 Estimated Impact of Load Bias on Regulation Energy Usage (2006)

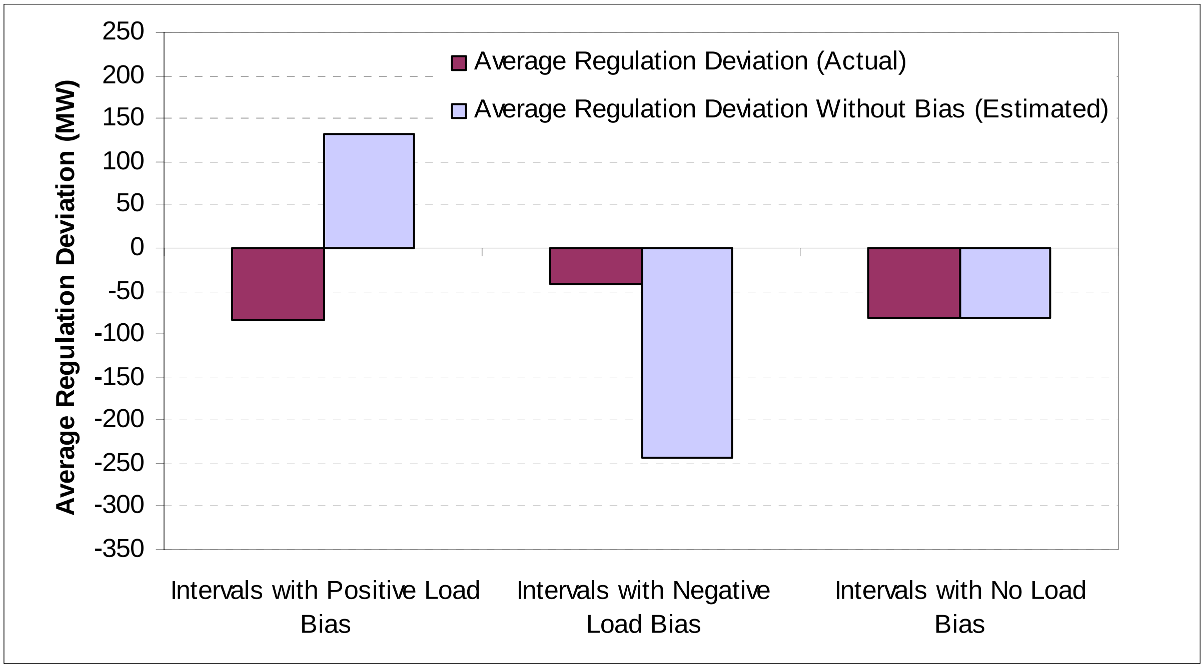


Table 3.2 Estimated Impact of Load Bias on Regulation Energy Usage and Regulation Deviation from POP (2005-2006)

	Type of Load Bias		
	Positive	**Negative**	**None**
Results for 2006			
Percent of 10-minute Intervals	5%	18%	77%
Average Load Bias (MW)	214	-202	0
Average Regulation Deviation (MW)	-83	-41	-81
Average Regulation Deviation (MW) Without Bias	131	-243	
Average Absolute Deviation (MW) from POP	158	117	121
Average Absolute Deviation (MW) from POP Without Bias	194	250	
Average Decrease in Absolute Deviation (MW) from POP due to Bias	35	133	
Results for 2005			
Percent of 10-minute Intervals	22%	20%	58%
Average Load Bias (MW)	229	-255	0
Average Regulation Deviation (MW)	-16	-51	-28
Average Regulation Deviation (MW) Without Bias	212	-306	
Average Absolute Deviation (MW) from POP	126	127	120
Average Absolute Deviation (MW) from POP Without Bias	234	316	
Average Decrease in Absolute Deviation (MW) from POP due to Bias	108	189	

As shown in Table 3.2 and Figure 3.21, the load bias appears to have been used to decrease the usage of regulation capacity relative to levels that would have occurred absent any load adjustments by operators. The actual average regulation deviation during the 23 percent of intervals when a positive or negative load bias was utilized was -83 and -41 MW, respectively, while the actual average regulation deviation during the 77 percent of intervals when no load bias was utilized was -81 MW. However, if no load bias had been utilized during the 18 percent of intervals when a negative load bias was used, the average regulation deviation may have been as high as -243 MW. Meanwhile, if no load bias had been utilized during the 5 percent of intervals when a positive load bias was used, the average regulation deviation may have been +131 MW. As summarized in Table 3.2, this equates to an average reduction in the absolute value of the system level deviation from POP of about 35 MW during interval when a positive load bias was utilized.

Another overall trend in 2006 was decreased usage of upward regulation capacity and increased usage of downward regulation capacity. These trends can be attributed largely to real-time system conditions that required the CAISO to be decrementing energy throughout most of 2006. As shown in Figure 3.22, the portion of intervals when the CAISO was utilizing upward regulation dropped from about 40 percent in 2005 to about 25 percent in 2006. During these intervals, the average amount of upward regulation energy utilized also dropped from about 39 MWh in 2005 to about 24 MWh in 2006, as shown in Figure 3.23. Meanwhile, the portion of intervals when the CAISO was utilizing downward regulation increased from about 60 percent to about 75 percent from 2005 to 2006. During these intervals, the average amount of downward regulation energy also increased from about -72 MWh in 2005 to about -96 MWh in 2006.

Figure 3.22 Regulation Capacity Usage

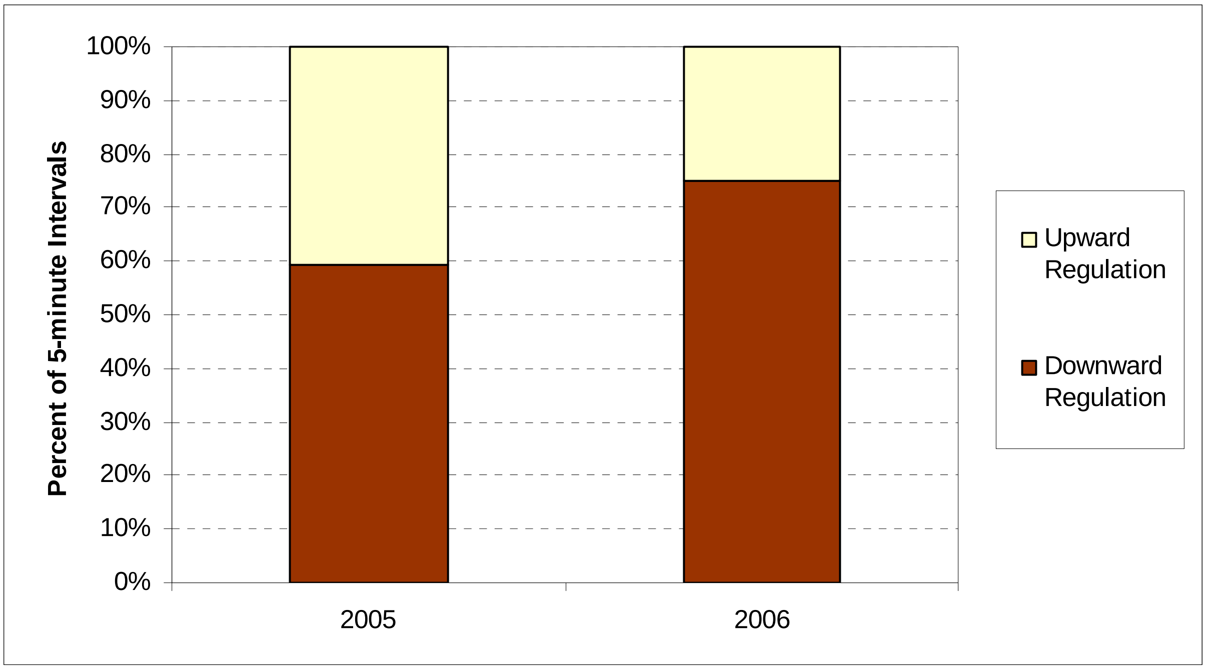
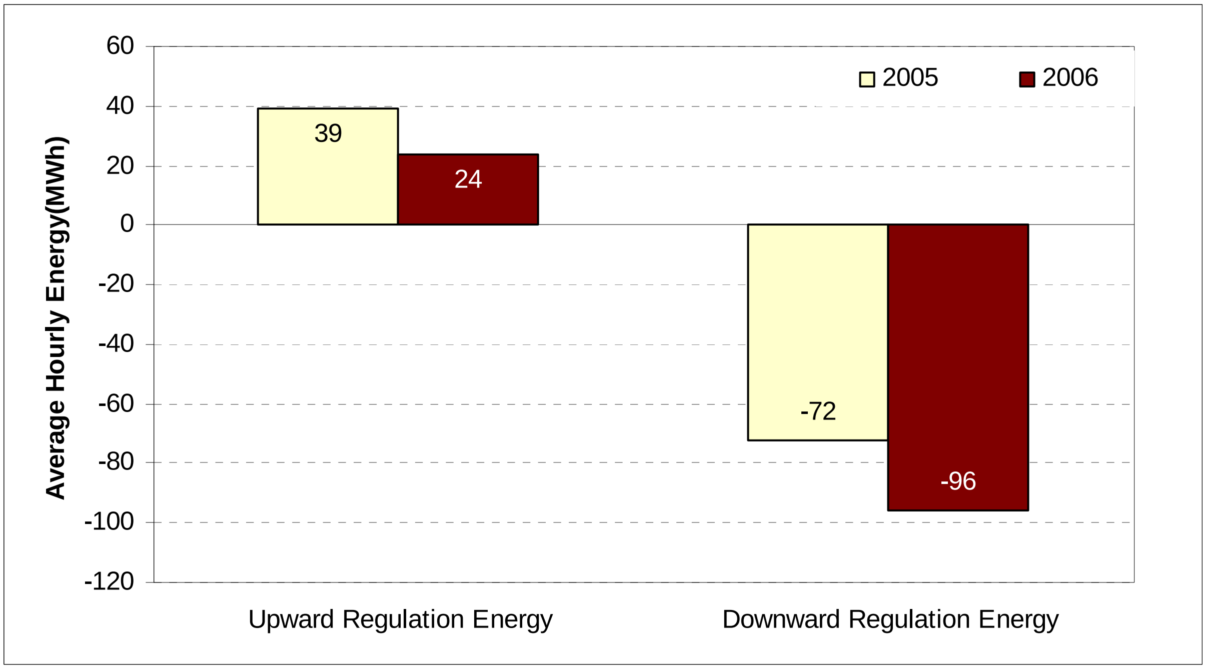


Figure 3.23 Average Hourly Regulation Usage



3.4.4 Price Convergence between Pre-dispatch Imports and Intra-hour Dispatch

Year 2006 is the first complete operating year following the implementation of Amendment 66, which specified that import/export bids from neighboring areas be paid "as-bid" (their bid prices), rather than the better of their bids and prevailing ex-post MCPs.

In the initial RTMA design, two significant modifications were included: a market clearing mechanism, under which bids for incremental energy to provide additional energy at a price lower than decremental bids to purchase energy would be dispatched or "cleared" against each other, and a "bid or better" settlement rule for import/export bids, under which hourly import/export bids pre-dispatched by the CAISO were paid/charged the higher/lower of their bid price or the ex-post MCP subsequently set during the operating hour by resources within the CAISO system dispatched on a 5-minute basis. Although RTMA pre-dispatches import/export bids that were anticipated to be lower/higher than the ex-post MCP, actual system conditions can frequently result in MCPs that are significantly lower/higher than import/export bids pre-dispatched. In early 2005, the combination of these two new market design features resulted in an increasing volume of off-setting import/export bids being cleared in the CAISO markets, and increasing uplift charges being assessed under the "bid or better" settlement rule. In spring 2005, significant divergences were identified between the projected prices used to clear import/export bids and the actual ex-post MCPs.

As a result of the systematic and often excessive uplift charges incurred by off-setting import and export bids pre-dispatched as part of the market clearing feature of RTMA, the CAISO filed Amendment 66 with FERC to replace the "bid or better" settlement rule for pre-dispatched import/export bids to an "as-bid" market design. Under an "as-bid" settlement, pre-dispatched import bids are paid the bid price, while pre-dispatched export bids are charged the bid price. The change to an "as-bid" settlement rule was chosen by the CAISO as a second-best option, with a preferred option being settlement of all pre-dispatched import/export bids at a separate pre-dispatch MCP that would be applied to all hourly import bids pre-dispatched. However, the single price pre-dispatch market option could not be implemented without a significant delay and expenditure of resources.

Once Amendment 66 was implemented, the volume of bids dispatched for market-clearing (beyond bids pre-dispatched for meeting CAISO system imbalance needs) and the associated uplift costs declined dramatically. Through the end of year 2006, significant improvements have been made from Amendment 66 implementation, such as price convergences for pre-dispatched energy to Real Time Market prices, dramatically reduced volume of offsetting incremental and decremental energy, and lowered the net cost for market clearing.

- **Price convergence**. Prior to implementation of Amendment 66, the prices of pre-dispatched incremental energy (including uplifts) were often significantly higher than the values of the incremental energy as reflected in the MCPs set in the CAISO real-time 5-minute imbalance market. Similarly, prior to implementation of Amendment 66, the prices of pre-dispatched decremental energy (including uplifts) tended to be systematically lower than the values of the decremental energy calculated at the ex-post MCPs set in the CAISO real-time 5-minute imbalance market. Since the implementation of Amendment 66, prices for pre-dispatched energy from import/export bids have tracked much more closely with Real Time Market prices set by resources within CAISO system subsequently dispatched within each operating hour. Figure 3.24 and Figure 3.25 show the trend in volumes and net prices of incremental and decremental energy pre-dispatched to balance CAISO system demand, respectively, and compare the net prices for pre-dispatched incremental and decremental energy with the value of this pre-dispatched energy calculated using the corresponding hourly ex-post MCP set by resources dispatched within the CAISO system. As shown in Figure 3.23, since implementation of Amendment 66, prices for pre-dispatched incremental energy generally converge with Real Time Market clearing prices. As illustrated in Figure 3.24, while prices for pre-dispatched and Real Time decremental energy often converge, prices for pre-dispatched decremental energy tends to drop below Real Time Market clearing prices when the CAISO is pre-dispatching high volumes of decremental energy. The need for the CAISO to decrement relatively large volumes in the pre-dispatch process can be caused by several reasons, including as high levels of scheduling or over-scheduling, and various sources of unscheduled energy, which include minimum load energy from units committed through the MOW process, net energy produced from intra-zonal congestion management, and uninstructed energy from resources within the CAISO.

- **Reduced volume of offsetting incremental and decremental energy**. The volume of offsetting incremental and decremental energy bids pre-dispatched by the CAISO to clear the market has also been dramatically reduced under the "as-bid" settlement rule. Since the effective date of Amendment 66 through the end of 2006, an average of only about 25 MW of off-setting incremental and decremental bids have been pre-dispatched each hour, as opposed to an average of about 600 MW per hour in the month prior to implementation of Amendment 66.

- **Lowered cost for market clearing**. Total uplift costs incurred prior to the CAISO's March 23, 2005 filing were estimated at $33.6 million, with about $18.6 million of these uplift costs attributed to clearing of overlapping (or offsetting) incremental and decremental bids under RTMA. Costs attributable to clearing of overlapping (or offsetting) incremental and decremental bids averaged about $400,000 per day in the month prior to Amendment 66. As shown in 0, the cost for offsetting incremental and decremental bids drops dramatically after “as-bid” settlement rule was implemented.

Figure 3.24 Average Hourly Volume of Bids Pre-Dispatched by the CAISO and Average Daily Costs to CAISO of Market Clearing

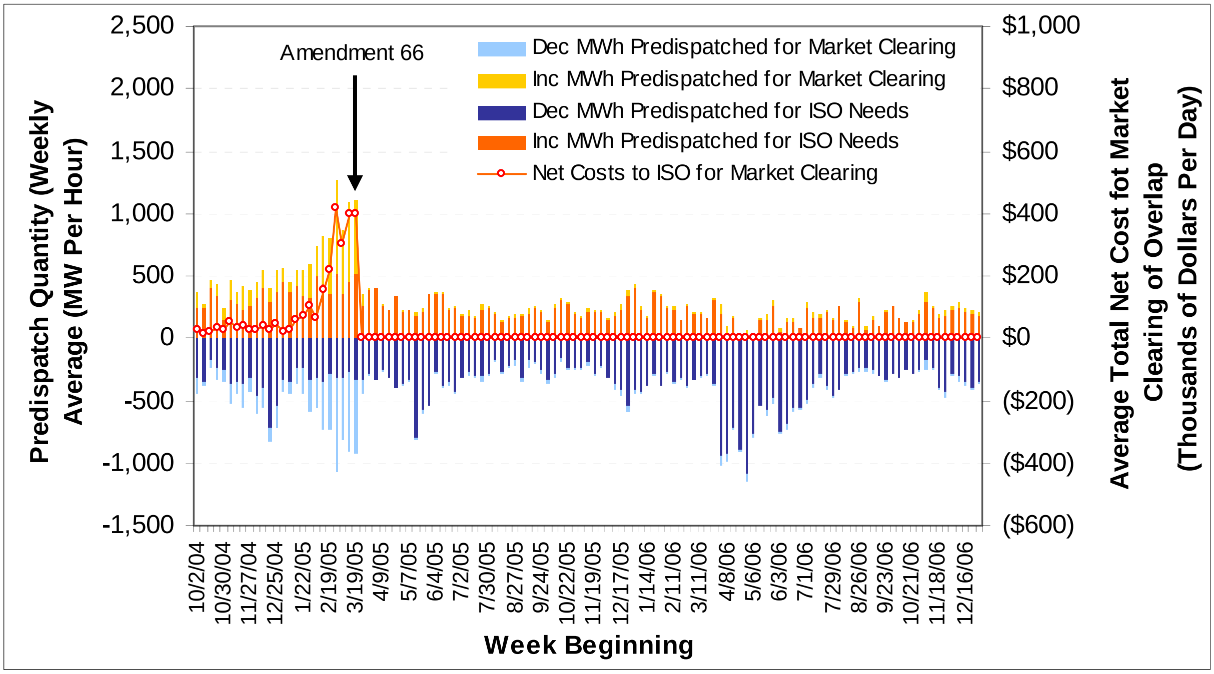


Figure 3.25 Total Net Price Paid for Incremental Energy Pre-dispatched to Balance CAISO System Demand

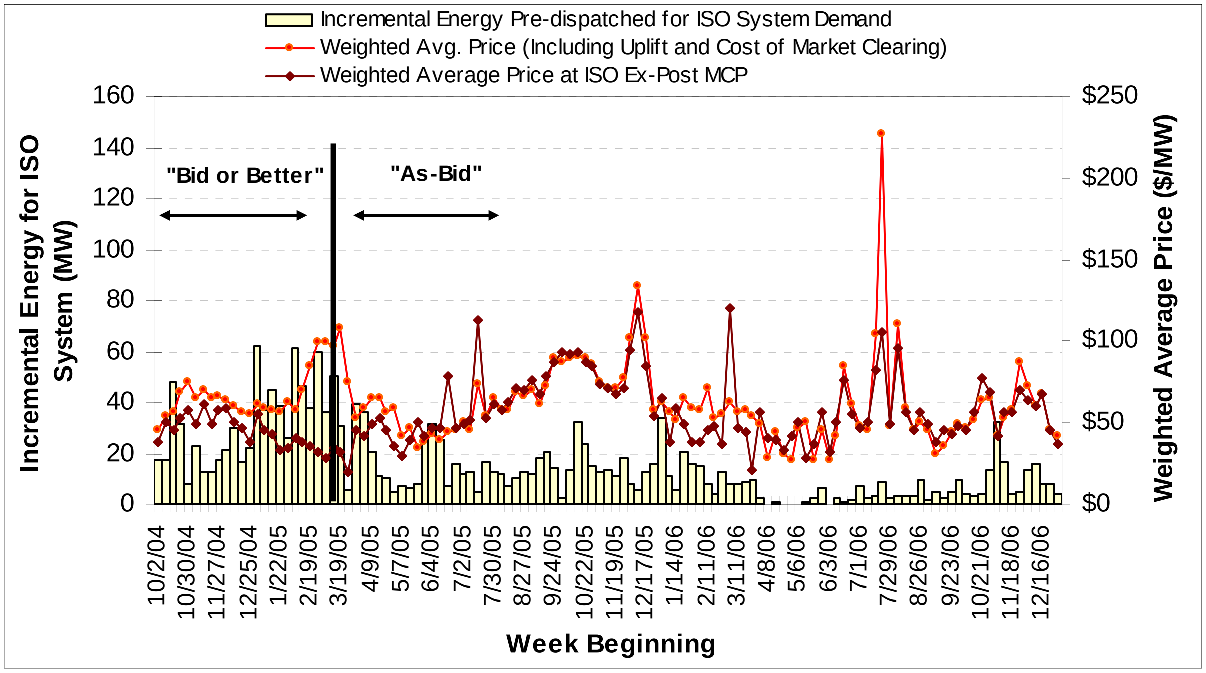
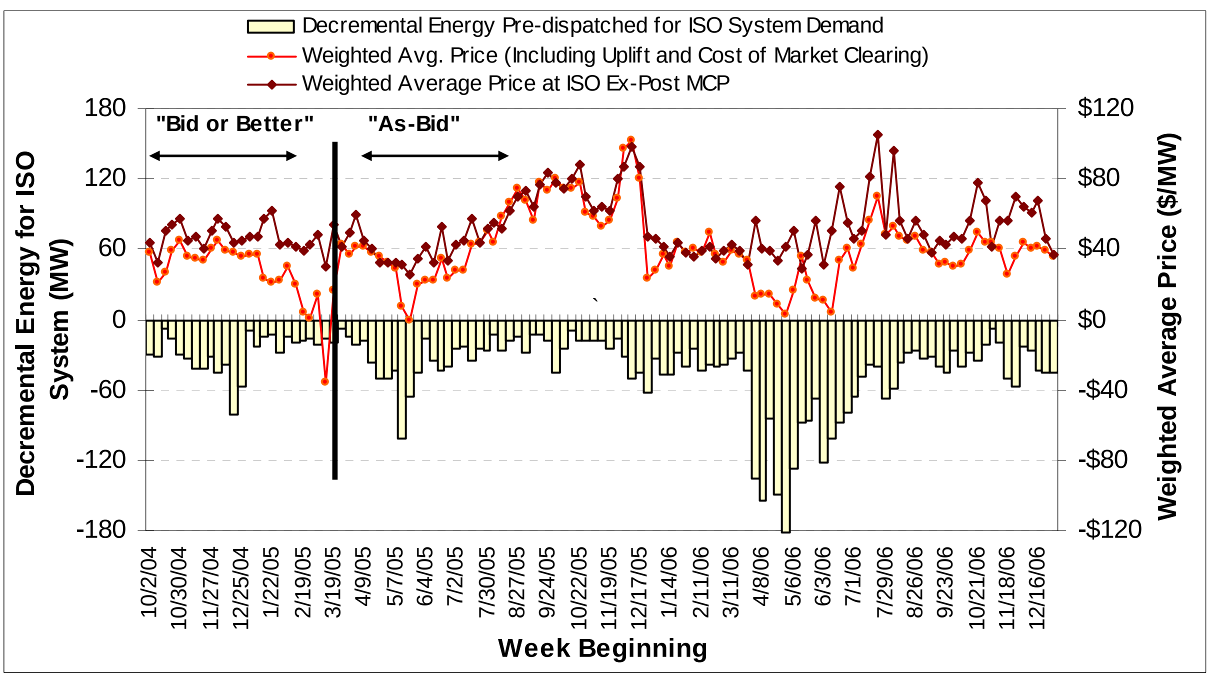


Figure 3.26 Total Net Price Received for Decremental Energy Pre-dispatched to Balance CAISO System Demand



The replacement of the "bid or better" settlement rule with an "as-bid" settlement rule for imports/export created a concern among some market participants that this change would reduce the liquidity of import/export bids submitted to the CAISO market. To date, however, the CAISO has not experienced problems in terms of bid insufficiency or liquidity of incremental energy import bids since the switch to an "as-bid" market under Amendment 66. In fact, the volume of incremental energy bids has typically been higher in 2006 than during the comparable period in 2004, and has consistently been well in excess of the quantity of bids actually pre-dispatched.

As shown in Figure 3.26, the volume of overall net imports scheduled or bid into the CAISO system remained comparable to pre-Amendment 66 levels throughout the summer months under the "as-bid" settlement rule. The volume of incremental real-time energy bids remained far in excess of amounts of imports actually pre-dispatched. Similarly, as shown in Figure 3.27, the volume of decremental real-time energy export bids submitted to the CAISO Real Time Market increased and remained far in excess of amounts of imports actually pre-dispatched for most hours.

Figure 3.27 Net Scheduled Imports, Real-Time Energy Import Bid Volumes, and Pre-Dispatched Imports - Hourly Averages by Week (Peak Hours 13-20)

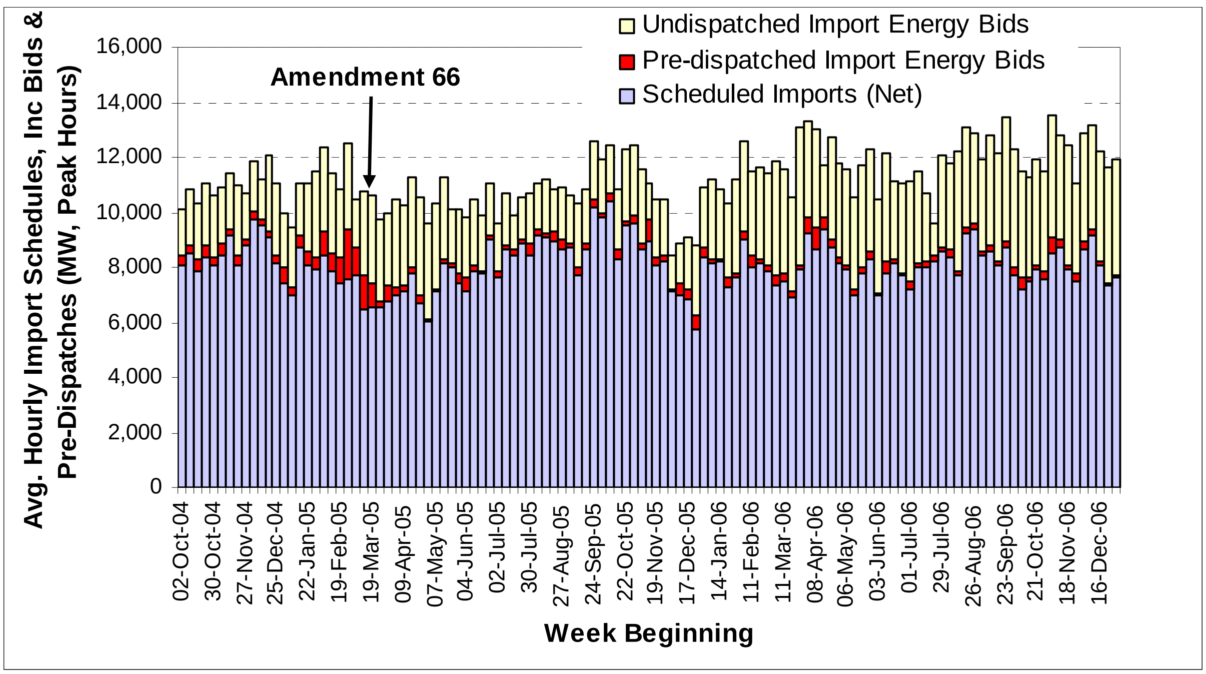
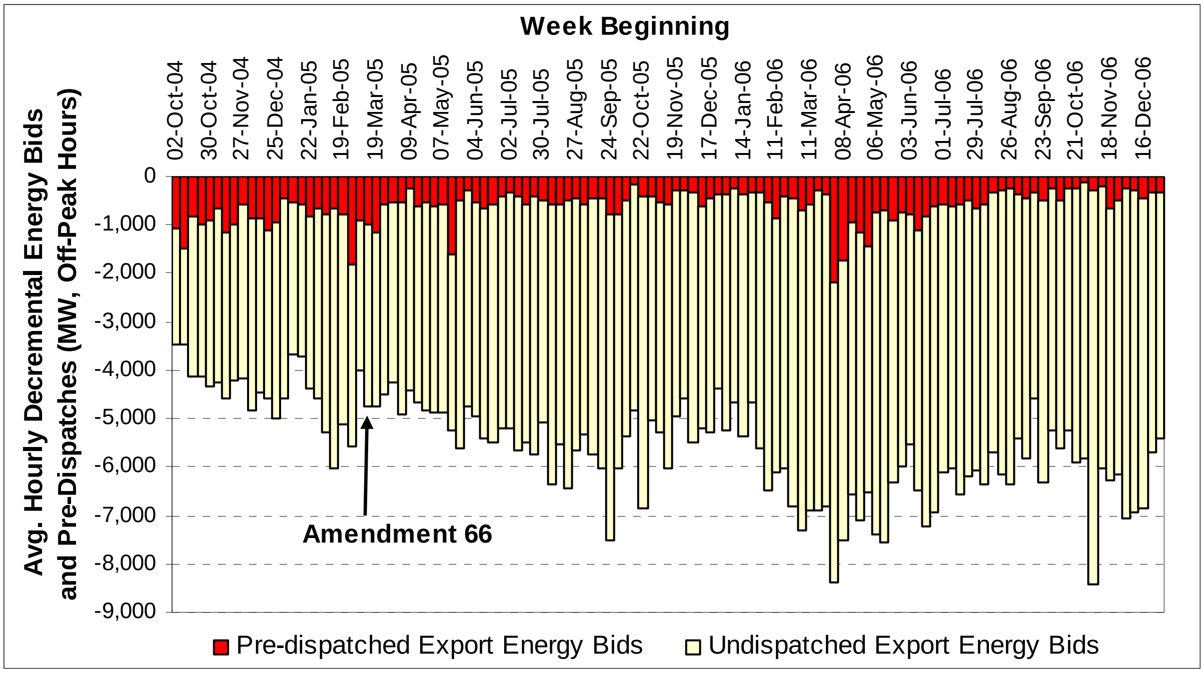


Figure 3.28 Real-Time Energy Export Bid Volumes And Pre-Dispatched Exports - Hourly Averages by Week (Off-Peak Hours 1-8)



4 Ancillary Service Markets

4.1 Summary of Performance in 2006

Overall, average Ancillary Service (A/S) prices increased by 4 percent in 2006 compared to prevailing prices in 2005. The total procurement cost increased by 3 percent while the total procurement volumes of the four types of A/S products stayed almost at the same level as they were in 2005. The increase in the aggregate A/S price resulted primarily from price increases in Non-Spinning Reserve markets, despite a small drop in Regulation-Up Reserve. The average prices of Spinning Reserve and Regulation Down Reserve stayed flat compared with last year.

The A/S markets experienced a significant decline in hours of bid insufficiency in 2006 compared to 2005; however, bid insufficiency was highly concentrated in April and July of 2006 due to system conditions that resulted in relatively high frequency of price spikes during those months. The majority of hours with bid insufficiency in the Regulating Reserves market in 2006 occurred in April and can be attributed to the record high hydroelectric production during the spring months. The high frequency of bid insufficiency in the Operating Reserve markets in July can be attributed to tight supply conditions and high opportunity costs during periods of record-setting loads during the heat wave.

4.2 Ancillary Services Market Background

The CAISO procures Regulation Reserve, Spinning Reserve and Non-Spinning Reserve in the Day Ahead and Hour Ahead Markets such that the total procurement volumes plus self-provision volumes meet or exceed the Western Electricity Coordinating Council's (WECC) Minimum Operating Reliability Criteria (MORC) and North American Electricity Reliability Council (NERC) Control Performance Standards (CPS). The CAISO procures A/S at the lowest overall cost while maintaining the reliability of the system and the competitiveness of the markets. The combination of a single-price auction pricing mechanism across the control area and the Rational Buyer algorithm which allows for economic substitution of less expensive bids in place of more expensive bids across services facilitates a least-cost procurement approach to meeting reliability requirements.

The definitions for the actively procured Ancillary Services are:

1) Regulation Reserves: Reserved capacity provided by generating resources that are running and synchronized with the CAISO controlled grid, so that the operating levels can be increased (incremented) or decreased (decremented) instantly through Automatic Generation Control (AGC) to allow continuous balance between generating resources and demand. The CAISO operates two distinct capacity markets for this service, upward and downward Regulation Reserve.

2) Spinning Reserves: Reserved capacity provided by generating resources that are running (i.e., "spinning") with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours.

The CAISO needs Spinning Reserve to maintain system frequency stability during emergency operating conditions and unanticipated variations in load.

3) Non-Spinning Reserves: Generally, reserved capacity provided by generating resources that are available but not running. These generating resources must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least two hours. Curtailable demand can also supply Non-Spinning Reserve provided that it is telemetered and capable of receiving dispatch instructions and performing accordingly within 10 minutes. The CAISO needs Non-Spinning Reserve to maintain system frequency stability during emergency conditions.

CAISO market participants can self-provide any or all of these A/S products, bid them into the CAISO markets, or purchase them from the CAISO. The CAISO procures two other ancillary services on a long-term basis: voltage support and black start. Reliability Must Run (RMR) contracts serve as the primary procurement vehicle for these services. Through the remainder of this chapter, the term “ancillary services” (A/S) will be used only to refer to the three reserved-capacity products defined above.

Scheduling Coordinators (SCs) simultaneously submit bids to supply any or all three products to the CAISO in conjunction with their preferred day-ahead and hour-ahead schedules. Submitted A/S bids must be associated with specific resources (system generating units, import interchange location, load, or curtailable export) and must contain a capacity component and an energy component. The CAISO selects resources to provide A/S capacity based only on their capacity bid prices and deliverability. Thereafter, the CAISO uses the energy bid prices to dispatch units to provide real-time energy.

4.3 Increase in Ancillary Service Bid Cap

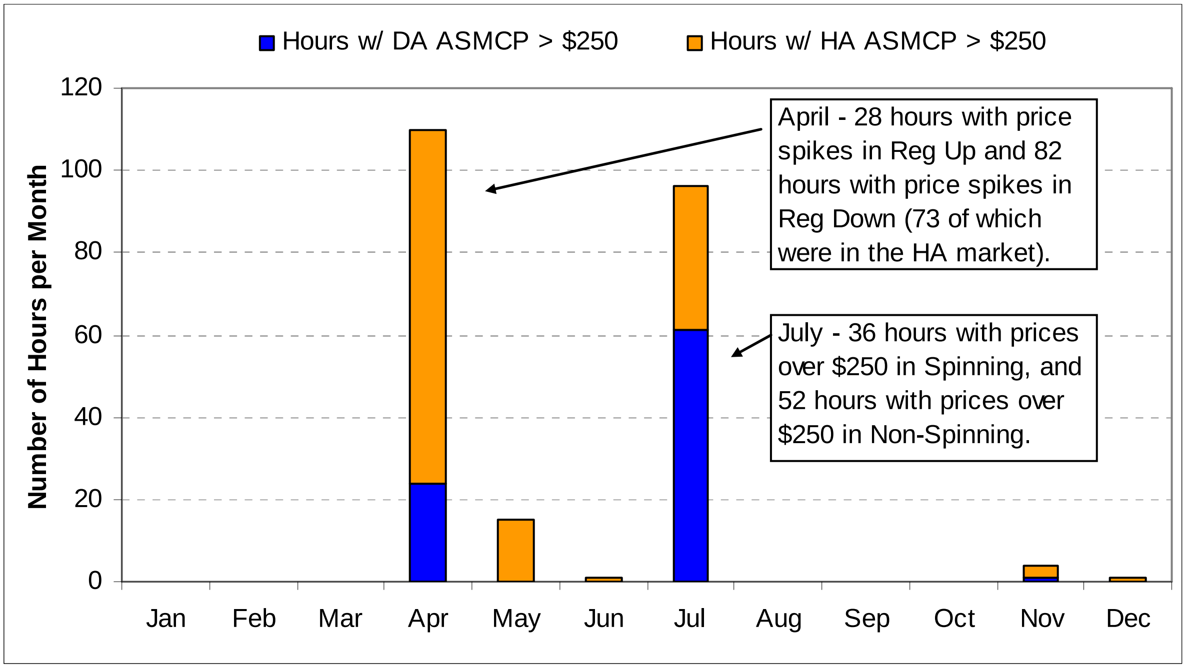
4.3.1 Background

As discussed in Chapter 1, on December 21, 2005, the CAISO submitted a filing to FERC to change the soft bid cap for Real Time Energy from $250/MWh to $400/MWh to alleviate concerns that increasing natural gas prices during the fourth quarter of 2005 may limit suppliers’ willingness to bid into the CAISO Real Time Market. In its filing, the CAISO did not propose to increase the bid cap for ancillary services, which at the time was $250/MW. The proposal to raise the energy bid cap was overwhelmingly supported by industry participants, and was approved by FERC on January 13, 2006[1] (January 13 Order) to be effective the following day. The January 13 Order also instituted an investigation into the price cap in the WECC outside the CAISO and the ancillary service capacity bid cap in the CAISO Ancillary Services Market. After receiving comments, FERC issued an order on February 13, 2006 establishing a $400/MWh “soft” price cap in the WECC (outside the CAISO) and establishing a $400/MW “soft” bid cap for ancillary services bids in the CAISO market. The changes became effective upon issuance of the February 13 Order. Since this increase took effect, the Ancillary Service markets have experienced periods of prices in excess of $250/MW, primarily concentrated in the Regulation

[1] Federal Energy Regulatory Commission, “Order accepting and modifying tariff filing and instituting a section 206 Proceeding,” issued January 13, 2006, 114 FERC ¶ 61,026.

markets in April due to high spring hydroelectric output and the Operating Reserve markets in July due to extreme peak load conditions.

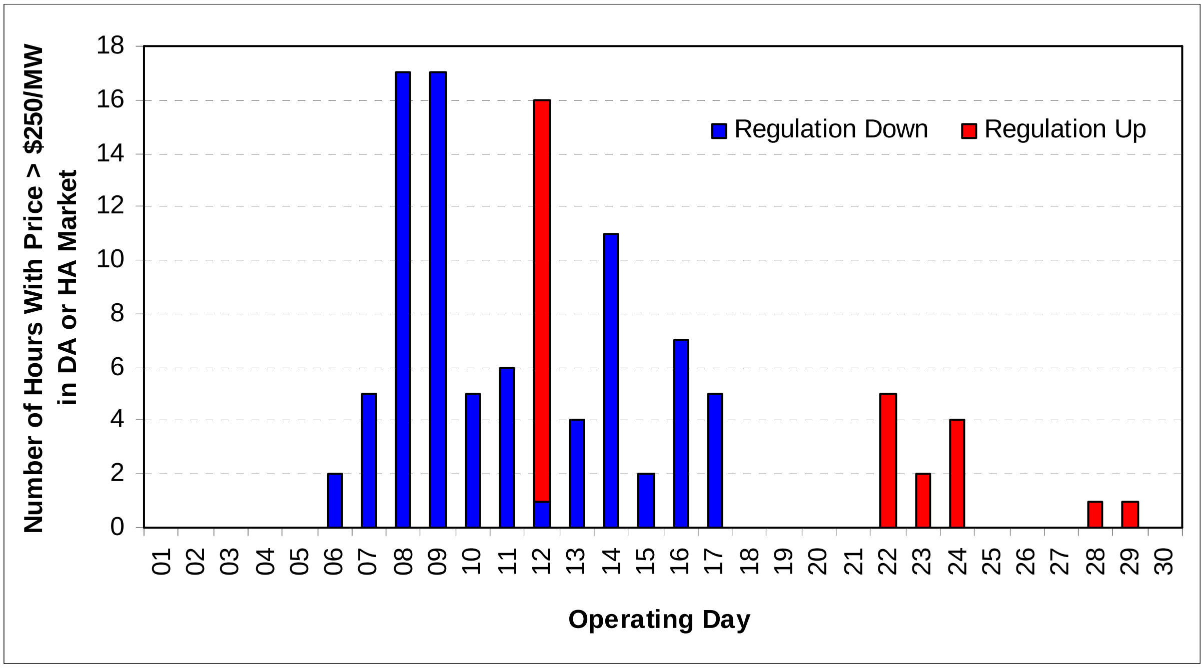
Figure 4.1 Frequency of Ancillary Service Prices Greater than $250/MW



4.3.2 Regulation Reserve Prices over $250/MW

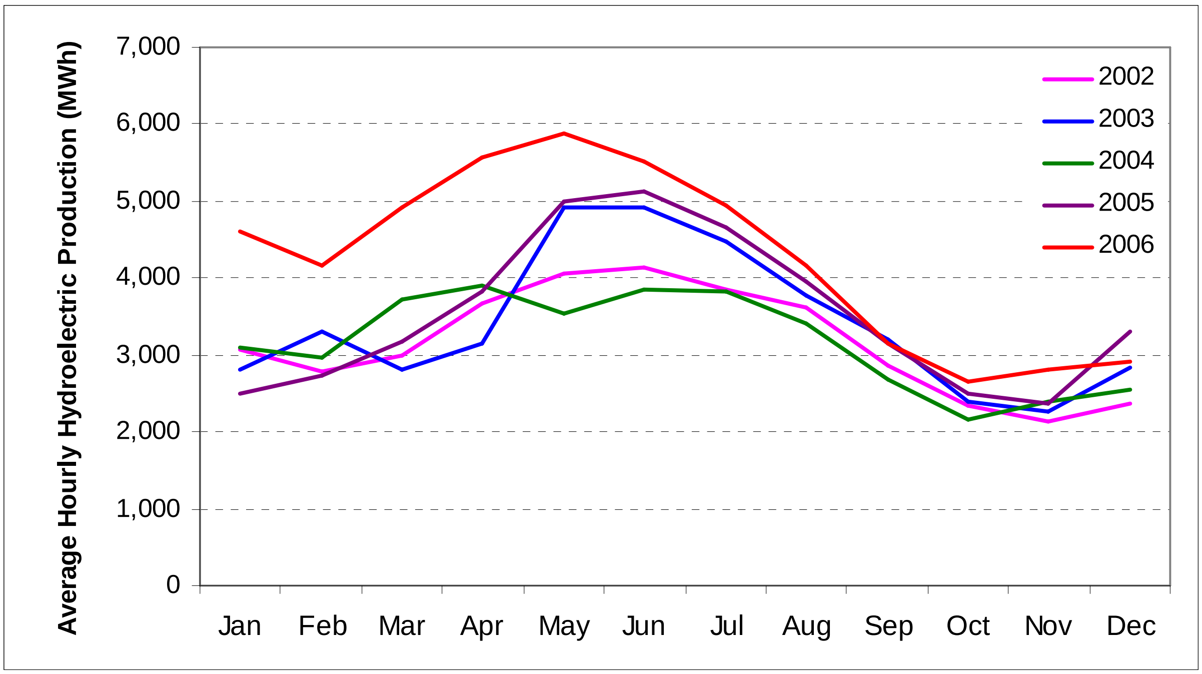
During the winter months of 2006, market clearing prices for ancillary services (A/S) exhibited a steady increase in each market, except for Non-Spinning Reserves. In late March and April, prices for regulating reserves increased significantly from prior price levels, moving into the price region between the prior bid cap of $250/MW and the current bid cap of $400/MW while prices in the Spinning Reserve markets remained well below the $100/MW mark and prices for Non-Spinning Reserve during this period remained below $30/MW.

Figure 4.2 Majority of Regulating Reserve Price Spikes in April



The winter and early spring periods in 2006 were extremely wet and warm, causing swelling river and reservoir levels. This weather pattern and the resulting increased river flows resulted in increased generation from hydroelectric resources throughout the West. Under these conditions, hydro resources experience a "spill" state such that, if they did not generate, they would be forced to spill water without generating electricity, which is viewed as wasted water. Consequently, these resources often generate at full capacity, as the energy markets provide the final opportunity to capture value for the water behind the dam.

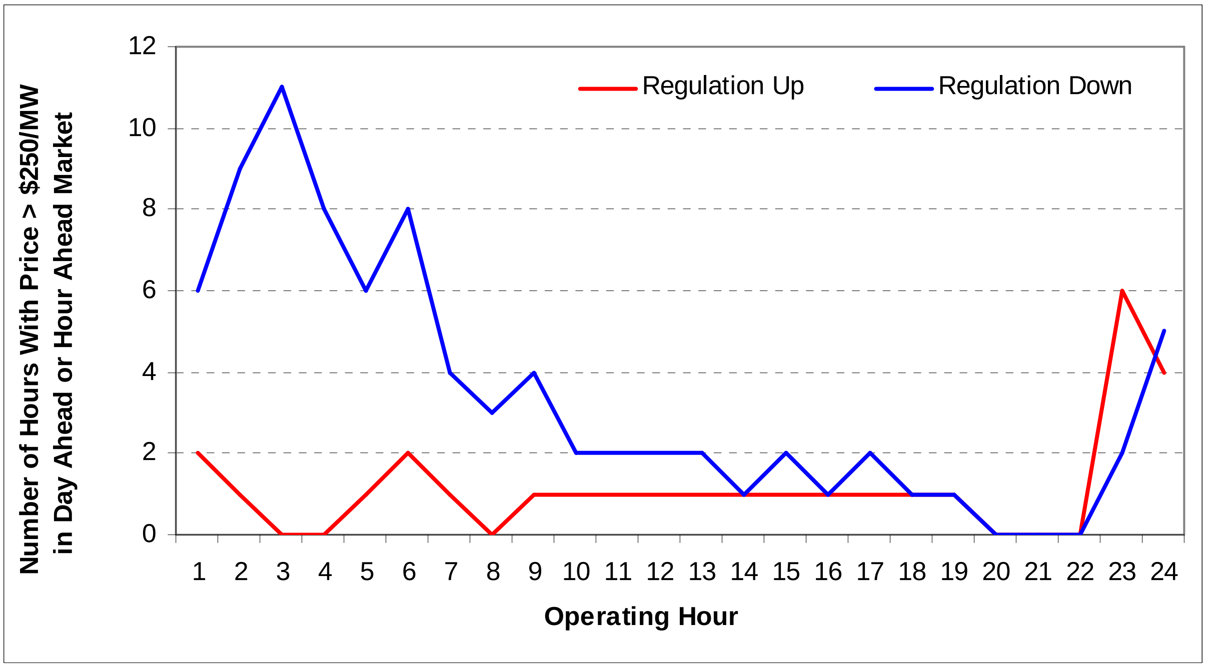
Figure 4.3 Hydroelectric Output for 2002 - 2006



Such strong hydro-electric conditions stress A/S markets, particularly those that require on-line resources. This is because hydro-electric resources can be producing near their limit, reducing the availability of Regulation Up Reserve capacity available. Also, they are reluctant to reduce output due to the spill conditions that accompany high rain and runoff periods, thus reducing the availability of Regulation Down Reserve capacity. Figure 4.3 above shows the high hydro output experienced in the months of January through June compared to prior years.

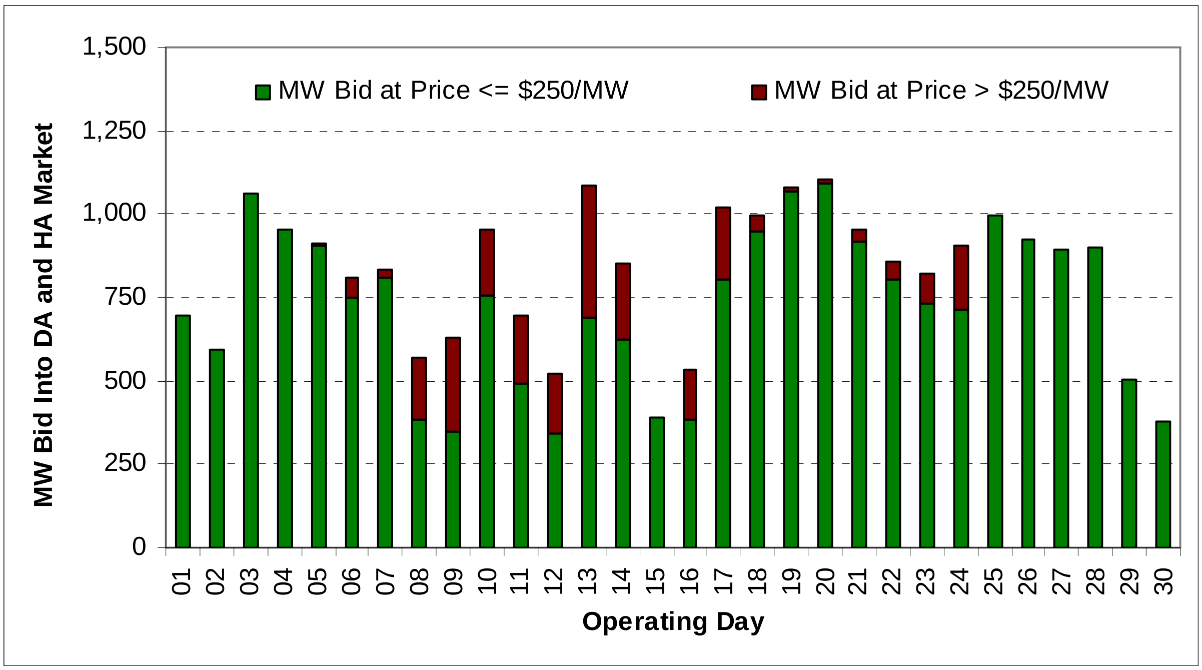
Daily load patterns also affect prices in these markets, as fewer resources are online and operating at a level at which they can provide regulating reserves during off-peak hours. Consequently, price spikes are more prevalent during the off-peak hours of the day. Figure 4.4 displays the price-spike profiles for each of the regulation markets in the month of April. Late evening and early morning hours compound the seasonal factors and results in a higher frequency of price spikes, as generation that had been on-line to meet the daily peak ramps down or shuts off.

Figure 4.4 Hourly Frequency of Regulating Reserve Prices Over $250/MW in April



As profit margins in Ancillary Service markets increase with price increases we expect to see some market response in terms of additional bids in the higher-priced services. The price spikes in the Regulation Reserve markets were fairly concentrated in the first half of April and, as seen in Figure 4.5 below, there was some measurable supply response to these spikes as suppliers bid in more capacity priced below $250/MW. Once additional, lower-priced supply bids began entering the market, the incidence of price spikes diminished and prices in the Regulating Reserve markets declined.

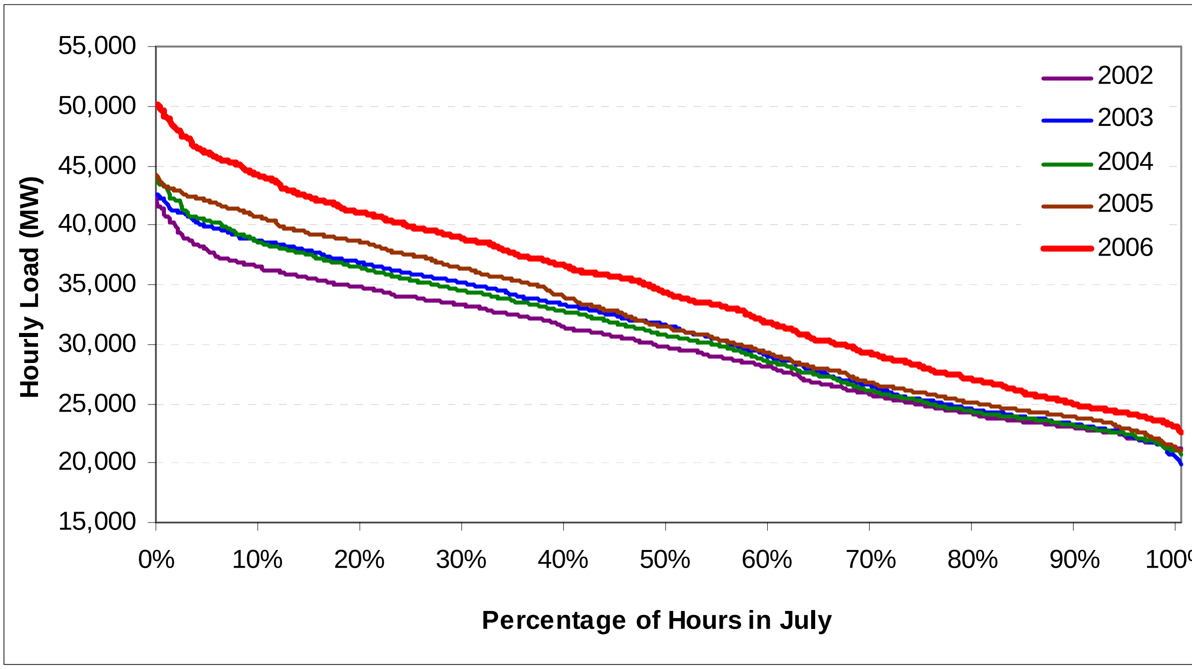
Figure 4.5 Supply Response to April Regulating Reserve Price Signals



4.3.3 Operating Reserve Prices over $250/MW

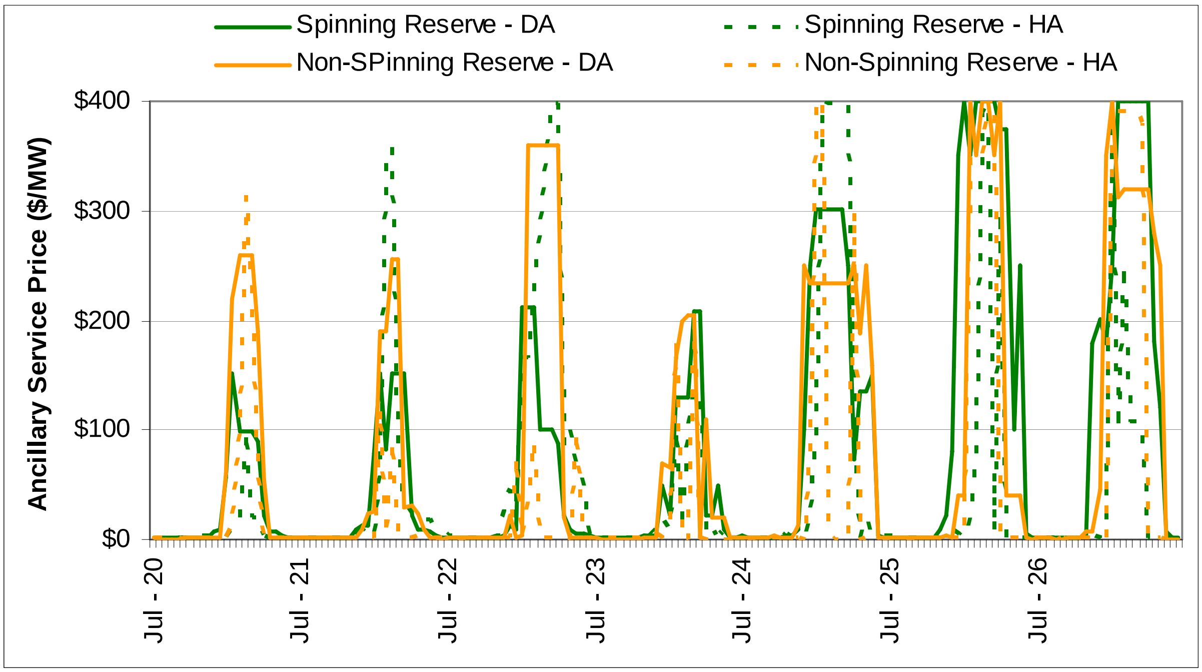
In July the west coast experienced a heat wave that resulted in peak load records being set on consecutive days. As seen in the load duration curves shown in Figure 4.6 below, loads in July of 2006, particularly peak loads, were considerably higher than in prior years.

Figure 4.6 Hourly Load Duration Curves for the Month of July (2002 – 2006)



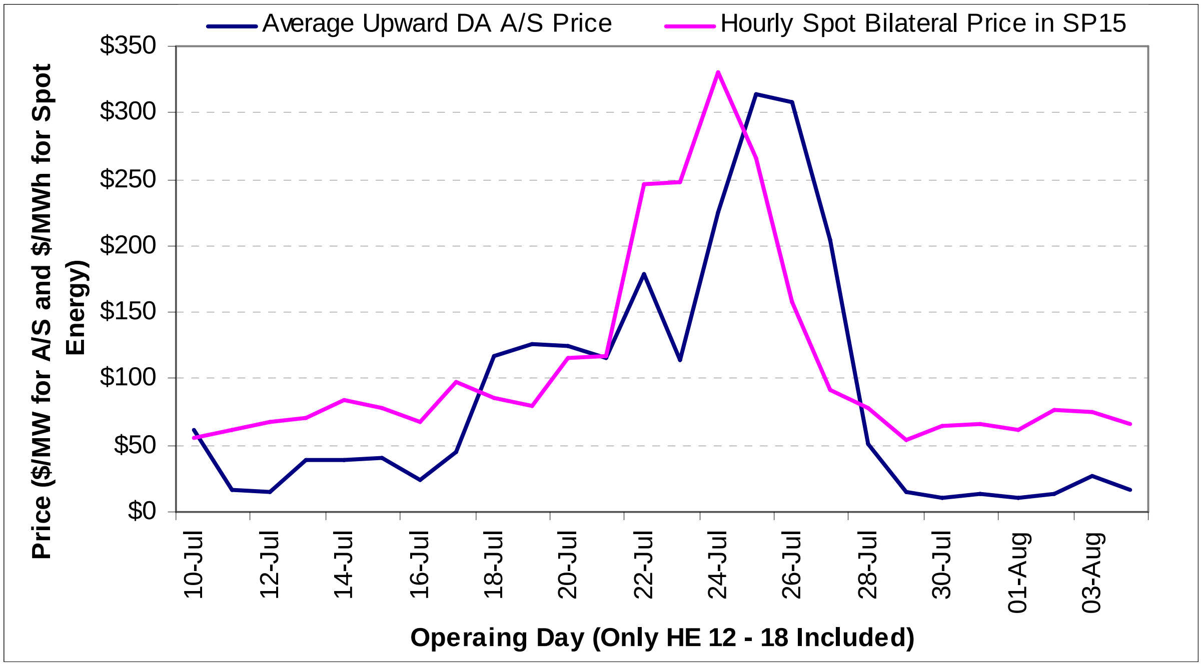
During the crest of the July heat wave (roughly from July 21 – 26) Grid Operators were faced with increasing frequency of bid insufficiency in the Operating Reserves (Spinning Reserve and Non-Spinning Reserve) and market prices for those services were significantly higher during the heat wave as seen in Figure 4.7 below. Unlike the price spikes in the Regulation markets that were seen primarily during the off-peak hours, prices in the Operating Reserve markets (both Day Ahead and Hour Ahead) were higher primarily when online capacity was most scarce, during hours ending 12 through 18.

Figure 4.7 Operating Reserve Prices During the July Heat Wave



Though the CAISO Real Time Market prices were not well correlated with spot bilateral prices during extreme peak periods, Day Ahead Ancillary Service Market prices were. Thus the Day Ahead A/S prices reflected the opportunity cost of holding capacity in reserve as opposed to selling energy in the spot market, or the expectation of being held in reserve (not selling energy) when real-time prices are expected to be high. Figure 4.8 shows the correlation between upward Ancillary Service prices and day-ahead spot bilateral energy prices during the July heat wave.

Figure 4.8 Day Ahead Upward Ancillary Service Average Price and Hourly Spot Bilateral Price for July 20 - 26, 2006



Despite the higher prices for upward Ancillary Services, the CAISO did experience significant procurement shortages across the peak load days from July 21 – 26. (More detail on bid insufficiency is included later in this chapter beginning on Page 4.24.) During this time, both Spinning Reserve and Non-spinning Reserve experienced high levels of procurement shortages across the super-peak hours of HE 12 - 18. During periods of bid insufficiency, average prices for Operating Reserves were considerably higher, as seen in Figure 4.9.

Figure 4.9 Average Price of Operating Reserves with and without Bid Sufficiency (July 16 – 31 2006, Hours Ending 12 – 18)

4.4 Prices and Volumes of Ancillary Services

Overall, A/S prices increased 4 percent from a weighted average price of $10.72/MW in 2005 to $11.12/MW in 2006. The overall price increase tracked increases of roughly 50 percent for Non-Spinning Reserve, however, the level of average prices remained below $6/MW. Upward Regulation prices dropped 10 percent, while Spinning Reserve prices and Downward Regulation prices remained almost the same as last year.

Procurement volumes, in total, were essentially unchanged from 2005. The average volumes of all four types of procurements remained at the same level as last year. Table 4.1 compares prices and volumes from previous operating years.

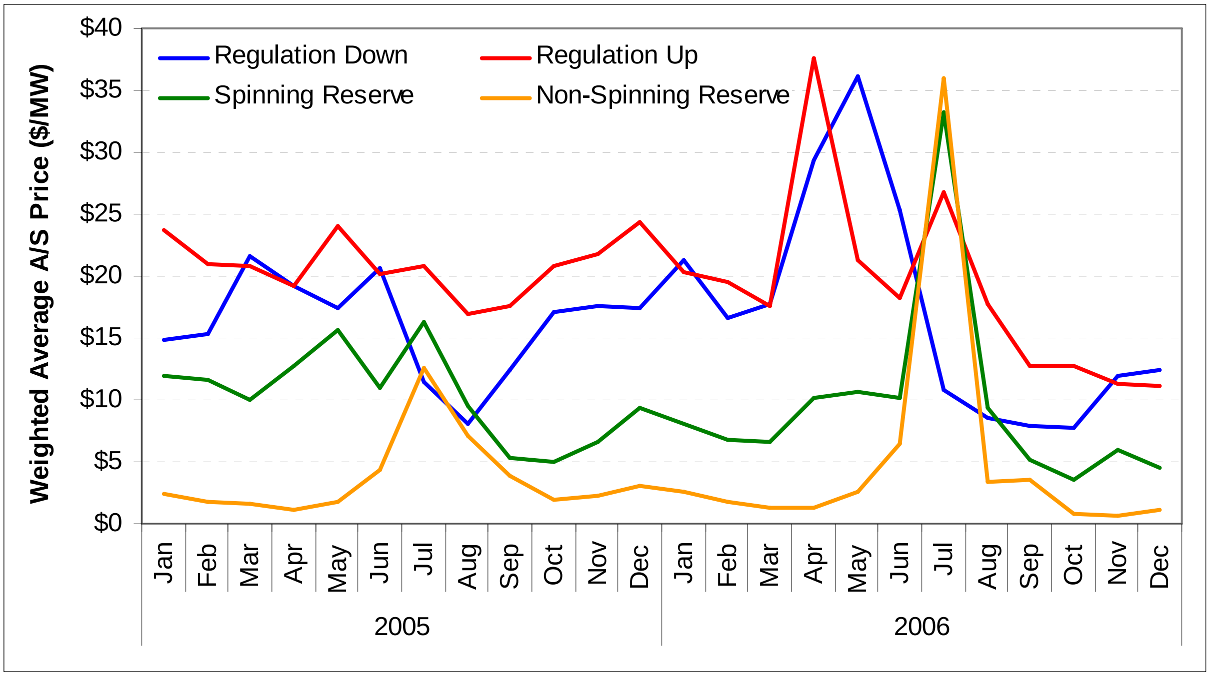
Table 4.1 Annual Hourly Average A/S Prices and Volumes

	Year	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	Average A/S Price
Price ($/MW)	1999	$20.84	$20.22	$7.07	$4.35	$11.97
	2000	$50.15	$77.28	$44.07	$32.46	$41.03
	2001	$42.33	$66.72	$34.69	$30.03	$36.42
	2002	$13.76	$13.41	$4.66	$2.15	$7.08
	2003	$18.43	$18.08	$6.62	$4.20	$9.81
	2004	$10.95	$17.95	$7.25	$4.43	$8.63
	2005	$16.05	$20.94	$10.45	$3.98	$10.72
	2006	$17.01	$18.94	$10.11	$5.96	$11.12

	Year	Regulation Down	Regulation Up	Spinning Reserve	Non-Spinning Reserve	Total Volume
Volume (MW)	1999	769	903	942	735	3,349
	2000	594	633	818	861	2,907
	2001	614	492	1,148	862	3,117
	2002	469	460	775	763	2,466
	2003	416	381	767	722	2,286
	2004	408	395	817	782	2,403
	2005	363	386	841	839	2,428
	2006	354	389	831	831	2,405

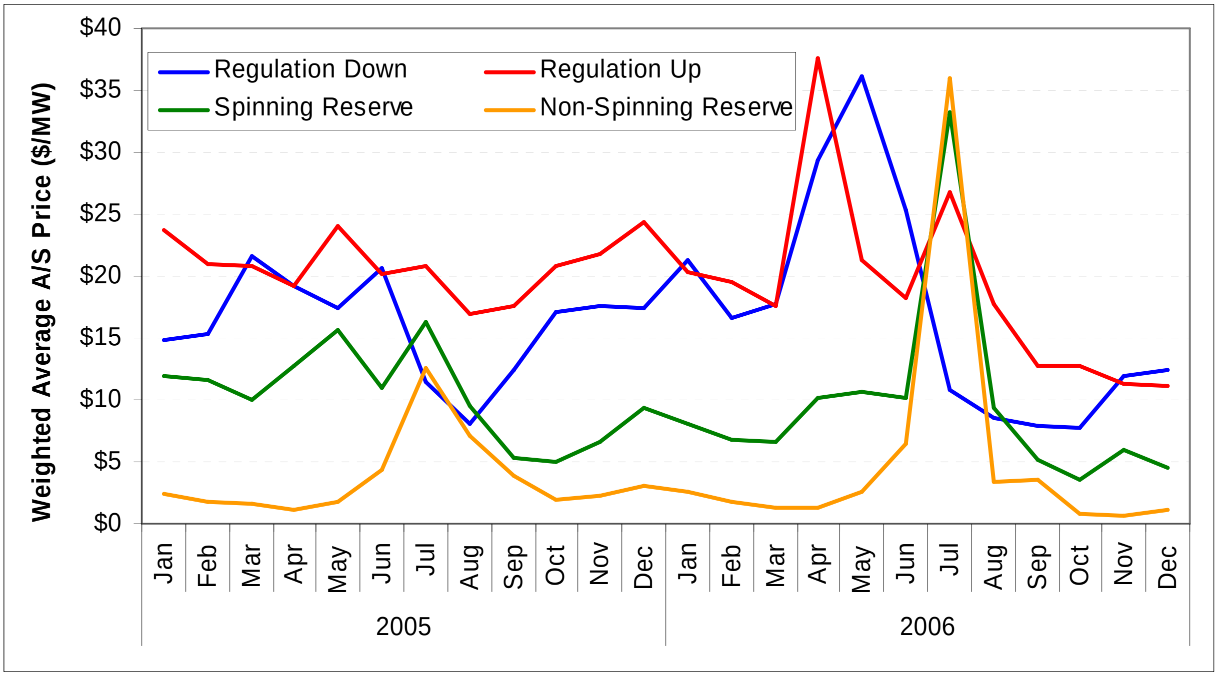
Figure 4.10 depicts the historical pattern of prices and volumes since 1999 and indicates that A/S prices and volumes have been relatively stable over the past five years (2002-2006) as compared to the period from 1999 to 2001.

Figure 4.10 Annual Hourly Average A/S Prices and Volumes



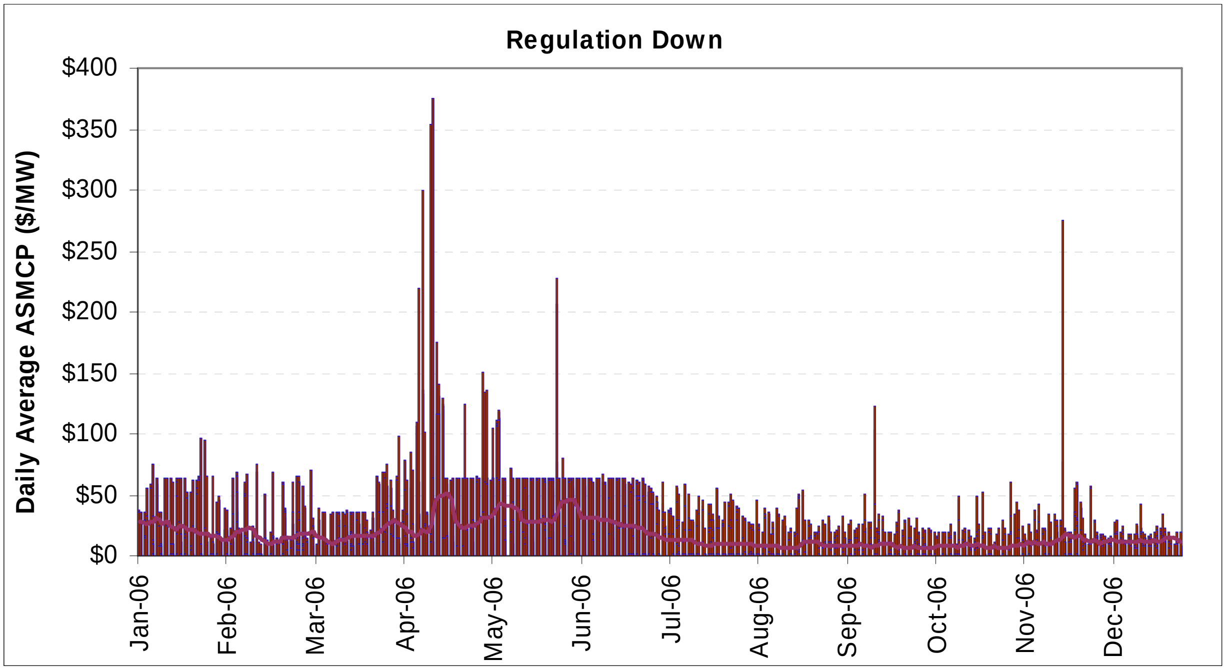
Hourly day-ahead reserve prices do tend to vary with system load levels and seasonal effects on generation as seen in Figure 4.11. As discussed in the previous section, high prices for Regulation Reserves occurred, though largely confined to the spring months. High price levels for Non-Spinning Reserves and Spinning Reserves rose dramatically and occurred primarily during the unprecedented loads seen during the July heat wave.

Figure 4.11 Monthly Weighted Average A/S Prices



Hourly day-ahead prices are shown in Figure 4.12 and Figure 4.13 along with seven-day moving averages showing the trend of prices, by service, across the year. The impact of spring hydro-electric runoff and summer peak load conditions can easily be seen in the pricing trends for Regulating and Operating Reserves in these figures.

Figure 4.12 Day Ahead Regulation Reserve Market Clearing Prices (A/S MCPs) with Seven Day Moving Averages



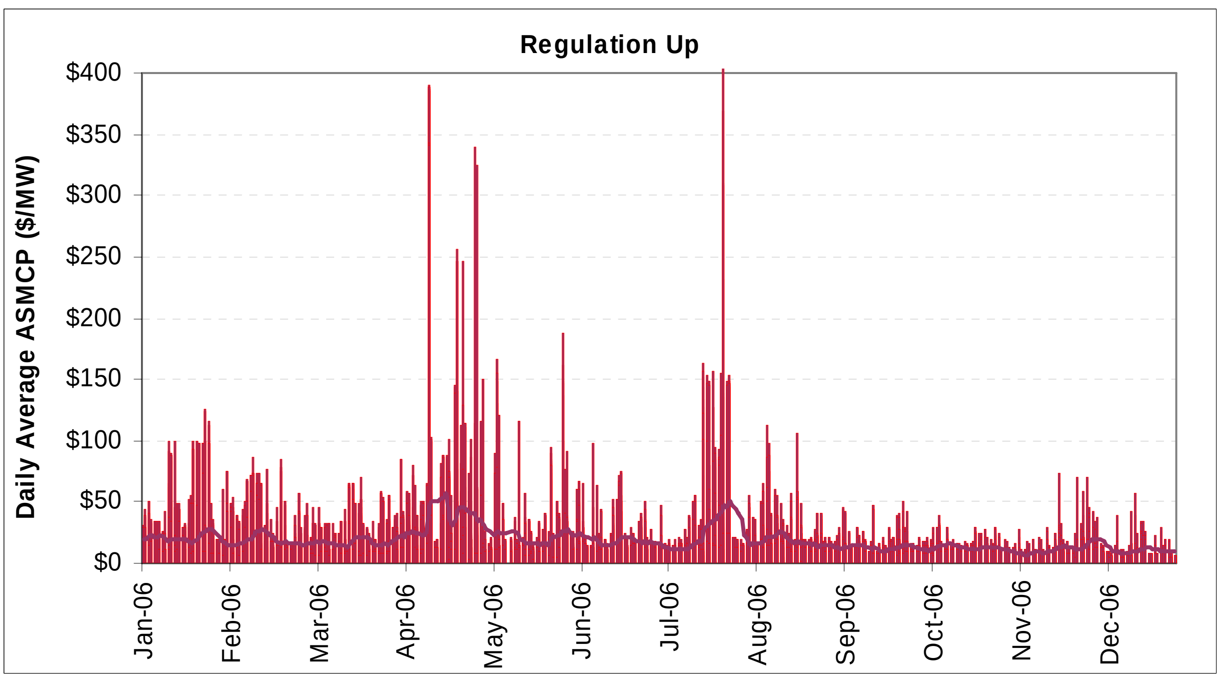
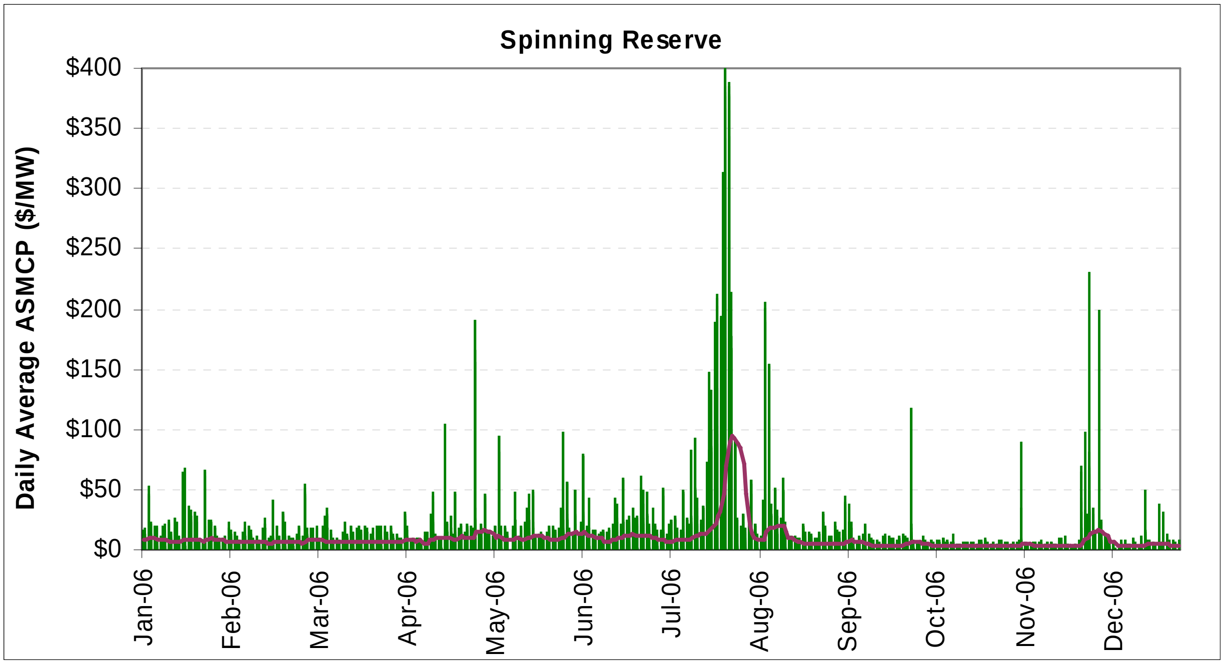
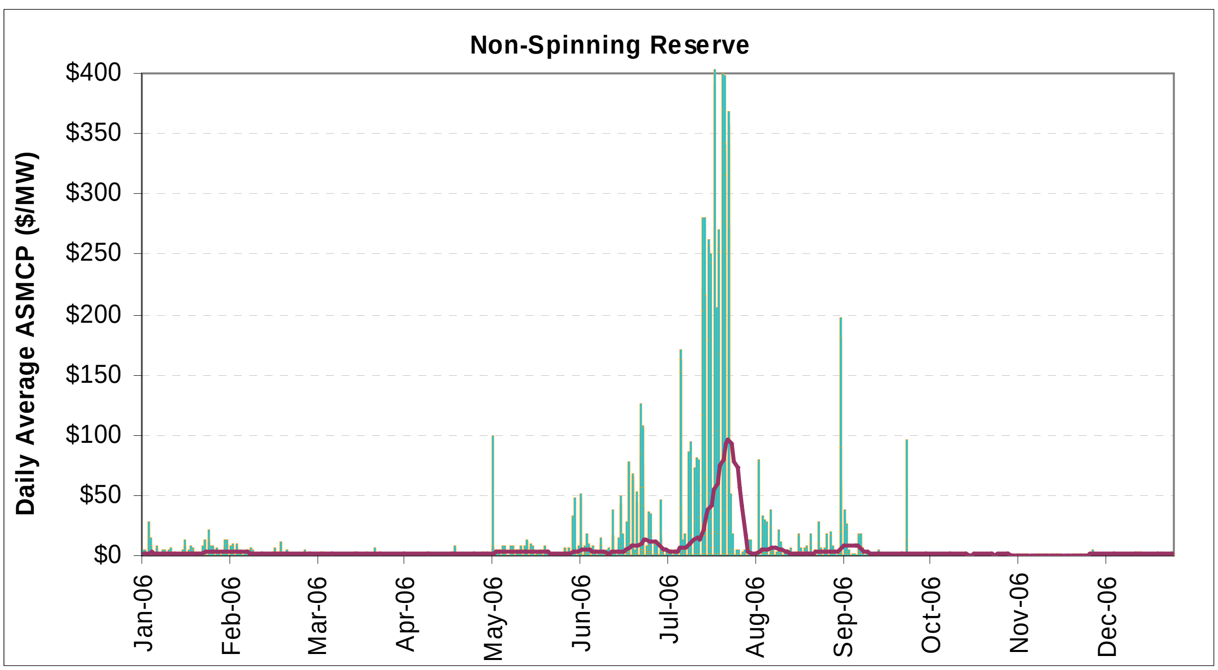


Figure 4.13 Day Ahead Operating Reserve Market Clearing Prices (A/S MCPs) with Seven Day Moving Averages





The A/S price duration curves for the Day Ahead Markets, Figure 4.14 and Figure 4.15, reflect generally expected price behavior with the most valuable products exhibiting the highest sustained prices. Overall, Operating Reserve prices were at price levels above $25 in fewer than 5 percent of the operating hours. At the same time Regulation Reserve prices over $25 were exhibited in fewer than 20 percent of operating hours.

Figure 4.14 Price Duration Curves for 2006 Regulation Reserve Markets

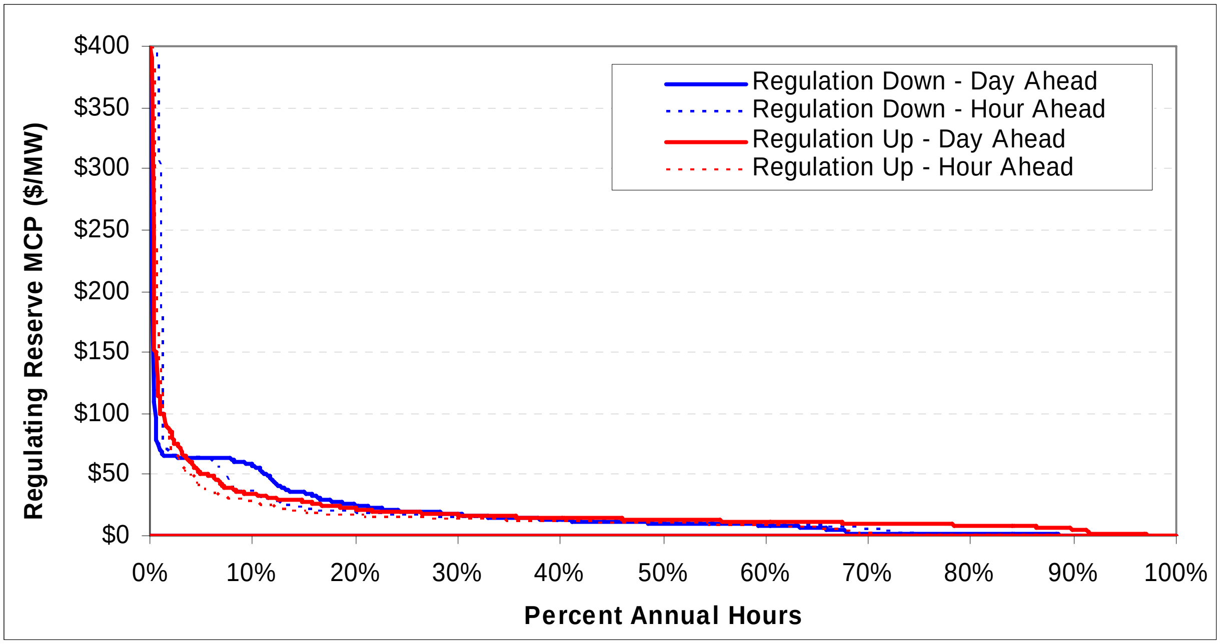
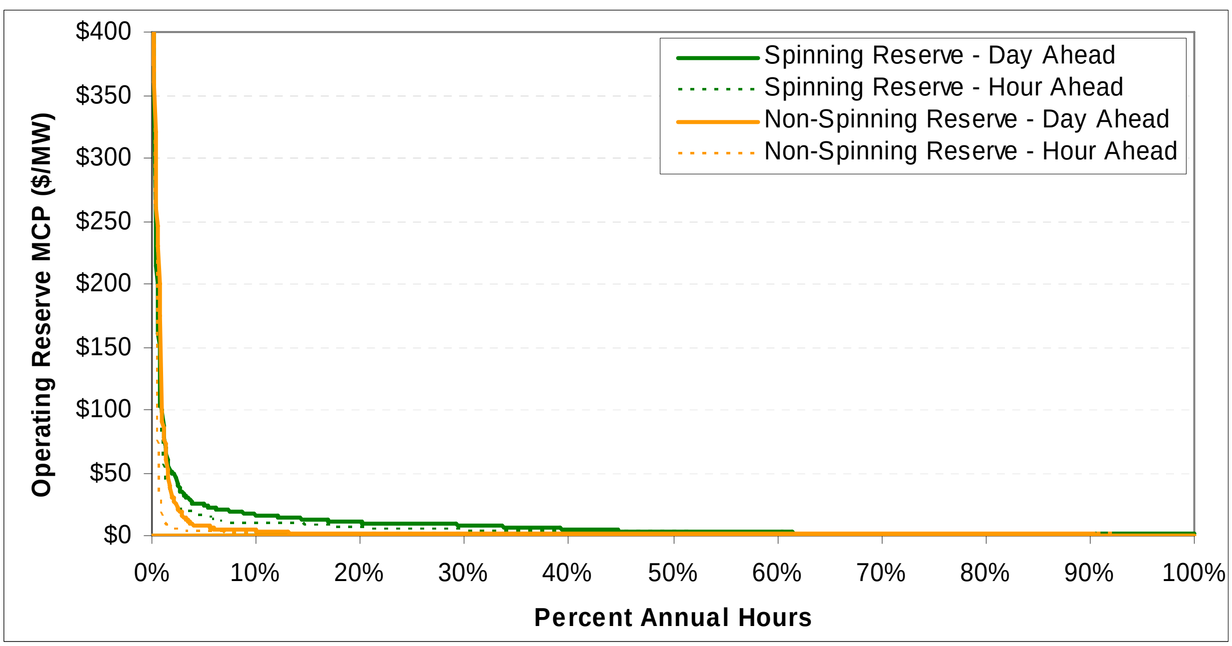


Figure 4.15 Price Duration Curves for 2006 Operating Reserve Markets

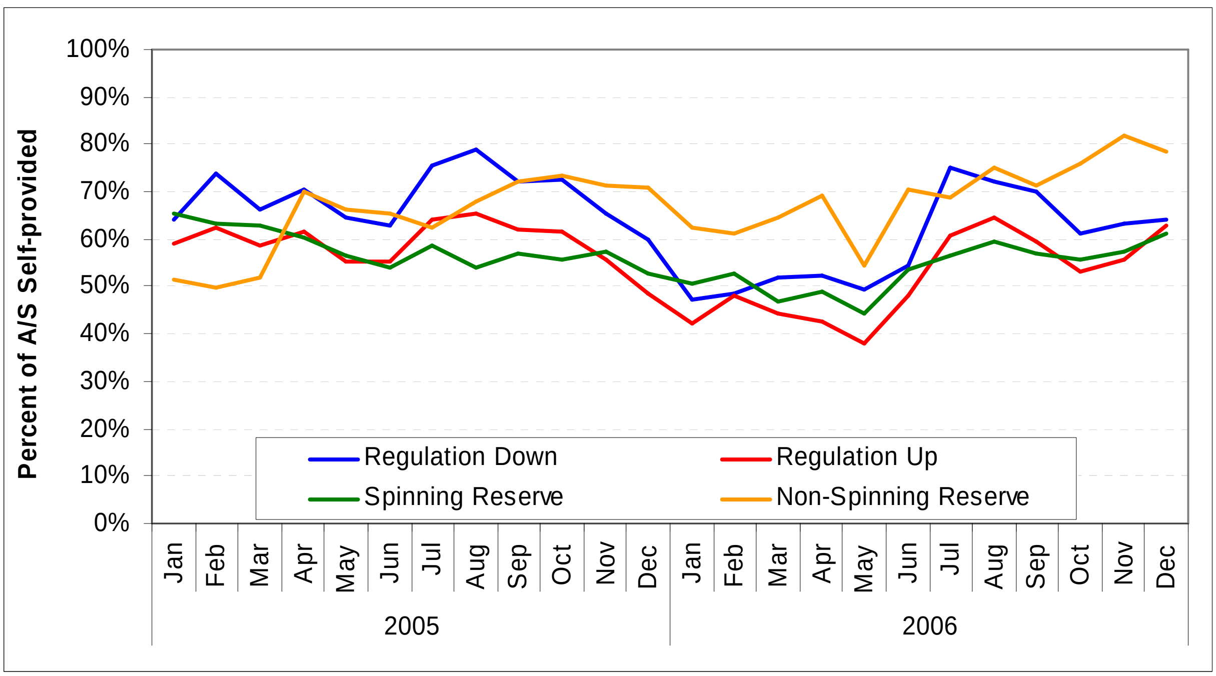


4.5 Ancillary Services Supply

4.5.1 Self-Provision of Ancillary Services

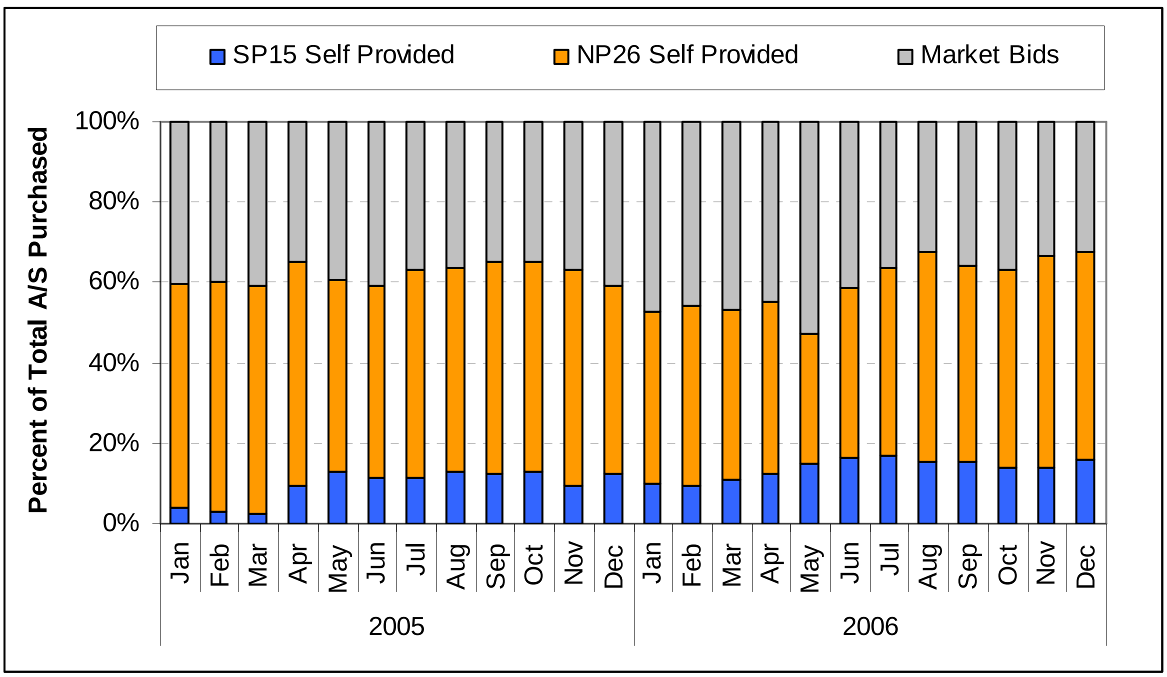
Self-provided ancillary services remained a significant share of the total supply in 2006, ranging between 40 and 70 percent for most services in most months. With the exception of Non-Spinning Reserve, however, self-provision on all other services was down in the first half of 2006 compared to 2005, particularly for upward regulation (Figure 4.16). This decline is likely attributable to the abundance of hydro-electric generation which, as discussed in previous sections, reduced the available capacity for ancillary services. A high level of generation maintenance outages that occurred in the spring of 2006 may have also contributed to this trend. Hourly average self-provided Regulation Reserves, as a percent of purchases, increased during the summer months after the price spikes during the spring months.

Figure 4.16 Hourly Average Self-Provision of A/S



It is also interesting to view self provision by zone; accordingly, Figure 4.17 shows the breakout of total A/S procured by source (market bid, self-provided in NP26, and self-provided in SP15). During 2005 and 2006, the CAISO purchased A/S on a system-wide basis and did not practice zonal procurement during this period. Consistent with this practice, the percentages shown in this figure are with respect to total system-wide A/S procurement. Note that hourly average self-provision by resources (generation units or imports) in NP26 ranged from 32 percent to 53 percent during 2006 while the corresponding figure in SP15 was much lower, between 10 percent and 20 percent throughout 2006. Typically, due to relative loads in the north and south, the calculated A/S requirement in SP15 is higher that than of NP26. Although not shown in this chapter, on average, roughly 70 percent of A/S is procured in NP26 with the remainder in SP15. Combined procurement from resources in SP15 (procurement from market bids and self-provided A/S) is significantly lower than the calculated zonal A/S requirement. This disparity between north and south is facilitated by transmission capability on Path 15 and Path 26, along which energy from A/S can be transferred from north to south to provide reliability support in the event of a contingency.

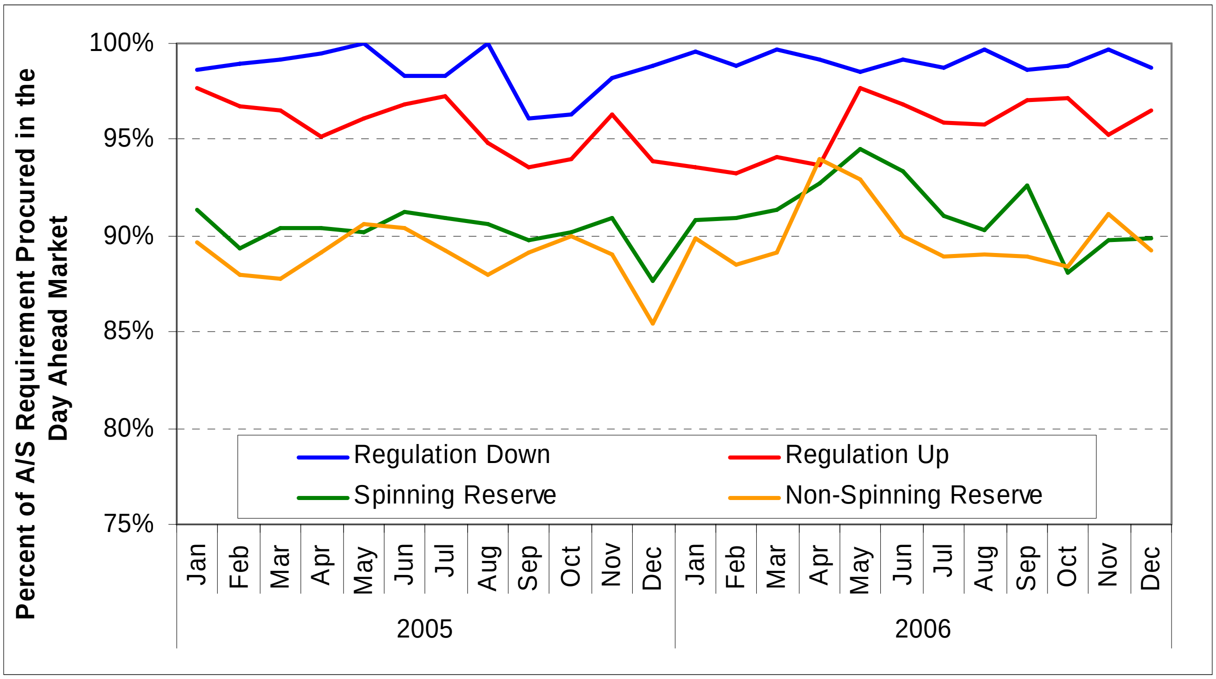
Figure 4.17 Hourly Average Self-Provision of A/S as a Percent of Total Procurement, by Zone for All Services Combined



4.5.2 Day-ahead vs. Hour-ahead Procurement

With the exception of Non-Spinning Reserve, the percent of A/S requirement procured in the Day Ahead Market remained relatively stable around or above 90 percent. The proportion of Non-Spinning Reserve procured in the Day Ahead was between 85 percent and 90 percent for most of the year (Figure 4.18).

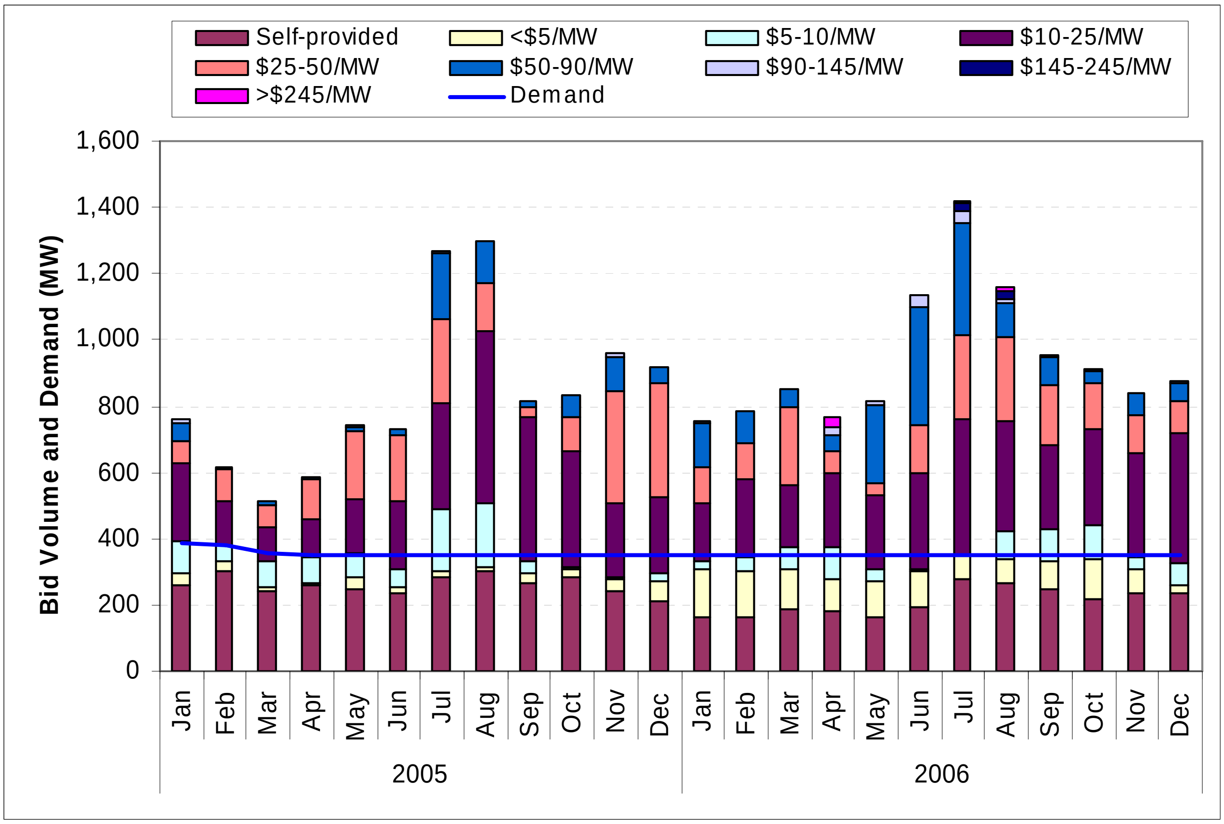
Figure 4.18 Hourly Average Day-Ahead Procurement, 2005 - 2006



4.5.3 Downward Regulation Reserve

Figure 4.19 displays the Downward Regulation bid composition by month for the past two years. The total hourly average supply of Downward Regulation bids was higher for most months in 2006 relative to 2005. There was also a higher share of bid volumes for Downward Regulation at the lowest price range of "less than $5/MW" throughout most of the year compared to 2005. Figure 4.19 also shows a significant increase in the quantity of bids at $50/MW or greater during the May to August timeframe in 2006.

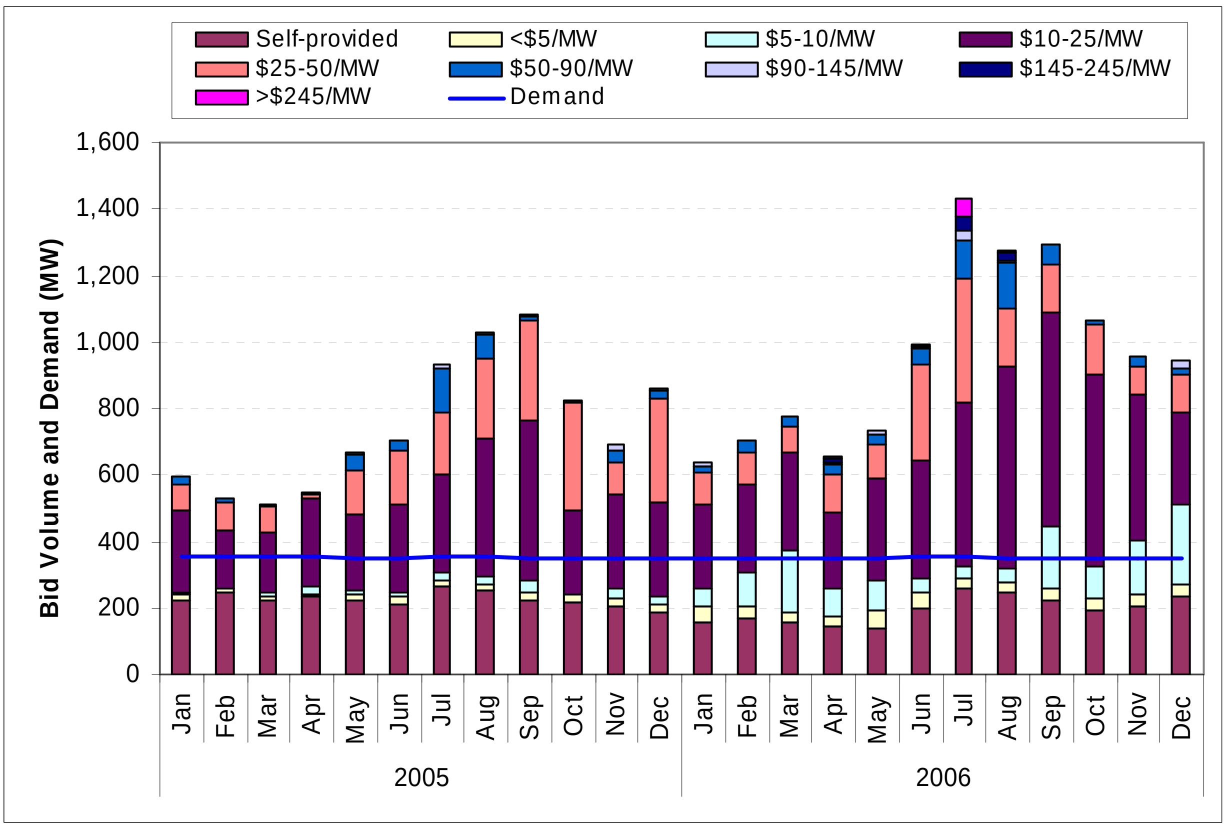
Figure 4.19 Day-Ahead Downward Regulation Reserve Bid Composition: 2005 – 2006 (Hourly Averages)



4.5.4 Upward Regulation Reserve

The Upward Regulation bid composition by month for the past two years appears in Figure 4.20. Similar to Regulation Down, the average hourly supply of Upward Regulation bids was higher in most months in 2006 relative to 2005, particularly during the summer months of July through August. Also evident in Figure 4.20 is an increase volume of bids in the "less than $5/MW" and "$5-$10/MW" bid categories, which helped to offset the decline in self-provision quantities and moderate Upward Regulation prices in most months. On the other hand, a relatively small percent of self-procurement occurred during the April 2006 and this, along with the high hydroelectric conditions, contributed to increased price spikes in April. Additionally, high price bids reflecting scarce capacity and higher expected opportunity cost in July 2006 contributed to the spikes during that month.

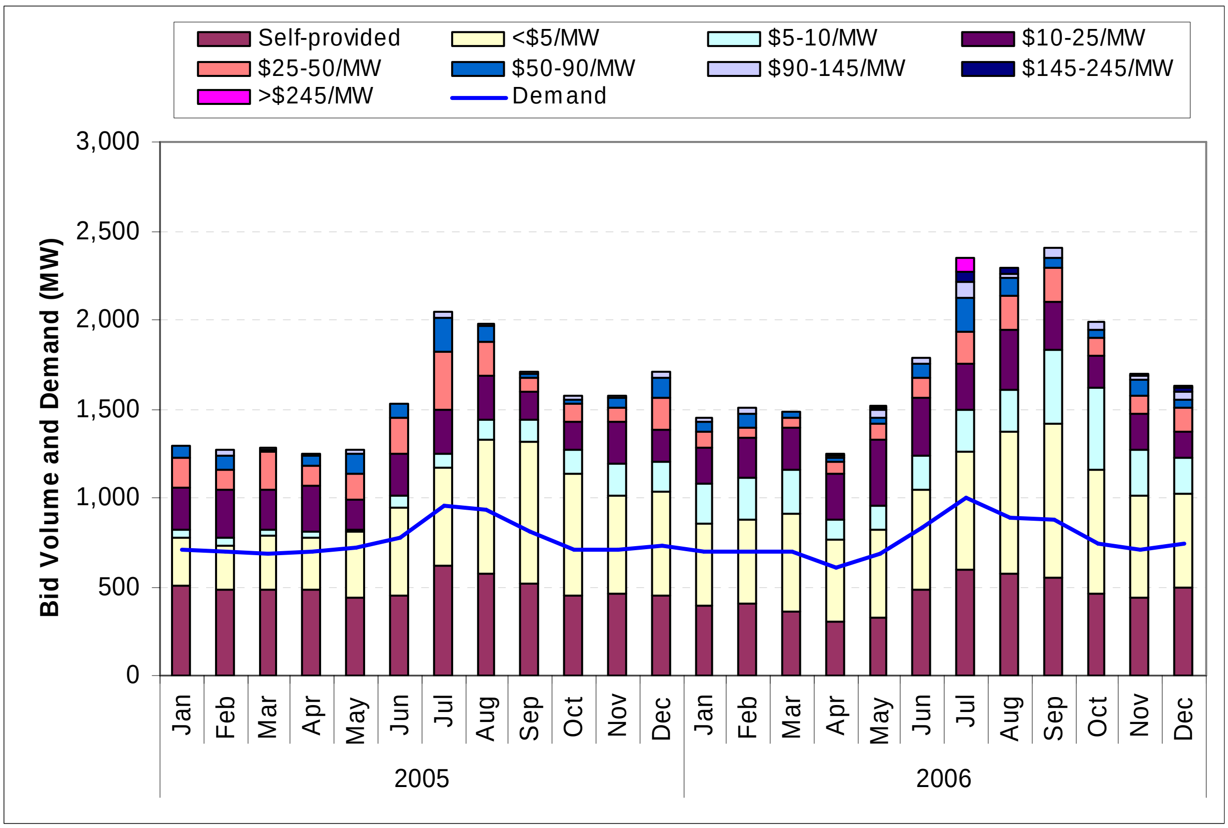
Figure 4.20 Day-Ahead Upward Regulation Reserve Bid Composition: 2005 – 2006 (Hourly Averages)



4.5.5 Spinning Reserve

As was the case for the Regulation Reserve Markets, average bid quantities for Spinning Reserve were also higher for most months in 2006 as compared to 2005 (Figure 4.21). A relatively large supply of Spinning Reserve bids priced below $5/MW kept the Spinning Reserve prices low during the off-peak season in 2006. Figure 4.21 also shows a significant quantity of Spinning Reserve bids greater than $245 in July 2006, which accounted for the price spikes observed in that market during the heat wave.

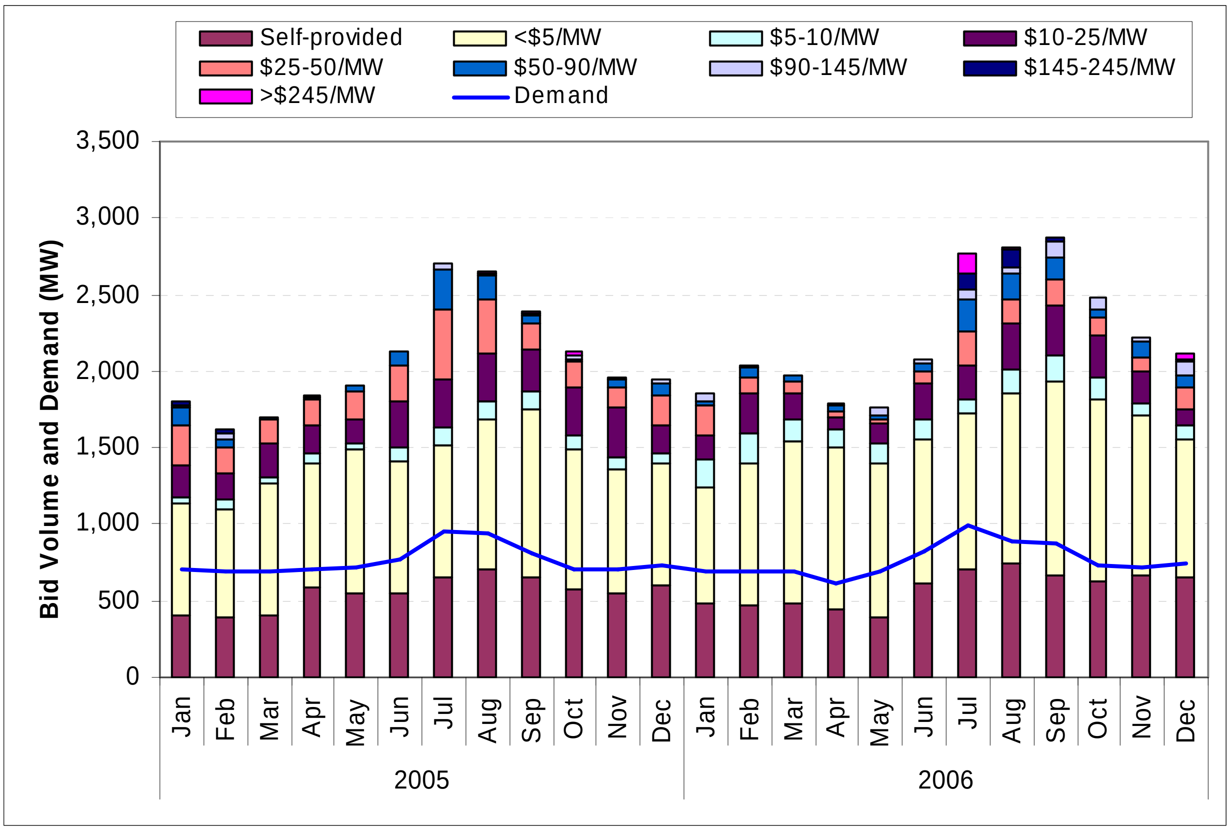
Figure 4.21 Day-Ahead Spinning Reserve Bid Composition: 2005 – 2006 (Hourly Averages)



4.5.6 Non-Spinning Reserve

Following the same trend as the other reserve markets, the hourly average supply of Non-Spinning Reserve bids was higher in most months of 2006 as compared to 2005. Substantial bid volumes at the sub-$5/MW level drove the overall decline in the average price for Non-Spinning Reserves. Extreme bid prices in the “greater than $245/MW” range in July 2006 accounted for the majority of the spikes that occurred during the heat wave. Figure 4.22 depicts the Non-Spinning Reserve bid composition by month for the past two years.

Figure 4.22 Day-Ahead Non-Spinning Reserve Bid Composition: 2005 – 2006 (Hourly Averages)



4.5.7 Bid Sufficiency

Bid insufficiency occurs when there is not enough available capacity bid into the markets to meet the procurement requirements. In addition to potentially creating reliability issues, bid insufficiency in the A/S markets can result in market power concerns as essentially any supplier to the A/S market in bid deficient hours is pivotal. Additionally, market power concerns can arise if bid sufficiency exists but only marginally so. In these cases, certain suppliers may also be pivotal in the sense that the A/S requirements could not be met absent their supply. The CAISO employs several measures of bid sufficiency. Volumes of capacity shortages convey information about the magnitude of the deficiency events and the count of operating hours where bid-in capacity falls short of requirements represent commonly used metrics that provide insight into the frequency and severity of shortage events. Table 4.2 provides these two metrics for the past two operating years.

Table 4.2 Bid Insufficiency (2005 – 2006)

Number of Hours With Shortage					
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2005	163	135	279	107	684
2006	159	110	145	113	527
Percent Δ	-2%	-19%	-48%	6%	-23%

Average Percent of Requirement Short					
	Regulation Up	Regulation Down	Spinning Reserve	Non-Spinning Reserve	All Services
2005	9%	14%	5%	6%	7%
2006	21%	16%	8%	15%	13%

A/S markets experienced a significant decline in hours of bid insufficiency in 2006 compared to 2005, with the exception in the Non-Spinning Reserve market for which the number of hours experiencing bid insufficiency increased by 6 percent. Nonetheless, the average percent of requirement shortage during bid deficiency hours actually increased significantly in 2006 for all four types of reserves. Figure 4.23 through Figure 4.26 show the frequency of hourly bid deficiencies and the average amount of deficiency (expressed as a percentage of the total requirement) by month and by service, for the past two years. The majority of the bid insufficiency of Regulation Reserves occurred during the spring months of 2006. During these periods of heavy hydro flows, hydroelectric generation tended to displace higher cost non-hydroelectric resources (e.g., thermal resources) resulting in less non-hydroelectric resources being on-line and available to offer regulation services. This factor coupled with the fact that many hydro resources choose not to provide regulation services due to water management constraints and other operational considerations, resulted in greater hours of bid insufficiency for Regulation Reserves. Most Spinning and Non-Spinning bid insufficiencies occurred during the peak summer months when demand for energy and reserves was at record levels. Mild fall and winter conditions contributed to the overall drop of the total insufficient hours.

Figure 4.23 Frequency of Bid Insufficiency in the Hour Ahead Market and Average Capacity Short – Regulation Down

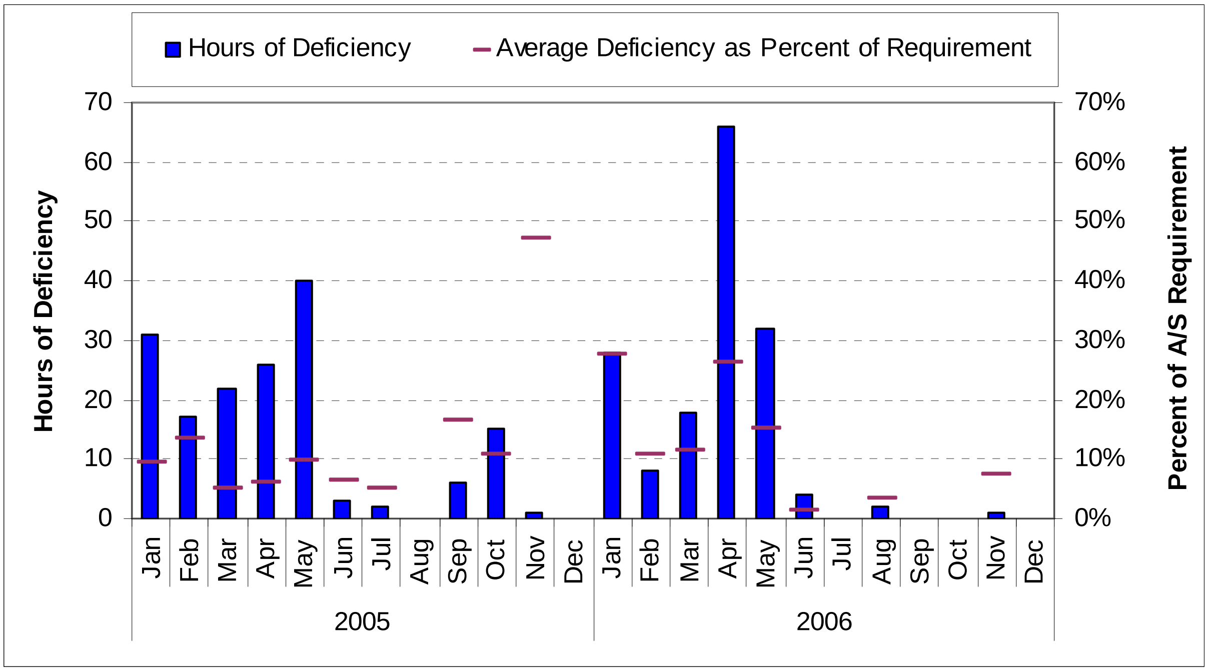


Figure 4.24 Frequency of Bid Insufficiency in the Hour Ahead Market and Average Capacity Short – Regulation Up

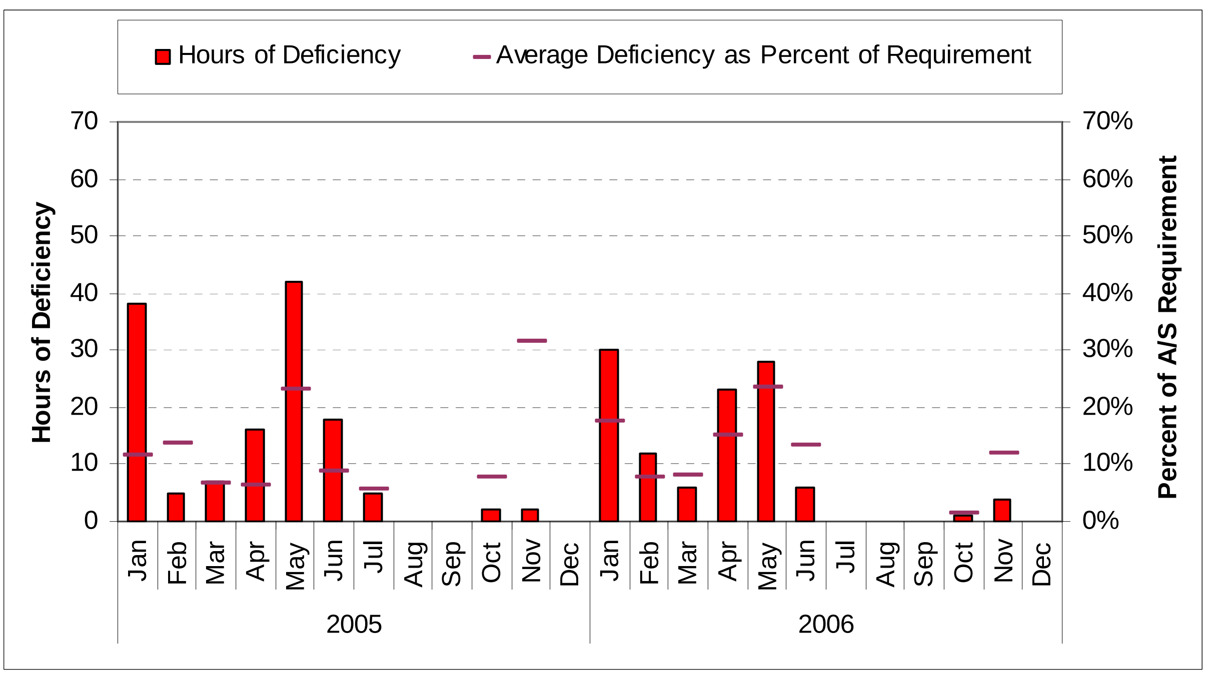


Figure 4.25 Frequency of Bid Insufficiency in the Hour Ahead Market and Average Capacity Short – Spinning Reserve

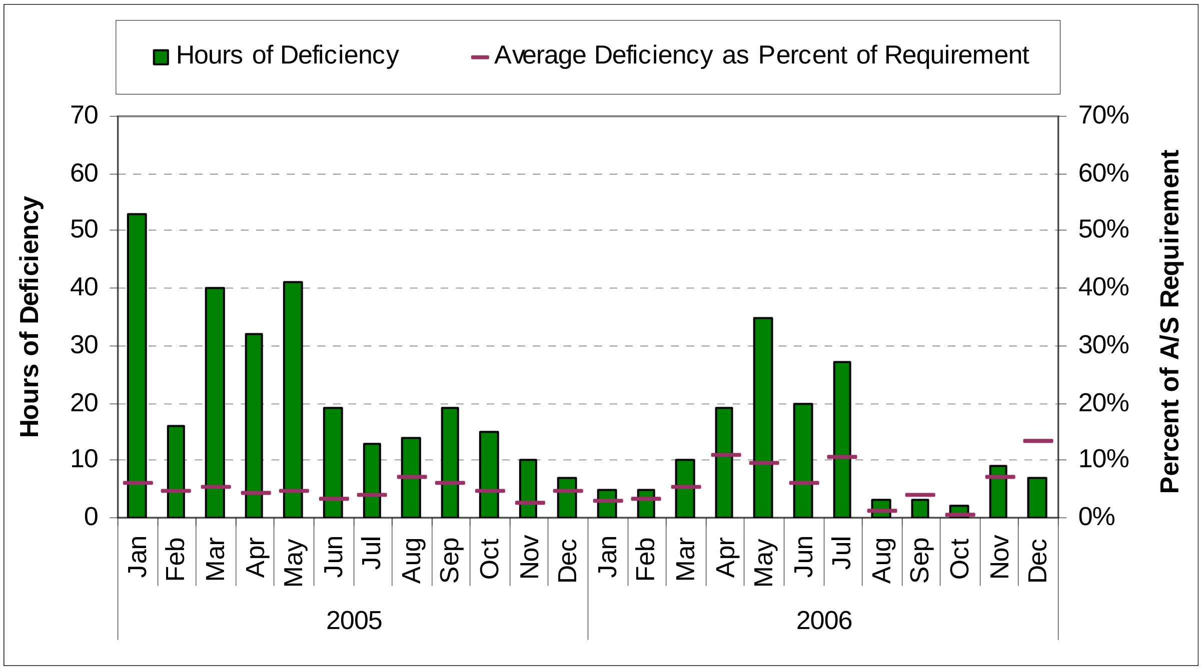
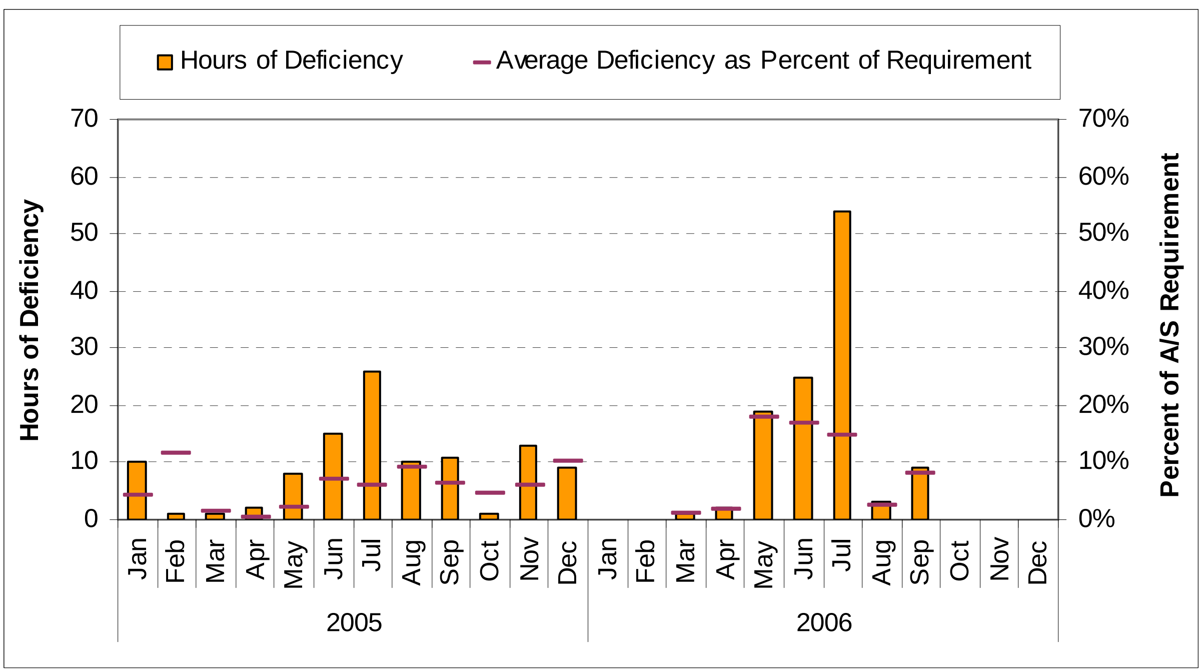


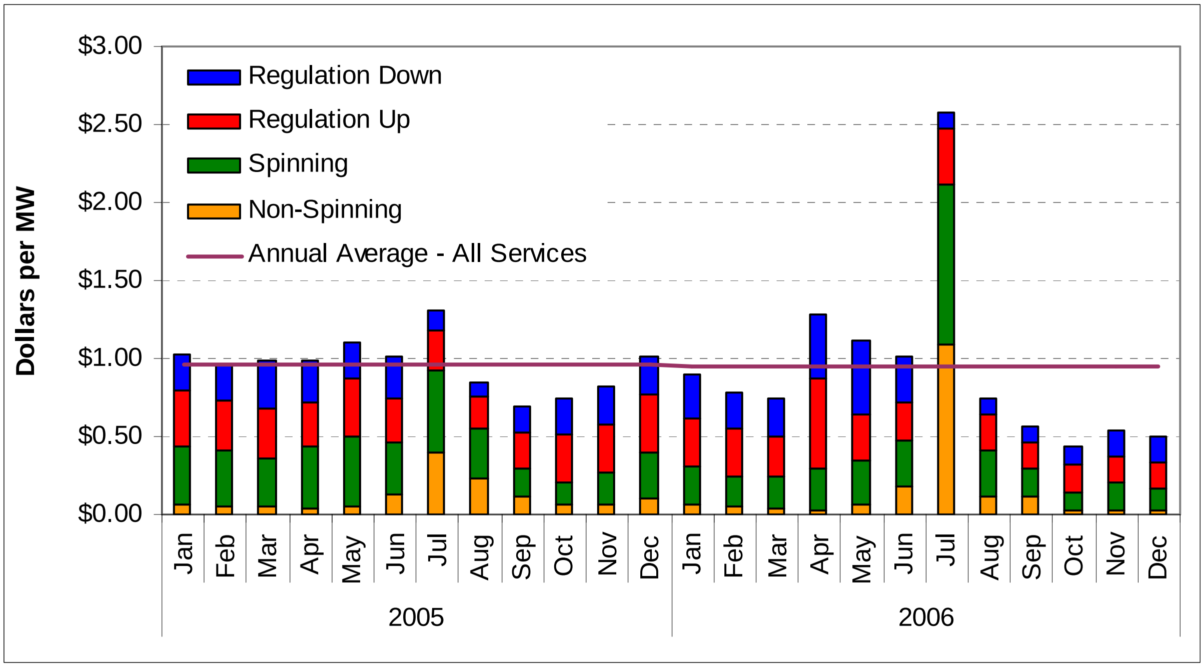
Figure 4.26 Frequency of Bid Insufficiency in the Hour Ahead Market and Average Capacity Short – Non-Spinning Reserve



4.6 Costs

The total cost of A/S capacity per unit of MWh load remained nearly unchanged from 2005, despite the price spikes seen above $250/MW seen in April and July. The average cost to load in 2006 averaged $0.95/MWh compared to a $0.96/MWh average the year prior. Figure 4.27 provides the monthly details on these costs.

Figure 4.27 Monthly Cost of A/S per MWh of Load



5 Inter-Zonal Congestion Management Market

5.1 Summary of 2006 Inter-Zonal Congestion Management Market

5.1.1 Overview

Under the current zonal model, the CAISO manages congestion in the forward market only on major inter-ties and two large internal paths (Path 15 and Path 26). It uses adjustment bids to mitigate the congestion while minimizing the cost of schedule adjustments and keeping each Scheduling Coordinator's (SC) schedule in balance. The marginal SC establishes the usage charge for the inter-zonal interface. All SCs pay this charge based on their accepted, scheduled flow on the interface. The CAISO pays the net amount of congestion charges it collects to the Transmission Owners (TOs) and the owners of Firm Transmission Rights (FTRs). Figure 5.1 shows the active congestion zones and major inter-zonal pathways (branch groups) in the CAISO grid. The new footprint of the CAISO grid reflects several operational changes that became effective on December 1, 2005, including:

- Transition of COTP and MID to the SMUD Control Area,[1]
- TID becoming an independent control area,[2]
- The new Plumas-Sierra Interconnection,
- The new and converted metered sub-systems, and
- A Pilot Pseudo Tie for Calpine's Sutter Plant.

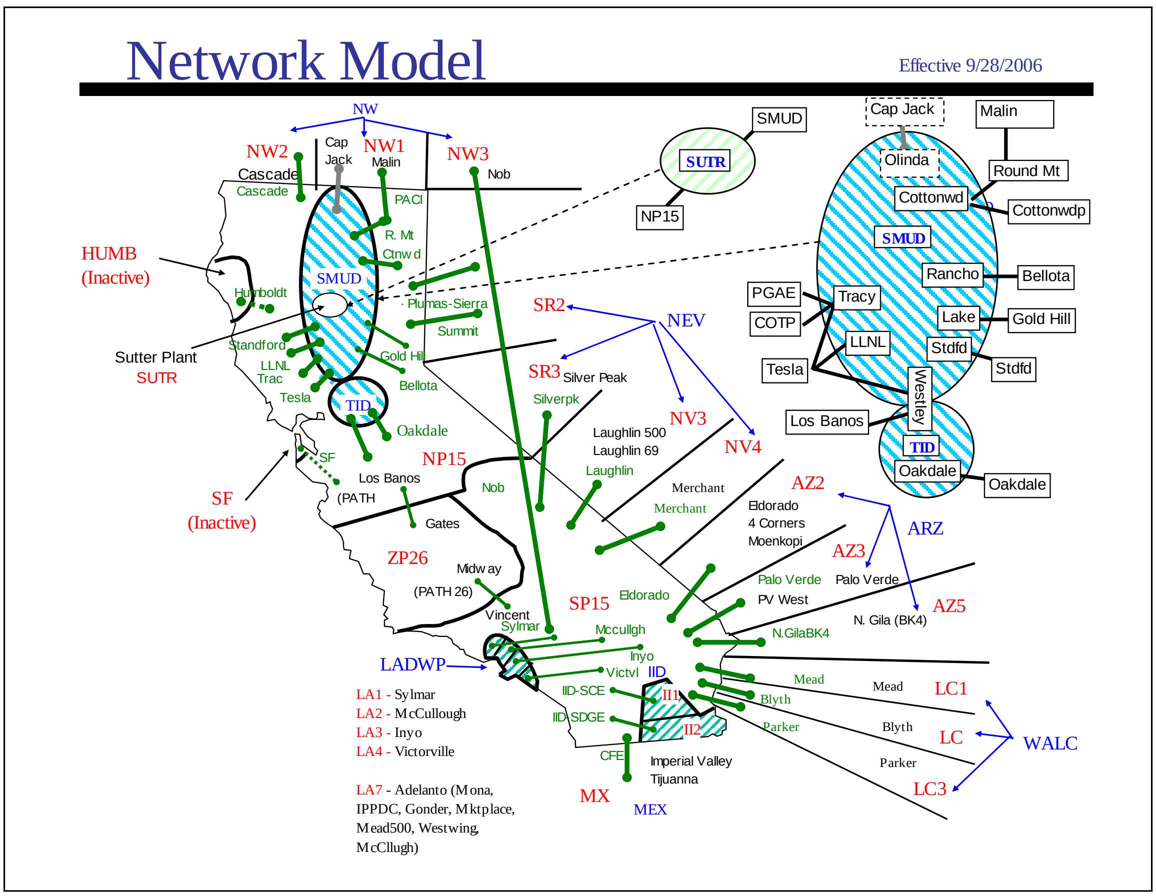
Total inter-zonal congestion cost for both the Day Ahead and Hour Ahead Markets in 2006 was $56 million, which is quite consistent with annual costs for the two previous years. Table 5.1 shows the historical annual total inter-zonal congestion cost since the year 2000. The majority of 2006 inter-zonal congestion cost (93 percent) can be attributed to 7 branch groups (Palo Verde, PACI, Eldorado, IPP (DC) – Adelanto,[3] NOB, Mead, Path 26), with Palo Verde constituting the largest share. The next section provides a more detailed breakdown of congestion frequency and cost by individual branch group.

[1] COTP = California-Oregon Transmission Project, MID = Modesto Irrigation District, SMUD = Sacramento Municipal Utility District.
[2] TID = Turlock Irrigation District
[3] IPP-Adelanto is a 500kv DC transmission line owned by the Los Angeles Department of Water and Power (DWP).

Table 5.1 Historical Inter-Zonal Congestion Cost

Year	Total Inter-Zonal Congestion Cost ($ M)
2000	$391
2001	$107
2002	$42
2003	$26
2004	$56
2005	$55
2006	$56

Figure 5.1 Active Congestion Zones and Branch Groups



5.1.2 Inter-Zonal Congestion Frequency and Magnitude

This section summarizes frequencies and average congestion prices for major inter-zonal interfaces (branch groups) in 2006. Table 5.2 lists all active inter-zonal branch groups managed by the CAISO in its forward congestion management market in 2006.

Table 5.2 Summary of Active Branch Groups in the CAISO Market (2006)

Branch Group	From Zone	To Zone	Interconnecting Control Area	Tie Point	Effective Date	Comments
PACI _BG	NW1	NP15	BPA	MALIN_5_RNDMTN	12/1/2005	Previously COI
PATH15 _BG	ZP26	NP15	N/A		2/1/2000	
CASCADE _BG	NW2	NP15	PACW	CASCAD_1_CRAGVW		
SUMMIT _BG	SR2	NP15	SPP	SUMITM_1_SPP		
SYLMAR-AC_BG	LA1	SP15	LDWP	SYLMAR_2_LDWP		
NOB _BG	NW3	SP15	BPA	SYLMAR_2_NOB		
CFE _BG	MX	SP15	CFE	IVALLY_2_23050		
PARKER _BG	LC3	SP15	WALC	PARKR_2_GENE		
LAUGHLIN _BG	NV3	SP15	NPC	MOHAVE_6_69KV		
SILVERPK _BG	SR3	SP15	SPP	SLVRPK_7_SPP		
BLYTHE _BG	LC2	SP15	WALC	BLYTHE_1_WALC		
PALOVRDE _BG	AZ3	SP15	SRP	PVERDE_5_DEVERS		
				PVERDE_5_NG-PLV		
IID-SDGE _BG	II2	SP15	IID	IVALLY_2_230S		
IID-SCE _BG	II1	SP15	IID	MIRAGE_2_COCHLA		
				DEVERS_2_COCHLA		
ELDORADO _BG	AZ2	SP15	APS	ELDORD_5_PSUEDO		
				FCORNR_5_PSUEDO		
				MOENKO_5_PSUEDO		
INYO _BG	LA3	SP15	LDWP	INYOS_2_LDWP		
N.GILABK4_BG	AZ5	SP15	APS	NGILA_5_NG4		
PATH26 _BG	SP15	ZP26	N/A		2/1/2000	
MERCHANT _BG	NV4	SP15	NPC	MRCHNT_2_ELDORD	10/15/1999	
RNCHLAKE _BG	SMDE	NP15	SMUD	RANCHO_2_BELOTA	6/18/2002	
		NP15	SMUD	LAKE_2_GOLDHL	6/18/2002	
MEAD _BG	LC1	SP15	WALC	MEAD_2_WALC	4/1/1998	
MCCULLGH _BG	LA2	SP15	LDWP	ELDORD_5_MCLLGH	4/1/1998	
VICTVL _BG	LA4	SP15	LDWP	LUGO_5_VICTVL	4/1/1998	
CTNWDWAPA_BG	SMD2	NP15	SMUD	CTNWDW_2_CTTNWD	1/1/2005	SMUD-WAPA
CTNWDRDMT_BG	SMD3	NP15	SMUD	CTNWDW_2_RNDMTN	1/1/2005	SMUD-WAPA
TRACYPSDO_BG	SMD5	NP15	SMUD	TRCYPP_2_TESLA	1/1/2005	SMUD-WAPA
LLNLTESLA_BG	SMD8	NP15	SMUD	LLNL_1_TESLA	1/1/2005	SMUD-WAPA
WSTWGMEAD_BG	AZ6	LC5	ARIZ	WSTWNG_5_MEAD	1/1/2005	South PTO
MKTPCADLN_BG	LC4	LA7	LDWP	MKTPLC_5_ADLNTO	1/1/2005	South PTO
IPPDCADLN_BG	LA5	LA7	LDWP	IPPDC_5_ADLNTO	1/1/2005	South PTO
MONAIPPDC_BG	PC1	LA5	PACE	MONA_5_IPPDC	1/1/2005	South PTO
GONDIPPDC_BG	SR4	LA5	SRRA	GONDER_5_IPPDC	1/1/2005	South PTO
MEADMKTPC_BG	LC5	LC4	WALC	MEAD_5_MKTPLC	1/1/2005	South PTO
MEADTMEAD_BG	LC6	LC5	WALC	MEADT_5_MEAD	1/1/2005	South PTO
MCCLMKTPC_BG	LA6	LC4	LDWP	MCCLUG_5_MKTPLC	1/1/2005	South PTO
ADLANTOSP_BG	LA7	SP15	LDWP	ADLNTO_5_LUGO	1/1/2005	South PTO
ADLANTOSP_BG	LA7	SP15	LDWP	ADELNT_2_SYLMAR	1/1/2005	South PTO
SUTTRNP15_BG	SUTR	NP15	N/A		12/1/2005	Sutter Pseudo Tie
WSLYTESLA_BG	SMDJ	NP15	SMUD	WESTLY_2_TESLA	12/1/2005	SMUD-MID
STNDFDSTN_BG	SMDK	NP15	SMUD	STNDFD_1_STNCSF	12/1/2005	SMUD-MID
TRACYPGAE_BG	SMDL	NP15	SMUD	TRACY5_5_PGAE	12/1/2005	SMUD-COTP
TRACYCOTP_BG	SMDH	NP15	SMUD	TRACY5_5_COTP	12/1/2005	SMUD-COTP
MARBLESUB_BG	SR5	NP15	SPP	MBLSPP_6_MARBLE	12/1/2005	SPP
OAKDALSUB_BG	TDZ1	NP15	TID	OAKTID_1_OAKCSF	12/1/2005	TID
WSTLYLSBN_BG	TDZ2	NP15	TID	WESTLY_2_LOSBNS	12/1/2005	TID

Table 5.3 shows annual congestion frequencies and average congestion prices by branch group, direction (import or export), and market type (Day Ahead or Hour Ahead). The frequency of congestion in 2006 was highest on several of the main branch groups between the CAISO and neighboring Control Areas outside California. In the Day Ahead Market, the Mead and Palo Verde branch groups, the Pacific DC Inter-tie (also known as the North-of-Oregon Border Inter-tie, or NOB, as listed in the table), and the Pacific AC Intertie (PACI), all were congested in at least 10 percent of hours. In the Hour Ahead Market, the Pacific AC and DC Inter-ties were also congested in at least 10 percent of the total annual hours. The most frequently congested branch group in 2006 was the Pacific AC Inter-tie, at 18 percent and 17 percent of hours in the Day Ahead and Hour Ahead Markets, respectively with all of the congestion being in the import direction. The high frequency of congestion on the Pacific AC Inter-tie was due to strong hydroelectric production from the Pacific Northwest being imported to and through the CAISO Control Area during the spring and early summer of 2006. Congestion prices on the Pacific AC averaged $5/MW in the Day Ahead Market and $18/MW in the Hour Ahead Market, which was comparable to average prices on the Pacific-DC (NOB) branch group. Average day-ahead congestion prices on two major Southwest branch groups (Palo Verde and Eldorado) were higher than the Northwest, averaging $9/MW and $11/MW, respectively.

Table 5.3 Inter-Zonal Congestion Frequencies (2006)[4]

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested		Average Congestion Price ($/MWh)	
Branch Group	Import	Export	Import	Export	Import	Export	Import	Export
ADLANTOSP_BG	4	0	$4	$0	2	0	$28	$0
BLYTHE _BG	4	0	$2	$3	0	0	$9	$30
CASCADE _BG	1	0	$0	$0	0	0	$3	$0
CFE _BG	0	0	$0	$0	0	0	$20	$0
ELDORADO _BG	9	0	$11	$0	4	0	$14	$0
IID-SCE _BG	0	0	$2	$0	0	0	$50	$0
IID-SDGE _BG	0	0	$0	$30	0	0	$0	$30
IPPDCADLN_BG	6	0	$12	$0	4	0	$34	$0
MEAD _BG	13	0	$4	$0	8	0	$20	$0
MELONPLNT_BG	0	0	$0	$0	0	0	$0	$30
MERCHANT _BG	0	0	$0	$0	0	0	$0	$0
MKTPCADLN_BG	4	0	$1	$0	2	0	$3	$0
MONAIPPDC_BG	0	0	$0	$1	0	0	$0	$29
NOB _BG	10	0	$4	$0	10	0	$23	$5
PACI _BG	18	0	$5	$0	17	0	$18	$3
PALOVRDE _BG	15	0	$9	$0	8	0	$29	$0
PARKER _BG	4	0	$3	$0	0	0	$20	$3
PATH15 _BG	1	0	$10	$0	0	0	$11	$0
PATH26 _BG	0	5	$0	$3	0	4	$22	$15
RNCHLAKE _BG	0	0	$0	$30	0	0	$0	$0
SILVERPK _BG	0	0	$0	$0	1	0	$1	$0
SUMMIT _BG	6	0	$0	$0	3	0	$1	$0
SUTTRNP15_BG	0	0	$0	$0	0	0	$19	$0
TRACYCOTP_BG	0	0	$0	$0	0	0	$5	$0
TRACYPSDO_BG	0	0	$0	$0	0	0	$0	$0
TSLASTDFD_BG	0	1	$0	$30	0	0	$0	$0
VICTVL _BG	0	0	$0	$0	0	0	$0	$5
WSLYTESLA_BG	0	0	$30	$0	0	0	$30	$0
WSTLYLSBN_BG	0	0	$30	$0	0	0	$30	$30
WSTWGMEAD_BG	2	0	$3	$0	1	0	$5	$0

5.1.3 Inter-Zonal Congestion Usage Charges and Revenues

Table 5.4 shows the annual congestion revenues for the major CAISO branch groups in 2006. The total congestion revenue of approximately $56.4 million represents a 3.2 percent increase above the 2005 total. Thirty (30) percent of congestion costs were incurred on the Palo Verde branch group in the import direction in 2006, compared to 36 percent in 2005. Another 21 percent was incurred on the Pacific AC Inter-tie (PACI), nearly all in the import direction, which is a substantially higher proportion than the 12 percent of total congestion cost on COI incurred in 2005. Other branch groups having significant increases in congestion costs from 2005 include: the Pacific DC Inter-tie, also referred to and shown in the table as the North-of-Oregon Border (NOB) branch group, which had a threefold increase in congestion costs in 2006

[4] In all tables, North-to-South congestion on Path 26 is represented as "Exports". South-to-North congestion on Path 15 is represented as "Imports".

(increasing from 3 to 10 percent of total costs); the IPP(DC)-to-Adelanto (IPPDCADLN) branch group (increasing from 3 to 8 percent of total costs); and the Mead branch group (increasing from 2 to 6 percent of total costs). One branch group that experienced a sharp decline in congestion costs from 2005 was Blythe, which incurred approximately $8.75 million of congestion costs in 2005 but declined to $.12 million in 2006.

Table 5.4 Inter-Zonal Congestion Revenue (2006)[5]

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		
ADLANTOSP	$1,433,657	$0	$127,817	$0	$1,561,474	$0	$1,433,657	$127,817	$1,561,474	3%
BLYTHE	$112,032	$42	$10,574	$901	$122,607	$943	$112,074	$11,475	$123,550	0%
CASCADE	$0	$0	$604	$0	$604	$0	$0	$604	$604	0%
CFE	$0	$0	$2,812	$0	$2,812	$0	$0	$2,812	$2,812	0%
ELDORADO	$6,650,407	$0	$25,289	$0	$6,675,696	$0	$6,650,407	$25,289	$6,675,696	12%
IID-SCE	$1,338	$0	$3,260	$0	$4,598	$0	$1,338	$3,260	$4,598	0%
IID-SDGE	$0	$1,711	$0	$150	$0	$1,861	$1,711	$150	$1,861	0%
IPPDCADLN	$4,152,752	$0	$128,818	$0	$4,281,569	$0	$4,152,752	$128,818	$4,281,569	8%
LAUGHLIN	$0	$0	$0	$8	$0	$8	$0	$8	$8	0%
MEAD	$2,977,319	$0	$253,438	$0	$3,230,757	$0	$2,977,319	$253,438	$3,230,757	6%
MELONPLNT	$0	$0	$0	$451	$0	$451	$0	$451	$451	0%
MERCHANT	$26	$0	$0	$0	$26	$0	$26	$0	$26	0%
MKTPCADLN	$123,057	$0	$27,371	$0	$150,428	$0	$123,057	$27,371	$150,428	0%
MONAIPPDC	$0	$2,580	$0	$48,230	$0	$50,810	$2,580	$48,230	$50,810	0%
NOB	$5,151,724	$0	$377,001	$23,468	$5,528,726	$23,468	$5,151,724	$400,469	$5,552,194	10%
OAKDALSU	$0	$0	$0	-$14	$0	-$14	$0	-$14	-$14	0%
PACI	$12,169,213	$0	-$113,867	$1,991	$12,055,346	$1,991	$12,169,213	-$111,876	$12,057,337	21%
PALOVRDE	$16,974,558	$0	$95,990	$0	$17,070,548	$0	$16,974,558	$95,990	$17,070,548	30%
PARKER	$158,489	$0	$1,887	$449	$160,376	$449	$158,489	$2,336	$160,825	0%
PATH15	$1,853,557	$0	$69,257	$0	$1,922,814	$0	$1,853,557	$69,257	$1,922,814	3%
PATH26	$0	$3,209,426	$23,679	$123,558	$23,679	$3,332,984	$3,209,426	$147,237	$3,356,663	6%
RNCHLAKE	$0	$26,582	$0	-$1,772	$0	$24,810	$26,582	-$1,772	$24,810	0%
SILVERPK	$102	$0	$72	$0	$174	$0	$102	$72	$174	0%
STNDFDSTN	$0	$0	$0	$2	$0	$2	$0	$2	$2	0%
SUMMIT	$13,514	$0	$2,420	$0	$15,935	$0	$13,514	$2,420	$15,935	0%
SUTTRNP15	$0	$0	$3,787	$0	$3,787	$0	$0	$3,787	$3,787	0%
TRACYCOTP	$0	$0	$610	$0	$610	$0	$0	$610	$610	0%
TRACYPSDO	$0	$0	$121	$0	$121	$0	$0	$121	$121	0%
TSLASTDFD	$0	$5,062	$0	-$5,062	$0	$0	$5,062	-$5,062	$0	0%
VICTVL	$0	$0	$0	$10,112	$0	$10,112	$0	$10,112	$10,112	0%
WSLYTESLA	$12,844	$0	$963	$0	$13,806	$0	$12,844	$963	$13,806	0%
WSTLYLSBN	$6,271	$0	$272	$13,203	$6,543	$13,203	$6,271	$13,475	$19,745	0%
WSTWGMEAD	$56,157	$0	$9,235	$0	$65,392	$0	$56,157	$9,235	$65,392	0%
Total	**$51,847,018**	**$3,245,403**	**$1,051,408**	**$215,676**	**$52,898,426**	**$3,461,079**	**$55,092,421**	**$1,267,084**	**$56,359,504**	**100%**

Exports from the CAISO Control Area resulted in only $128,095 in congestion costs – nearly half on the Mona - IPP (DC) branch group, which connects to the Intermountain Power Project and is physically located in Utah.

Hour-ahead congestion accounted for 2.2 percent of congestion costs, or approximately $1.3 million. This small proportion is due to the fact that hour-ahead congestion typically occurs after SCs have adjusted their day-ahead schedules or as the result of changes in line ratings after the closure of the Day Ahead Market. Only those SCs that change their schedules in the Hour Ahead Markets are required to pay hour-ahead congestion charges. Thus, the volume of transactions in the Hour Ahead Market is much lower than that in the Day Ahead Market.

5 In all tables, North-to-South congestion on Path 26 is represented as "Exports". South-to-North congestion on Path 15 is represented as "Imports".

Figure 5.2 compares congestion costs in 2005 and 2006 on selected major paths. Congestion costs decreased on Palo Verde and Path 26, due in part to increased ratings on these paths, which are discussed in Chapter 1. Congestion costs increased on the Pacific AC Inter-tie (PACI) and the Pacific DC Intertie (NOB), due to strong hydroelectric production in the Pacific Northwest during the spring and summer and numerous transmission de-rates, which are discussed below. Congestion costs also increased on Eldorado and Mead, which transmit power between the Las Vegas and Los Angeles areas. Congestion costs on the IPP (DC) – Adelanto (IPPDCADLN) and Adelanto-SP26 (ADLANTOSP) also increased due to a single incident (discussed below).

Figure 5.2 Congestion Revenues on Selected Paths (2005 vs. 2006)

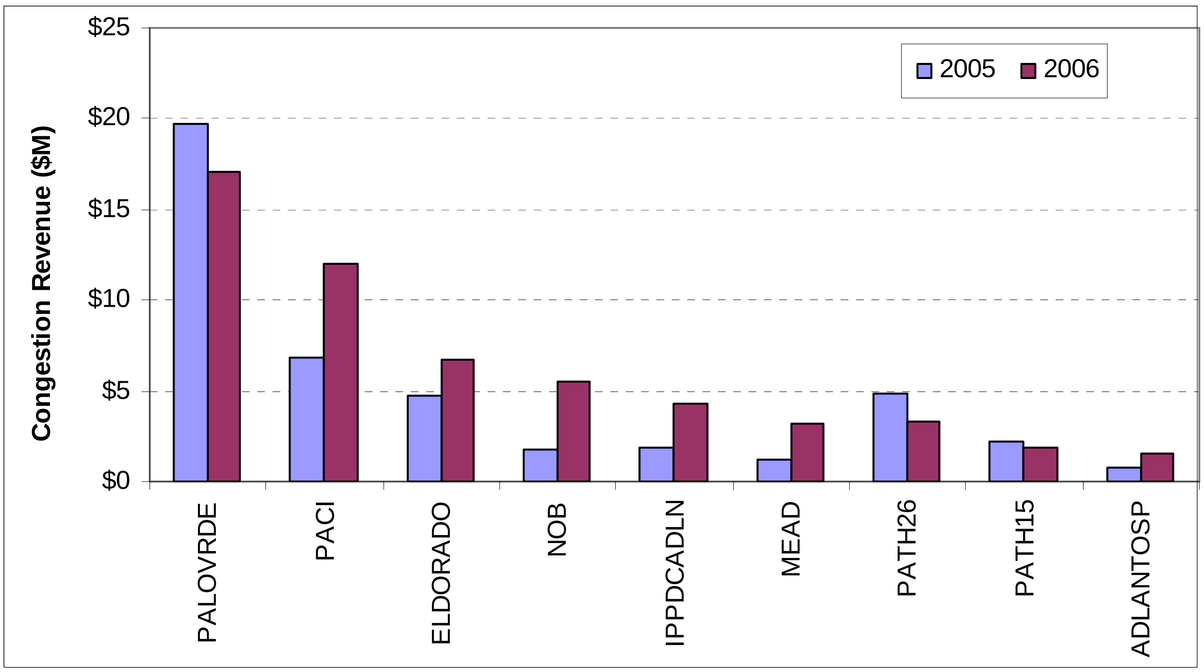


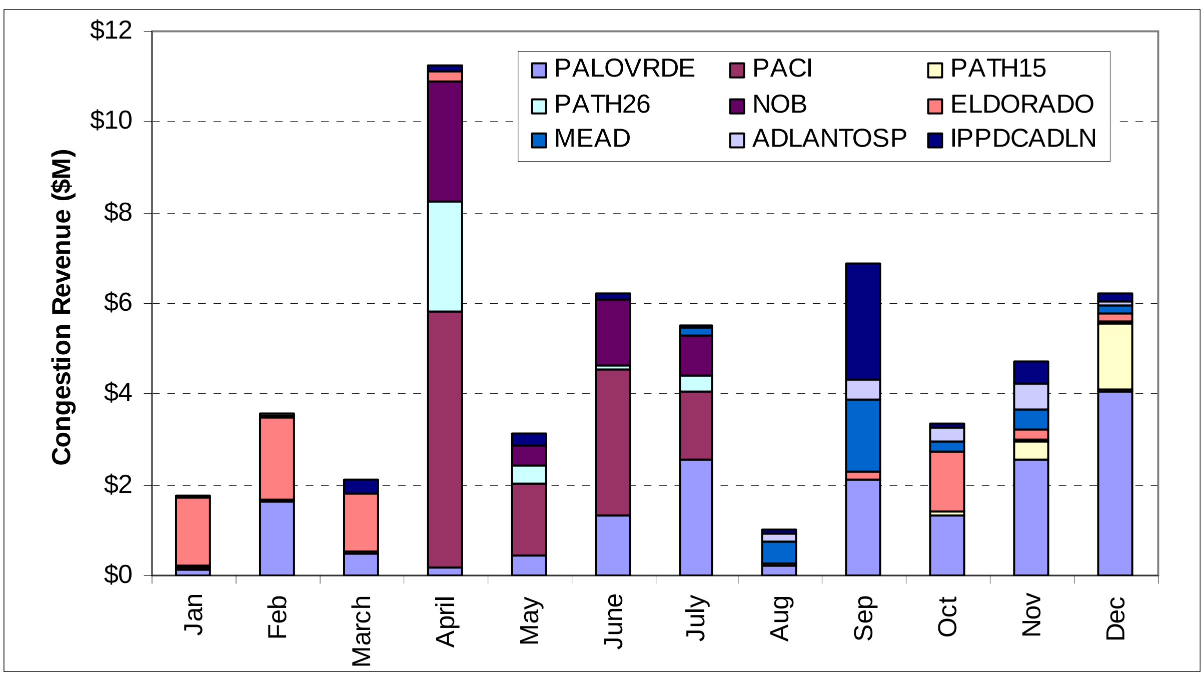
Figure 5.3 shows the seasonal pattern of congestion costs on major paths. The bulk of congestion costs were incurred from the Pacific Northwest into California in the spring and early summer months, notably April, the highest-cost month of the year. High north-to-south power flows coupled with various transmission de-rates during this period contributed to the high congestion costs.

In April, congestion on PACI was largely due to high north-to-south flows and capacity de-rates caused by significant Northern California stream flows resulting in a considerable amount of hydroelectric generation, and transmission line outages from Midpoint to Summer Lake, which impacted the west of Borah flows. For instance, from April 10 to April 24 the path capacity on the PACI was de-rated due to the forced outage of Fort Rock Cap Group #2, in conjunction with the Midpoint-Summer Lake 500 kV and Ashe-Marion #2-500 kV line outages. From April 17 to April 20, the PACI was further de-rated due to the forced outage of the Olinda-Tracy 500 kV line to bypass series capacitors, in conjunction with the outage of the Malin-Round Mountain #2 line to bypass the series capacitor bank. The NOB was also heavily congested in April due to a combination of planned and unplanned transmission line work. For example, Ashe-Slatt 1 500 kV line and Celilo converters #3 and #4 were removed from service from April 4-7. The Celilo converters were again removed from service on April 17, 18, and 19. Additionally, between April 20-30, NOB had capacity de-rates due to several planned and unplanned outages. Major transmission lines out-of-service during this period included: Slatt-Buckely 1-500 kV line, Midpoint-Summer Lake 500 kV line, Schultz-Raver 4-500 kV line, and Malin-Round Mountain #1-500 kV line series capacitors at Malin.

High congestion costs on Path 26 in April were also attributable to high north-to-south flows and transmission de-rates due to scheduled maintenance on the 500 kV lines, Midway-Vincent No. 1 and 2. The Midway-Vincent No. 1 line was removed from service from April 1-7 to install new relays, new controls, and transfer trip and breaker failure schemes, and then again on April 23 and 24 to remove the wave traps. This resulted in the capacity being de-rated from 3,700 MW to 2,600 MW. The outage of Midway-Vincent No. 2 from April 26-30 to replace old wave traps and structures also resulted in a de-rate to 2,600 MW that contributed to an increase in congestion costs for that path.

In Southern California, flows from east of the Colorado River were also limited by clearances associated with upgrades to series capacitors on the Palo Verde-Devers and Moenkopi-Eldorado transmission lines, which occurred throughout the winter and spring of 2006. Congestion charges on Palo Verde increased between May and July as California loads increased but receded in August due to relatively moderate California loads and higher demand for power in the Southwest, which limited the availability of power for export to California.

Figure 5.3 Monthly Congestion Charges on Selected Major Paths (2006)



On Saturday, July 1, 2006, a utility tower supporting the Palo Verde-Devers 500 kV line was toppled by a storm in that region, causing a system frequency disturbance and a curtailment of power imports from the Southwest into Southern California of approximately 1,500 MW. Because this occurred over a long holiday weekend, Southern California Edison was not able to get the line restored until Wednesday, July 5, at which time SCE installed a temporary tower known as a Lindsey emergency replacement tower to replace the toppled tower. This outage resulted in approximately $1.5 million in congestion costs on the Palo Verde branch group until the line was restored. The temporary tower was replaced with a permanent structure on December 19-22, requiring another service outage. During this outage, an additional $2 million in congestion costs were incurred.

Congestion in September totaled approximately $6.9 million and was heavily concentrated in the first week of the month, due largely to concurrent de-rates of transmission into Southern California. Beginning September 1, the Pacific AC and DC inter-ties, which bring power to California from Oregon, had been de-rated for scheduled maintenance in Oregon. This contributed to import congestion on Palo Verde beginning September 1. Between September 3 and 5, the Pacific DC Intertie, which connects generation in Oregon directly to SP15, was de-energized after a truck apparently struck a guy wire, in an unrelated incident elsewhere in Oregon. As this event occurred during the Labor Day holiday weekend, day-ahead schedules had been established on the previous Friday, September 1, through the entire period including operating day Tuesday, September 5. This resulted in approximately $2.2 million in import congestion on Mead, Eldorado, and Palo Verde.

There were also some significant congestion costs in September on the IPPDCADLN (IPP-Adelanto 500 kv DC line), which was attributed to a single day event. On September 6, the IPP-Adelanto 500 kv DC line, which connects the Intermountain Power Project in Utah to Los Angeles, was overscheduled, and had schedules curtailed by 0.03 MW in off-peak hours. No scheduling coordinator using this line apparently had submitted adjustment bids, so the price on the line stood at approximately $398/MWh for all of the off-peak hours on that day. This resulted in $2.1 million in congestion costs. However, most of the impacted schedules were hedge by FTRs.

Congestion in the fall of 2006 (October-December) was primarily on Palo Verde and was also exacerbated by transmission work. Beginning October 19, an Imperial Valley-North Gila 500 kv series capacitor was bypassed due to high flows and remained out of service for the rest of the year, affecting SCIT limitations and causing impedance on the Southwest Power Link. This resulted in an increase in power flows over Palo Verde, causing congestion. A few days later, the Eldorado-Yavapai, Eldorado-Moenkopi, and Moenkopi-Navajo 500 kv transmission lines were a derated or out for work through the end of the month. These issues resulted in de-rates of the Eldorado and Palo Verde branch groups and contributed to most of the congestion costs on Palo Verde between October and December. Finally, between December 11 and 21, switch upgrades at the Gates substation resulted in a de-rate of Path 15. On December 12, congestion on this line incurred costs of $1.4 million.

5.1.4 Existing Transmission Contracts and Phantom Congestion

An Existing Transmission Contract (ETC) is an encumbrance, established prior to the start-up of the CAISO, in the form of contractual obligation of a CAISO Participating Transmission Owner (PTO) to provide transmission service to another party, in accordance with terms and conditions specified in the contract, utilizing transmission facilities owned by the PTO that have been turned over to the CAISO operation control. There are two main aspects of the CAISO's current treatment of ETCs – a scheduling aspect and a settlement aspect – whereby ETC's schedules are accorded different treatment than the treatment accorded other schedules. With respect to scheduling, since start-up the CAISO has accommodated ETCs by (1) "setting-aside" transmission capacity on inter-ties and inter-zonal interfaces (i.e., Path 15 and Path 26) on a day-ahead basis for the sole use of ETC rights holders, and (2) holding that capacity off the market, irrespective of whether or not it was fully scheduled by the ETC right holders, up until 20 minutes before the start of the operating hour in real-time. With respect to the settlement aspect, ETC schedules are exempt from all Transmission Access Charges, the Congestion Management component of the Grid Management Charge (GMC), and any Usage Charges for congestion.

The CAISO's current treatment of ETCs in scheduling has created market inefficiencies and has been reported on in previous annual reports. It remained a problem in the congestion market in 2006. Under the current market rules, ETC holders have the full amount of their ETC capacity reserved for them in the Day Ahead and Hour Ahead Markets whether they actually use it or not. The unused capacity is only released 20 minutes before the operating hour. Often this capacity cannot be fully utilized with such short notice due to factors such as ramping limits of generating facilities or that market participants have already made other arrangements to meet their load obligations. The term "phantom congestion" refers to new firm use schedules that are curtailed because of reserved, but not used, ETC capacity[6] on congested branch groups.

Figures 5.6 through 5.8 show the amount of new firm use schedules that were curtailed due to phantom congestion on the Mead, Palo Verde, and PACI branch groups. Phantom congestion was quite prevalent on the Mead branch group through the second half of 2006 (Figure 5.6). However, it was less prevalent on the Palo Verde and PACI branch groups (Figures 5.7 and 5.8, respectively). As evident in Figure 5.7, almost all of the ETC capacity reserved on the Palo Verde branch group was utilized. ETC reservations and phantom congestion on the PACI branch group declined significantly from prior years due to the control area changes that occurred on this branch group in December 2005 – specifically, the transition of the California-Oregon Transmission Project (COTP) from the CAISO to the SMUD control area. Phantom congestion on the former California Oregon branch group (COI), which was comprised of both the COTP and PACI, was very prevalent in prior years due to the under-utilization of Transmission Ownership Rights on the COTP. With COTP no longer part of the CAISO, its under-utilization cannot be assessed.

6 This analysis considers Transmission Ownership Rights (TORs) to be the same as Existing Transmission Contracts in that they are treated similarly by the CAISO and can both result in phantom congestion.

Figure 5.4 Phantom Congestion on the Mead Branch Group (2006)

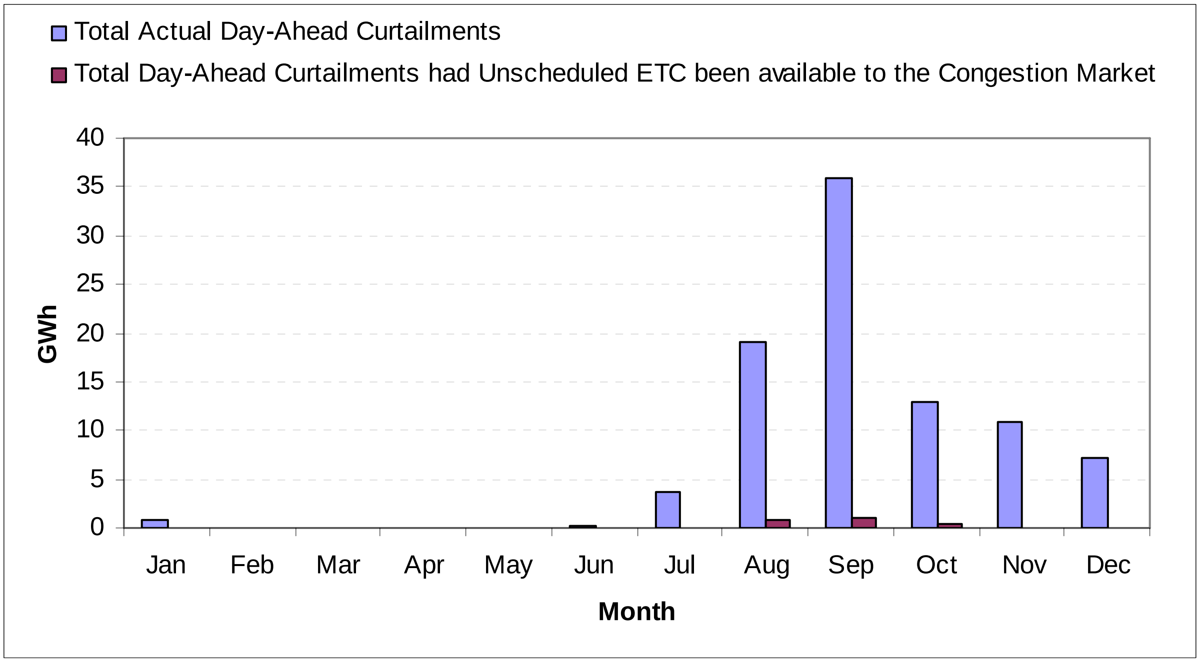


Figure 5.5 Phantom Congestion on the Palo Verde Branch Group (2006)

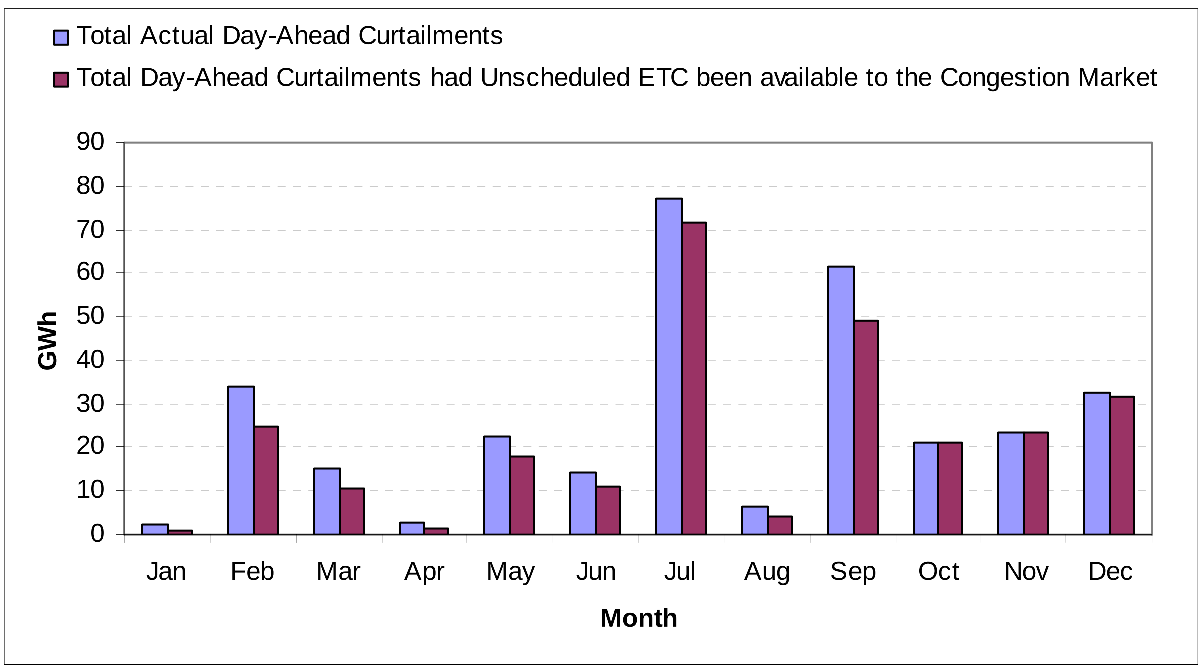
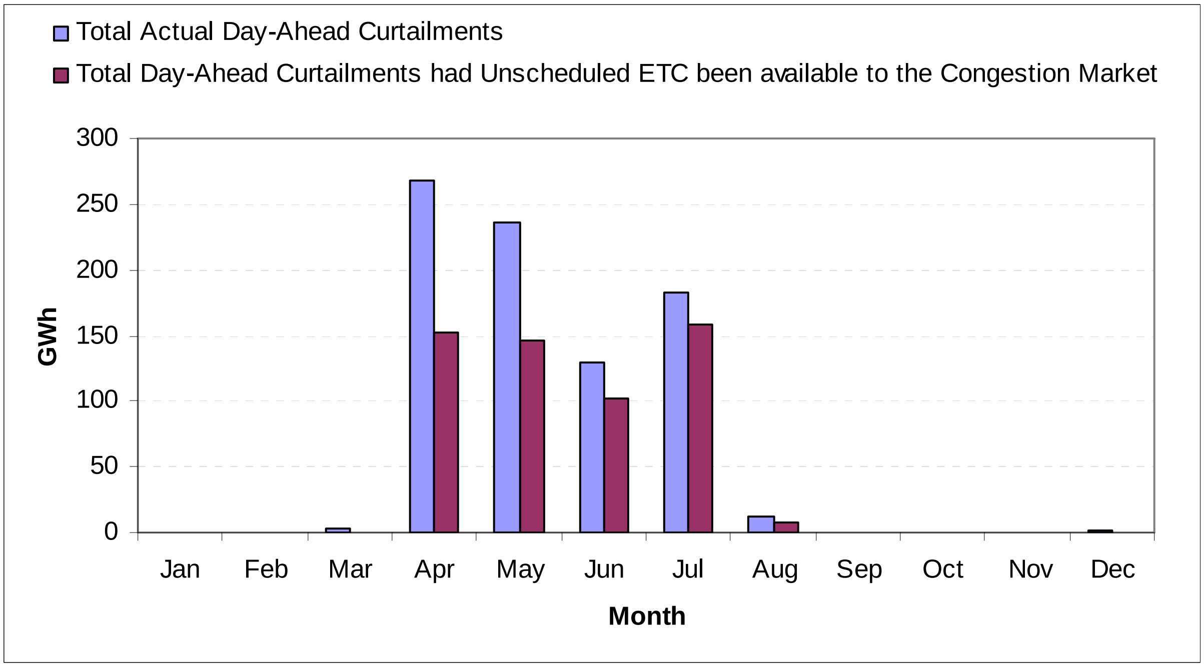


Figure 5.6 Phantom Congestion on the Pacific AC Inter-tie (2006)



Phantom congestion in recent years (2005-2006) has also been reduced from prior levels due to several ETCs that expired in 2005 and late 2004. Specifically, for SCE, 1,568 MW of ETC capacity expired on December 31, 2004, 900 MW expired on January 1, 2005, and 110 MW expired on May 14, 2005.

Treatment of ETCs under MRTU

The CAISO has long recognized the phantom congestion problem created by unscheduled ETCs in the Day Ahead Market and has tried to address this issue in its market re-design effort. Treatment of ETCs under the CAISO's Market Redesign and Technology Upgrade (MRTU) is an especially important issue since some ETCs will remain in effect upon implementation of MRTU in February of 2008. In sum, these encumbrances represent transmission capacity of approximately 16,000 MW, or capacity sufficient to meet 32 percent of the CAISO's 2006 peak load of 50,270 MW. Following an extensive stakeholder process in 2004, the CAISO filed with the FERC on December 8, 2004, its Proposed Conceptual Treatment of Existing Transmission Contracts under the CAISO's Amended Comprehensive Market Design Proposal. The proposal resolved how ETCs would be scheduled, validated, and settled under LMP. Responding to the CAISO's proposal, the FERC issued a "Guidance Order on Conceptual Proposal for Honoring of Existing Transmission Contracts" on February 10, 2005. In this order, the FERC approved in principle certain elements of the ETC proposal, provided guidance and requested additional information and explanation of other elements. More specifically, the FERC accepted the CAISO's conceptual proposal to set aside capacity associated with an ETC within the CAISO's control area to the extent that it is scheduled in the Day Ahead Market and to fully honor all valid schedule changes in post-day-ahead markets. Also the FERC accepted the CAISO's proposal to continue to set aside unscheduled capacity over the inter-ties, but not for internal interfaces. The FERC agreed that this will make additional capacity available in the Day Ahead and subsequent markets for use by other users of the system, reduce the likelihood and magnitude of phantom congestion, and promote the convergence of day-ahead and real-time prices. The

FERC reaffirmed this decision in its September 21, 2006 MRTU Order on the CAISO MRTU Tariff filing.

5.2 Firm Transmission Rights Market Performance

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.

The CAISO does not require that FTR owners be CAISO Scheduling Coordinators (SCs). FTRs may be purchased by any qualified bidder purely as an investment to enable the owner to receive a stream of income from the congestion usage revenues. In order to be used in scheduling, however, an FTR must be assigned to one of the SCs. In addition, an owner may resell the FTR or the scheduling rights may be unbundled from the revenue rights and sold or transferred to another party. All these sales, transfers or assignments are considered “secondary market transactions” and must be recorded in the CAISO Secondary Registration System (SRS).

5.2.1 Primary Auction Results

The CAISO creates a primary market for FTRs by auctioning them each year for a 12-month period beginning in April and ending in March. The primary FTR auction for the 2005/2006 FTR auction year (from April 1, 2005, to March 31, 2006) occurred in February 2005. The primary FTR auction for the 2006/2007 FTR auction year (from April 1, 2006, to March 31, 2007) occurred in February 2006. The FTR Auction is a simultaneous, multi-round clearing price auction conducted separately and independently across specified CAISO inter-zonal interfaces. The FTR Auction proceeds are distributed to Participating Transmission Owners (PTOs), based upon their respective ownership interest in each auctioned path.

Owners of FTRs can use their FTRs as a hedge against congestion costs. The FTRs also entitle the 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 the registered FTR Holder to certain priorities (in the Day Ahead Market) for the scheduling of energy across a congested inter-zonal interface.

Table 5.5 and Table 5.6 provide summaries of the 2005-2006 and 2006-2007 FTR primary auction results, respectively. Total revenue earned in the 2006-2007 primary auction was approximately $104 million, compared to $94 million in the 2005-2006 primary auction.

In the 2006-2007 primary auction, FTRs on 29 directional branch groups were auctioned. In total, the CAISO successfully auctioned 14,452 MW of FTRs, compared to 12,063 MW of FTRs auctioned in 2005-2006 primary FTR auction. On the branch group level, auction revenue on Palo Verde in the import direction increased from $25 million in 2005-06 to $27.2 million in 2006-07. Other notable changes from the 2005-06 primary auction included an increase in auction revenues on PACI from $16.5 million to $28 million and an increase in auction revenues on NOB from $3.5 million to $9.4 million. The auction clearing price for PACI also increased dramatically in the 2006-07 auction to $41,052/MW compared to $18,609/MW in the prior year. These increases likely reflected expectations of high imports into California from the Pacific Northwest - given the abundance of snow pack that was evident at the time of the auction (February 2006). Conversely, auction revenues on two major southwest branch groups, Mead and Eldorado declined in the 2006-07 primary auction.

Table 5.5 Summary of 2005-2006 FTR Auction Results (FTRs - April 1, 2005 through March 31, 2006)

Branch Group	Direction	Total FTRs Sold (MW)	Auction Clearing Price ($/MW)	Auction Revenue ($)
BLYTHE BG	Import (LC2-SP15)	177	$6,714	$1,188,452
BLYTHE BG	Export (SP15-LC2)	38	$100	$3,800
CFE BG	Import (MX-SP15)	200	$265	$53,000
ELDORADO BG	Import (AZ2-SP15)	743	$27,701	$20,581,962
ELDORADO BG	Export (SP15-AZ2)	445	$100	$44,500
IID – SCE BG	Import (II1-SP15)	600	$295	$177,000
IID - SDGE BG	Import (II2-SP15)	62	$190	$11,780
IID - SDGE BG	Export (SP15-II2)	62	$145	$8,990
MEAD BG	Import (LC1-SP15)	597	$18,174	$10,850,093
MEAD BG	Export (SP15-LC1)	637	$210	$133,770
NOB BG	Import (NW3-SP15)	169	$20,790	$3,513,483
NOB BG	Export (SP15-NW3)	173	$1,840	$318,320
PACI BG	Import (NW1-NP15)	890	$18,609	$16,562,330
PACI BG	Export (NP15-NW1)	573	$240	$137,520
PALOVRDE BG	Import (AZ3-SP15)	910	$27,425	$24,957,041
PALOVRDE BG	Export (SP15-AZ3)	683	$100	$68,300
PARKER BG	Import (LC3-SP15)	130	$705	$91,650
PATH 15 BG	Import (ZP26-NP15)	1807	$3,056	$5,522,626
PATH 26 BG	Export (ZP26-SP15)	1,464	$6,637	$9,716,641
SLVRPK BG	Import (SR3-SP15)	10	$540	$5,400
SLVRPK BG	Export (SP15-SR3)	10	$180	$1,800
VICTRVL BG	Export (SP15-LA4)	439	$100	$43,900
VICTRVL BG	Import (LA4-SP15)	1244	$100	$124,400
Total		**12,063**		**$94,116,759**

Table Column Definition:
Auction Clearing Price: This is the market-clearing price in $/MW per year. For the paths with seed price > $100/MW per year, the comparison of the Auction Clearing Price and Seed Price* 5 indicates the extent to which the bidders value the FTRs on the particular path and direction compared to the congestion revenues generated last year.
Total FTR Sold: This is the final MW clearing the auction. The difference between Total FTR Auctioned and Final MW sold can be either due to some FTRs not sold or the residual FTR allocation option exercised in the auction.
Auction Revenue: This is equal to the product of Auction Clearing Price and Final MW Sold.

Table 5.6 Summary of 2006-2007 FTR Auction Results (for FTRs valid April 1, 2006 through March 31, 2007)

Branch Group	Direction	Total FTRs Sold (MW)	Auction Clearing Price ($/MW)	Auction Revenue ($)
BLYTHE	Import	140	$24,498	$3,429,720
BLYTHE	Export	122	$100	$12,200
CFE	Import	345	$130	$44,850
CTNWDRDMT	Import	285	$100	$28,500
CTNWDRDMT	Export	235	$100	$23,500
CTNWDWAPA	Import	498	$100	$49,800
CTNWDWAPA	Export	498	$100	$49,800
ELDORADO	Import	536	$24,531	$13,148,616
ELDORADO	Export	536	$245	$131,320
IID-SCE	Import	600	$330	$198,000
IID-SDGE	Import	62	$145	$8,990
IID-SDGE	Export	31	$100	$3,100
MEAD	Import	597	$6,535	$3,901,395
MEAD	Export	543	$100	$54,300
NOB	Import	472	$19,850	$9,369,200
NOB	Export	454	$250	$113,500
PACI	Import	684	$41,052	$28,079,568
PACI	Export	399	$100	$39,900
PALOVRDE	Import	1,230	$22,114	$27,200,220
PALOVRDE	Export	749	$100	$74,900
PARKER	Import	160	$280	$44,800
PATH15	South to North	1,730	$5,779	$9,997,670
PATH26	North to South	1,315	$5,692	$7,484,980
RNCHLAKE	Import	310	$100	$31,000
RNCHLAKE	Export	261	$100	$26,100
SILVERPK	Import	17	$100	$1,700
SILVERPK	Export	8	$100	$800
VICTVL	Import	1,355	$100	$135,500
VICTVL	Export	280	$100	$28,000
Totals		**14,452**		$103,711,929

5.2.2 Concentration of FTR Ownership and Control

As in the previous auction, one discernible pattern in the FTR auction results was that Investor Owned Utilities (IOUs) acquired most FTRs on branch groups that are likely to be congested. For instance, Pacific Gas & Electric won 78 and 99 percent of FTRs on PACI (import) and Path 15 (south-to-north), respectively. Similarly, Southern California Edison won 100 and 97 percent of FTRs on El Dorado (import) and Palo Verde (import), respectively. As the principal transmission owners of these paths, the utilities are also the recipients of the auction revenues. This allows them to bid very aggressively to ensure they acquire the quantity of FTRs they require to serve their retail customers without significant exposure to the spot congestion markets. This may have an inflationary effect on FTR auction clearing prices.

Table 5.7 FTR Concentration as of April 2006*

Branch Group	Direction	Owner Name	Percent Conc.	Max FTRs Owned (MW)	Total FTRs Auctioned (MW)
ADLANTOSP_BG	Export	City of Pasadena	32.3%	162	502
BLYTHE _BG	Export	Morgan Stanley Capital Group, Inc.	59.0%	72	122
BLYTHE _BG	Export	Susquehanna Energy Products-SEPC	41.0%	50	122
CTNWDRDMT_BG	Export	Morgan Stanley Capital Group, Inc.	68.1%	160	235
CTNWDWAPA_BG	Export	Morgan Stanley Capital Group, Inc.	79.9%	398	498
ELDORADO _BG	Export	Morgan Stanley Capital Group, Inc.	27.1%	145	536
ELDORADO _BG	Export	Public Service Company of Colorado	63.6%	341	536
GONDIPPDC_BG	Export	City of Anaheim	46.2%	6	13
GONDIPPDC_BG	Export	City of Pasadena	53.8%	7	13
IID-SDGE _BG	Export	Morgan Stanley Capital Group, Inc.	100.0%	31	31
IPPDCADLN_BG	Export	City of Anaheim	52.4%	247	471
IPPDCADLN_BG	Export	City of Riverside	30.1%	142	471
MCCLMKTPC_BG	Export	City of Anaheim	33.2%	228	686
MEAD _BG	Export	Morgan Stanley Capital Group, Inc.	55.1%	318	577
MEADMKTPC_BG	Export	City of Anaheim	41.8%	110	263
MEADMKTPC_BG	Export	City of Vernon	28.5%	75	263
MEADTMEAD_BG	Export	City of Anaheim	60.4%	110	182
MEADTMEAD_BG	Export	City of Vernon	25.8%	47	182
MKTPCADLN_BG	Export	City of Anaheim	27.9%	118	423
MKTPCADLN_BG	Export	City of Riverside	27.9%	118	423
MONAIPPDC_BG	Export	City of Anaheim	54.4%	249	458
MONAIPPDC_BG	Export	City of Riverside	29.5%	135	458
PACI _BG	Export	Morgan Stanley Capital Group, Inc.	56.1%	224	399
PALOVRDE _BG	Export	Morgan Stanley Capital Group, Inc.	80.6%	624	774
PATH26 _BG	North-to-South	Pacific Gas & Electric Company-PCG2	28.7%	377	1315
PATH26 _BG	North-to-South	San Diego Gas & Electric, Merchant	35.4%	465	1315
RNCHLAKE _BG	Export	Morgan Stanley Capital Group, Inc.	90.4%	236	261
SILVERPK _BG	Export	Morgan Stanley Capital Group, Inc.	100.0%	8	8
SYLMAR-AC_BG	Export	City of Azusa	40.0%	10	25
SYLMAR-AC_BG	Export	City of Banning	60.0%	15	25
VICTVL _BG	Export	Morgan Stanley Capital Group,	100.0%	280	280

Branch Group	Direction	Owner Name	Percent Conc.	Max FTRs Owned (MW)	Total FTRs Auctioned (MW)
		Inc.			
WSTWGMEAD_BG	Export	City of Anaheim	37.3%	47	126
WSTWGMEAD_BG	Export	City of Pasadena	26.2%	33	126
ADLANTOSP_BG	Import	City of Anaheim	43.3%	449	1036
ADLANTOSP_BG	Import	City of Riverside	30.2%	313	1036
BLYTHE _BG	Import	FPL Energy Power Marketing, Inc.	57.1%	80	140
BLYTHE _BG	Import	Morgan Stanley Capital Group, Inc.	42.9%	60	140
CFE _BG	Import	Coral Power, LLC - CRLP	29.0%	100	345
CFE _BG	Import	Morgan Stanley Capital Group, Inc.	46.7%	161	345
CTNWDRDMT_BG	Import	Morgan Stanley Capital Group, Inc.	56.1%	160	285
CTNWDRDMT_BG	Import	British Columbia Power Exchange	35.1%	100	285
CTNWDWAPA_BG	Import	Morgan Stanley Capital Group, Inc.	79.9%	398	498
ELDORADO _BG	Import	Southern California Edison Company	100.0%	536	536
GONDIPPDC_BG	Import	City of Anaheim	57.1%	28	49
GONDIPPDC_BG	Import	City of Pasadena	26.5%	13	49
IID-SCE _BG	Import	Southern California Edison Company	76.7%	460	600
IID-SDGE _BG	Import	Morgan Stanley Capital Group, Inc.	50.0%	31	62
IID-SDGE _BG	Import	Susquehanna Energy Products-SEPC	50.0%	31	62
IPPDCADLN_BG	Import	City of Anaheim	52.4%	339	647
IPPDCADLN_BG	Import	City of Riverside	30.1%	195	647
MCCLMKTPC_BG	Import	City of Anaheim	33.2%	228	686
MEAD _BG	Import	Southern California Edison Company	36.9%	246	667
MEADMKTPC_BG	Import	City of Anaheim	41.8%	110	263
MEADMKTPC_BG	Import	City of Vernon	28.5%	75	263
MEADTMEAD_BG	Import	City of Anaheim	60.4%	110	182
MEADTMEAD_BG	Import	City of Vernon	25.8%	47	182
MONAIPPDC_BG	Import	City of Anaheim	54.3%	280	516
MONAIPPDC_BG	Import	City of Riverside	29.7%	153	516
NOB _BG	Import	British Columbia Power Exchange	26.6%	176	661
PACI _BG	Import	Pacific Gas & Electric Company-PCG2	78.1%	534	684
PALOVRDE _BG	Import	Southern California Edison Company	97.3%	1221	1255
PARKER _BG	Import	FPL Energy Power Marketing, Inc.	99.4%	159	160
PATH15 _BG	South-to-	Pacific Gas & Electric	98.6%	1705	1730

Branch Group	Direction	Owner Name	Percent Conc.	Max FTRs Owned (MW)	Total FTRs Auctioned (MW)
	North	Company-PCG2			
RNCHLAKE _BG	Import	Morgan Stanley Capital Group, Inc.	91.9%	285	310
SILVERPK _BG	Import	Morgan Stanley Capital Group, Inc.	47.1%	8	17
SILVERPK _BG	Import	British Columbia Power Exchange	52.9%	9	17
SYLMAR-AC_BG	Import	City of Azusa	57.1%	20	35
SYLMAR-AC_BG	Import	City of Banning	42.9%	15	35
VICTVL _BG	Import	Morgan Stanley Capital Group, Inc.	49.2%	666	1355
WSTWGMEAD_BG	Import	City of Anaheim	37.3%	47	126
WSTWGMEAD_BG	Import	City of Pasadena	26.2%	33	126

* Only FTR ownership concentrations at or more than 25 percent are reported in this table.

5.2.3 2006-07 FTR Market Performance

FTR Scheduling

FTRs can be used to hedge against high congestion prices and establish scheduling priority in the Day Ahead Market. As shown in Table 5.8, a high percentage of FTRs were scheduled only on a few paths (95 percent on Eldorado, 72 percent on IID-SCE and 73 percent on IPPDCADLN). SCE and municipals primarily own the FTRs on these paths. In the 2006-07 FTR cycle, the average amount of FTRs scheduled was low. On average, only 23.4 percent of the total FTRs were scheduled in the Day Ahead Market, slightly lower than the 24.3 percent in the 2005-06 FTR cycle.

Table 5.8 FTR Scheduling Statistics, April 1 – December 31, 2006*

Branch Group	Direction	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Schedule - Dir
BLYTHE _BG	Import	140	0	80	80	0%
ELDORADO _BG	Import	536	508	536	536	95%
IID-SCE _BG	Import	600	435	468	443	72%
IPPDCADLN_BG	Import	647	470	558	307	73%
MEAD _BG	Import	667	92	318	128	14%
MEADTMEAD_BG	Import	182	12	57	38	6%
MKTPCADLN_BG	Import	423	14	102	85	3%
MONAIPPDC_BG	Import	544	61	107	55	11%
NOB _BG	Import	661	93	328	83	14%
PALOVRDE _BG	Import	1255	449	649	615	36%
PARKER _BG	Import	160	0	159	159	0%
VICTVL _BG	Import	1355	1	75	75	0%
WSTWGMEAD_BG	Import	126	30	57	28	24%
GONDIPPDC_BG	Export	15	2	13	13	11%
MEAD _BG	Export	577	0	25	25	0%
MKTPCADLN_BG	Export	423	0	25	25	0%
MONAIPPDC_BG	Export	478	4	85	85	1%
NOB _BG	Export	632	26	145	108	4%
PALOVRDE _BG	Export	774	0	25	25	0%
PATH26 _BG	North-to-South	1315	494	842	465	38%

* Only those paths on which 1 percent or more of FTRs were attached are listed.

FTR Revenue

The current FTR market cycle begins on April 1, 2006, and ends on March 31, 2007. Table 5.9 summarizes the FTR revenues from April 1, 2006, to January 31, 2007.

During the current FTR cycle, six paths (Mead (import), NOB (import), Palo Verde (import), Parker (import), Path 26 (north-to-south), and Ranch Lake (export)) had total pro-rated FTR revenue greater than their auction prices. Most notably, Mead (import) and Parker (import) had pro-rated revenues equal to 769 percent and 846 percent of the auction price. However, pro-rated FTR revenues on most paths were well below the auction price. This is not surprising. As mentioned earlier, the FTR holders of major paths are also transmission owners. The FTR auction revenues are used to reduce the Transmission Revenue Requirement (TRR). As a result, the FTR purchase cost for these entities is to a large extent offset by a corresponding reduction in the TRR. Also, besides the FTR revenue, the FTR provides additional benefits to the holders. Schedules with FTR rights are entitled to scheduling priority in the Day Ahead Market and FTRs can serve as insurance to hedge against possible high congestion charges.

Table 5.9 FTR Revenue Statistics ($/MW) (April 2006 – January 2007)

Branch Group	Direction	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Cum. Net $/MW FTR Rev.	Prorated Net $/MW FTR Rev.	Primary Auction Price	Value Ratio
ADLANTOSP	Import	$ -	$ -	$ -	$ 0	$ 880	$ 2,562	$ 1,806	$ 3,245	$ 300	$ 1,311	$ 10,104	$ 12,124	N/A	N/A
BLYTHE	Import	$ -	$ -	$ -	$ 6	$ 251	$ 315	$ 26	$ 649	$ 37	$ 0	$ 1,284	$ 1,541	$ 24,498	6%
CFE	Import	$ -	$ -	$ -	$ -	$ -	$ 21	$ -	$ -	$ -	$ -	$ 21	$ 25	$ 130	19%
ELDORADO	Import	$ 244	$ 0	$ -	$ -	$ 7	$ 140	$ 1,955	$ 206	$ 135	$ 394	$ 3,082	$ 3,698	$ 24,531	15%
IID-SCE	Import	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	$ 51	$ 26	$ 79	$ 95	$ 330	29%
IPPDCADLN	Import	$ 473	$ 1,212	$ 630	$ 148	$ 499	$ 11,867	$ 477	$ 2,223	$ 814	$ 469	$ 18,812	$ 22,574	N/A	N/A
MEAD	Import	$ 227	$ 15	$ 34	$ 1,928	$ 6,366	$ 18,489	$ 2,676	$ 5,460	$ 2,368	$ 4,319	$ 41,883	$ 50,259	$ 6,535	769%
MKTPCADLN	Import	$ -	$ -	$ -	$ -	$ 214	$ 685	$ 509	$ 709	$ 360	$ 831	$ 3,308	$ 3,970	N/A	N/A
NOB	Import	$ 21,580	$ 2,935	$ 7,577	$ 4,634	$ 46	$ -	$ -	$ 0	$ 61	$ 817	$ 37,650	$ 45,180	$ 19,850	228%
PACI	Import	$ 10,598	$ 2,942	$ 5,987	$ 2,066	$ 4	$ 4	$ 1	$ 15	$ 72	$ 442	$ 22,132	$ 26,558	$ 41,052	65%
PALOVRDE	Import	$ 393	$ 1,214	$ 4,158	$ 7,968	$ 513	$ 3,431	$ 2,210	$ 4,121	$ 9,595	$ 6,875	$ 40,479	$ 48,575	$ 22,114	220%
PARKER	Import	$ -	$ -	$ -	$ 52	$ 0	$ 128	$ 109	$ 1,603	$ 82	$ -	$ 1,975	$ 2,370	$ 280	846%
PATH15	South-to-North	$ -	$ -	$ -	$ -	$ -	$ -	$ 54	$ 234	$ 1,097	$ 113	$ 1,498	$ 1,797	$ 5,779	31%
SILVERPK	Import	$ -	$ 12	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 20	$ 25	$ 100	25%
WSTWGMEAD	Import	$ 502	$ 89	$ 1	$ 230	$ 325	$ 600	$ 1,086	$ 249	$ 32	$ 111	$ 3,224	$ 3,869	N/A	N/A
BLYTHE	Export	$ -	$ -	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13	$ 15	$ 100	15%
IID-SDGE	Export	$ -	$ -	$ -	$ 30	$ 30	$ -	$ -	$ -	$ -	$ -	$ 60	$ 72	$ 100	72%
MONAIPPDC	Export	$ -	$ -	$ -	$ 33	$ 15	$ -	$ -	$ -	$ -	$ -	$ 48	$ 57	N/A	N/A
NOB	Export	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 128	$ -	$ -	$ 128	$ 153	$ 250	61%
PATH26	North-to-South	$ 5,596	$ 882	$ 185	$ 649	$ 0	$ 49	$ -	$ -	$ -	$ -	$ 7,361	$ 8,833	$ 5,692	155%
RNCHLAKE	Export	$ -	$ -	$ 120	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 120	$ 144	$ 100	144%
VICTVL	Export	$ -	$ -	$ 15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15	$ 18	$ 100	18%

FTR Trades in the Secondary Markets

In California, the successful bidders in the FTR primary auctions are allowed to conduct further FTR trades in the secondary markets. However, as shown in Table 5.10, the FTR transactions in the secondary markets have been minimal during the past FTR cycle. One notable exception was a 128 MW trade of Mead-import FTRs on March 28, 2006. There were a total of 18 cases of changes in ownership of FTRs in the 2006 cycle (determined by different SC_ID association over time). However, all but one of these exchanges (128 MW Mead exchange) occurred between Southern Participating Transmission Owners (SPTOs) (i.e., the City of Pasadena, the City of Anaheim, the City of Azusa, the City of Banning, or the City of Riverside) and the CAISO, due to either the transfer of FTRs owned by SPTOs to the CAISO, or the revision of the SPTOs' entitlements.

Table 5.10 FTR Trades in the Secondary Market (April 2006 - December 2006)

Branch Group	Direction	Date of Trade	Buyer	Seller	Quantity Sold (MW)	First Effective Date	Last Effective Date
GONDIPPDC_BG	Export	14-Sep-06	ANHM	CISO	1	25-Sep-06	31-Mar-07
MEADMKTPC_BG	Export	26-Jan-07	ANHM	CISO	45	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Export	29-Jan-07	RVSD	CISO	5	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Export	29-Jan-07	AZUA	CISO	1	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Export	29-Jan-07	BAN1	CISO	1	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Export	29-Jan-07	VERN	CISO	30	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Export	29-Jan-07	PASA	CISO	24	1-Feb-07	31-Mar-07
MONAIPPDC_BG	Export	11-Sep-06	RVSD	CISO	6	25-Sep-06	31-Mar-07
MONAIPPDC_BG	Export	13-Sep-06	ANHM	CISO	11	25-Sep-06	31-Mar-07
NOB _BG	Export	16-Mar-06	RVSD	CISO	23	1-Apr-06	31-Mar-07
GONDIPPDC_BG	Import	14-Sep-06	ANHM	CISO	1	25-Sep-06	31-Mar-07
MEAD _BG	Import	28-Mar-06	MNEV	MRNT	128	1-Apr-06	31-Mar-07
MEADMKTPC_BG	Import	26-Jan-07	ANHM	CISO	45	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Import	29-Jan-07	RVSD	CISO	5	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Import	29-Jan-07	AZUA	CISO	1	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Import	29-Jan-07	BAN1	CISO	1	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Import	29-Jan-07	VERN	CISO	30	1-Feb-07	31-Mar-07
MEADMKTPC_BG	Import	29-Jan-07	PASA	CISO	24	1-Feb-07	31-Mar-07
MONAIPPDC_BG	Import	11-Sep-06	RVSD	CISO	9	25-Sep-06	31-Mar-07
MONAIPPDC_BG	Import	13-Sep-06	ANHM	CISO	15	25-Sep-06	31-Mar-07
NOB _BG	Import	16-Mar-06	RVSD	CISO	23	1-Apr-06	31-Mar-07
PALOVRDE _BG	Import	16-Mar-06	AZUA	CISO	10	1-Apr-06	31-Mar-07
PALOVRDE _BG	Import	28-Mar-06	BAN1	CISO	15	1-Apr-06	31-Mar-07

6 Intra-Zonal Congestion

6.1 Introduction/Background

Scheduling Coordinators (SCs) submit day-ahead/hour-ahead generation and load schedules to the CAISO. Due to differences in the price and availability of power in different locations, these schedules vary daily and, collectively, may exceed the transfer capability of grid facilities within the congestion zones. However, the CAISO's Day Ahead and Hour Ahead Congestion Management Markets only manage congestion between zones, not within zones. This allows SCs to submit day-ahead/hour-ahead schedules that require transmission within a zone that is not physically feasible, and, as a consequence, creates the need for CAISO operators to have to manage intra-zonal congestion in real-time. Managing large amounts of intra-zonal congestion in real-time creates operational and reliability challenges and can result in significant costs.

Intra-zonal congestion costs are comprised of three components:

1) Minimum Load Cost Compensation (MLCC).[1] These costs result from generating units that are committed to operate on a day-ahead basis under the provisions of the Must-Offer Obligation in order to mitigate anticipated intra-zonal congestion.[2]

2) Costs from Reliability Must Run (RMR) real-time dispatches that are the first response to intra-zonal congestion.

3) Costs of Out-of-Sequence (OOS) dispatches.

Intra-zonal congestion most frequently occurs in load pockets, or areas where load is concentrated, where transmission within the zone is not sufficient to allow access to competitively-priced energy. In some cases, the CAISO must also decrement generation outside the load pocket to balance the incremental generation dispatched within it. Intra-zonal congestion can also occur due to pockets in which generation is clustered together, without the transmission necessary for the energy to flow out of that pocket to load. In both cases, the absence of sufficient transmission access to an area means that the CAISO has to resolve the problem locally, either by incrementing generation within a load pocket or by decrementing it in a generation pocket. Such congestion is inefficient if, over the course of congestion in that area, the market costs due to the transmission congestion (i.e., the cost imposed by the fact that load cannot be served by the lowest-cost supplier(s), and instead must be served by higher-cost suppliers) exceed the cost of a transmission upgrade that could alleviate the congestion.

Typically, there is limited competition within load or generation pockets, since the bulk of generation within such pockets is owned by just one or two suppliers. As a result, intra-zonal

[1] MLCC payments are cost-based and are calculated as variable cost for providing the minimum load energy plus a $6/MWh O&M adder.

[2] Pursuant to Amendment 60, MLCC costs are categorized into three categories (system, zonal and local), which reflect the primary reason the unit was denied a must-offer waiver. Both zonal and local MLCC costs are included as the MLCC component of intra-zonal costs.

congestion often coexists with locational market power. Methods to resolve intra-zonal congestion are designed to limit the ability of suppliers to exercise local market power.

The CAISO's current method for dealing with incremental intra-zonal congestion involves a combination of steps and operating procedures. On a day-ahead basis, the CAISO often constrains-on or commits long-start thermal units through the must-offer waiver (MOW) process in return for minimum load cost payments and/or Resource Adequacy (RA) capacity payments. This forward unit commitment process helps to mitigate intra-zonal congestion that may be anticipated based upon day-ahead schedules submitted by market participants. Units required to operate under the MOW process are typically dispatched at minimum load levels. They are then required to bid all unloaded capacity into the CAISO real-time market.[3] In real-time, the CAISO dispatches real-time energy bids in merit order (based on bid price) in order to balance overall system or zonal loads and generation. If dispatch of in-sequence bids does not resolve intra-zonal congestion in real-time, the CAISO can mitigate intra-zonal congestion in three ways:

- First, the CAISO may dispatch available RMR capacity to mitigate congestion;
- Second, should energy from RMR units be insufficient, the CAISO may dispatch other units by calling real-time energy bids Out-of -Sequence (OOS);[4]
- Finally, if insufficient market bids exist to mitigate intra-zonal congestion, the CAISO may call units Out-of-Market (OOM).

Units incremented OOS to mitigate intra-zonal congestion are paid the higher of their bid price or the zonal market clearing price (MCP). They do not set the real-time market clearing price. Units decremented OOS to mitigate intra-zonal congestion are charged the lower of their decremental reference price or the zonal market-clearing price. They also do not set the real-time market clearing price. Inter-tie bids taken OOS are settled on an as-bid basis.

In addition, OOS bids are subject to local market power mitigation. Specifically, incremental OOS dispatches are subject to a conduct test where accepted OOS bids priced greater than the minimum of $50 or 200 percent above the interval MCP are mitigated to their reference price for that OOS dispatch and are settled at the greater of the mitigated bid price or the interval MCP. To the extent decremental bids are dispatched OOS for intra-zonal congestion, such dispatches will be based on decremental reference levels rather than market bids and will be settled based on the lower of the unit's decremental reference price and the real-time interval MCP.

6.2 Points of Intra-Zonal Congestion

Both NP15 and SP15 experienced intra-zonal congestion in 2006. As in 2005, the largest congestion point within NP15 was the Geysers-Cortina area in the northern San Francisco Bay Area. There was also congestion in the Sacramento River Delta region, a large generation pocket where the Pittsburg, Contra Costa, Delta, and Los Mendanos power plants are located.

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[3] Available thermal units within the CAISO Control Area are subject to the Must-Offer Obligation (MOO) whereby incremental energy bids are automatically inserted for them if they fail to do so themselves. There is no MOO for decremental energy bids.

[4] The term "out-of-sequence" refers to the fact that such dispatches require the CAISO, when incrementing (or decrementing) generation, to bypass lower (or higher) priced, in-sequence, real-time bids to find a unit whose grid location enables it to mitigate a particular intra-zonal congestion problem.

Intra-zonal congestion within SP15 was predominately at locations where intra-zonal congestion has been an issue in recent years. These include the following:

- The Southern California Import Transmission (SCIT) nomogram, a technical limit on the instantaneous import of power into the SP26 region from Northern California and other neighboring areas. This congestion can be mitigated using either intra-zonal (real-time out-of-sequence dispatch) or inter-zonal (day-ahead dispatch) congestion management procedures.

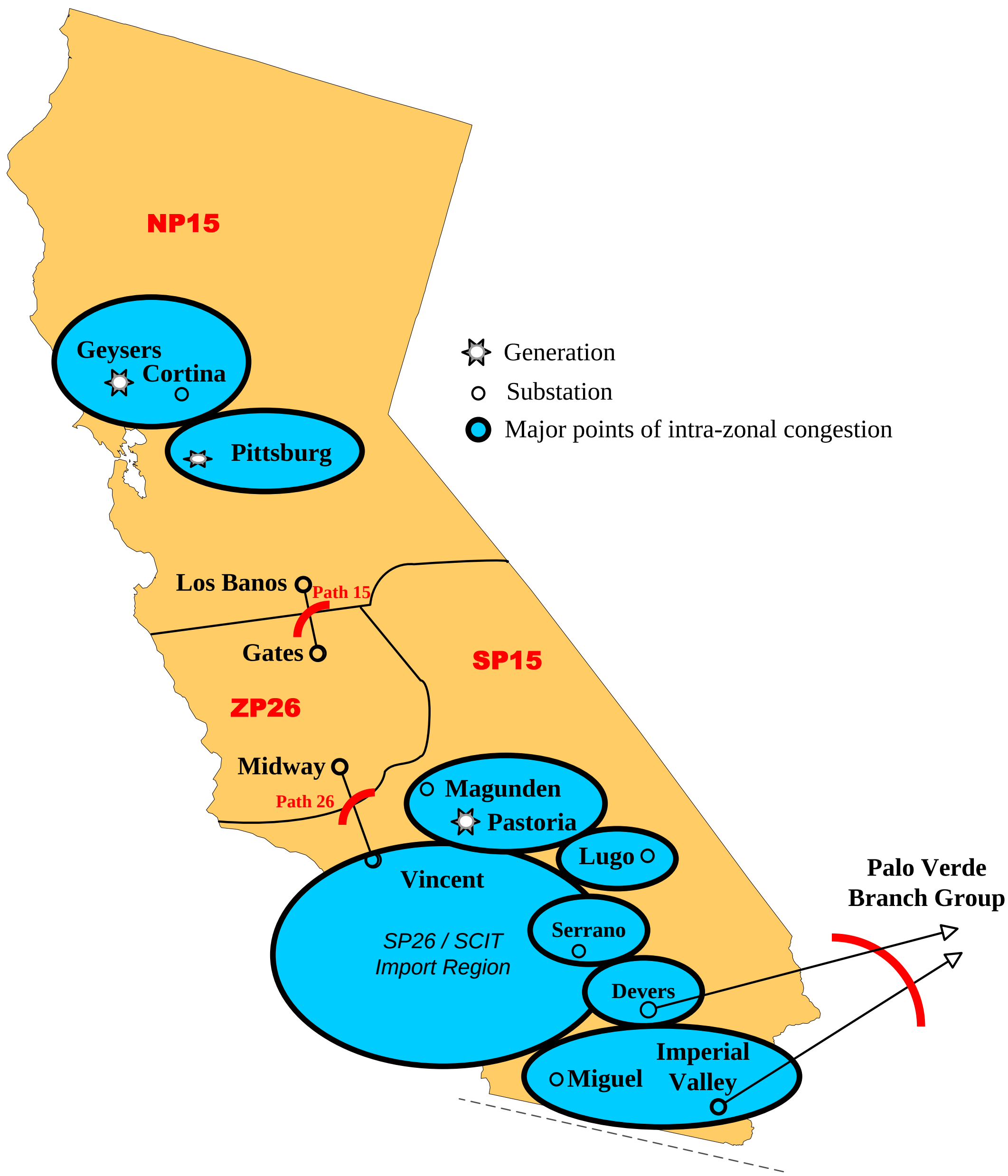
- The Miguel and Imperial Valley substations, resulting from the transmission of power to Southern California load from generation facilities located in Mexicali, Baja California, Mexico, and imports on the Southwest Power Link (i.e., North Gila to Imperial Valley).

- The Magunden/Pastoria region, near Bakersfield. The large generation facilities of the Big Creek Project, the largest hydroelectric project in Southern California, and the Pastoria generating facility, located in Lebec, interconnect with the Southern California grid at the same location, and often result in intra-zonal congestion.

- South of the Lugo substation, near Hesperia. Power from the Hoover Dam in Nevada and new combined-cycle facilities in California interconnect to the Southern California grid at this point, often resulting in congestion.

Figure 6.1 provides a representation of the CAISO Control Area's key intra-zonal congestion locations in 2006.

Figure 6.1 Key Points of Intra-Zonal Congestion



6.3 Intra-Zonal Congestion Management Costs

Overall, intra-zonal congestion has declined substantially in recent years, due largely to transmission upgrades and the installation of new generation. Estimated intra-zonal congestion management costs totaled $207 million in 2006, compared to $222 million in 2005, and $426 million in 2004. Of the costs incurred in 2006, 58 percent were incurred between January and

April, during the completion of several key transmission upgrade projects. Once these projects were completed, congestion costs declined substantially.

Measurable intra-zonal congestion management costs include three components: Minimum-Load Cost Compensation (MLCC) for intra-zonal (non-system) reasons, reliability must-run variable costs associated with real-time congestion management, and out-of-sequence redispatch costs. Table 6.1 shows total estimated intra-zonal congestion management costs for 2004 through 2006 by the three components discussed above. While MLCC costs and Real-time Redispatch costs declined in 2006 by approximately $5 million and $12 million, respectively, these savings were offset to some extent by an increase in real-time RMR dispatch costs of $8 million.

Table 6.1 Total Estimated Intra-Zonal Congestion Costs for 2004-2006 ($MM)[5]

	MLCC Costs			RT RMR Costs			RT Redispatch Costs			Total		
Month	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**	**2004**	**2005**	**2006**
Jan	$ 12	$ 8	$ 10	$ 3	$ 3	$ 13	$ 4	$ 6	$ 4	$ 19	$ 17	$ 27
Feb	$ 13	$ 4	$ 8	$ 4	$ 3	$ 15	$ 7	$ 3	$ 2	$ 24	$ 10	$ 25
Mar	$ 20	$ 3	$ 11	$ 4	$ 5	$ 13	$ 8	$ 3	$ 3	$ 32	$ 11	$ 27
Apr	$ 18	$ 6	$ 27	$ 4	$ 5	$ 8	$ 5	$ 3	$ 6	$ 27	$ 14	$ 41
May	$ 22	$ 14	$ 12	$ 3	$ 5	$ 3	$ 4	$ 2	$ 1	$ 29	$ 21	$ 16
Jun	$ 25	$ 7	$ 15	$ 3	$ 2	$ 4	$ 2	$ 0	$ 0	$ 30	$ 9	$ 19
Jul	$ 29	$ 13	$ 14	$ 6	$ 5	$ 2	$ 11	$ 1	$ 0	$ 46	$ 19	$ 17
Aug	$ 29	$ 14	$ 5	$ 5	$ 9	$ 3	$ 15	$ 1	$ 0	$ 49	$ 24	$ 8
Sep	$ 23	$ 8	$ 3	$ 4	$ 6	$ 2	$ 12	$ 3	$ 0	$ 39	$ 17	$ 5
Oct	$ 21	$ 13	$ 1	$ 4	$ 8	$ 3	$ 18	$ 4	$ 1	$ 43	$ 25	$ 5
Nov	$ 29	$ 12	$ 1	$ 5	$ 5	$ 6	$ 9	$ 6	$ 0	$ 43	$ 23	$ 7
Dec	$ 33	$ 11	$ 2	$ 4	$ 16	$ 7	$ 8	$ 5	$ 0	$ 45	$ 32	$ 9
Total	**$ 274**	**$ 114**	**$ 109**	**$ 49**	**$ 72**	**$ 80**	**$ 103**	**$ 36**	**$ 17**	**$ 426**	**$ 222**	**$ 207**

Each of the three cost components shown in Table 6.1 are discussed in greater detail below.

6.3.1 Minimum Load Cost Compensation

Pursuant to a FERC Order issued May 25, 2001,[6] and subsequent Orders, the CAISO provides minimum load cost compensation to generators that apply for waivers to the Must-Offer Obligation but are denied, and thus are required to be on-line at minimum load for the following operating day. In such cases, the CAISO compensates the generators for their minimum load costs, based upon unit operating costs and natural gas prices, where applicable. In addition, generators that are neither an RA or RCST resource[7] and whose waiver requests are denied are also entitled to receive the real-time price for energy supplied while operating at minimum load. Units subject to the Must-Offer Obligation are required to bid all unloaded capacity into the CAISO Real Time Market. In order to encourage units subject to must-offer to bid into the Ancillary Services Market, the CAISO filed Amendment 60, which enables them to keep ancillary services revenues without having to forfeit MLCC.

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[5] The figures representing real-time out-of-sequence redispatch costs in this chapter include some real-time dispatches that were not clearly identified as a direct consequence of real-time intra-zonal congestion management, but appear to have been related to the mitigation of intra-zonal congestion.

[6] 95 FERC 61,275; 95 FERC 61,418, etc. (2001).

[7] See Chapter 1 for a discussion of Resource Adequacy (RA) and Reliability Capacity Services Tariff (RCST).

Table 6.2 shows average must-offer and RA waiver denial capacity and total monthly costs in 2005 and 2006, as well as the imbalance energy payments that these generators received for their minimum-load energy based on real-time market prices. The costs shown in Table 6.2 also include MLCC costs for "system" reliability reasons in addition to intra-zonal reasons, which accounts for why these numbers are higher than the numbers shown in Table 6.1. The most notable trend in Table 6.2 is that the vast majority of the waiver denials and MLCC costs occurred during the first seven months of 2006. Of particular note are the high MLCC costs incurred in April 2006, which are attributed to the replacement of a key transmission line between the Lugo and Serrano substations. The decline in MLCC costs in the August-December 2006 time period can be attributed to the completion of the Lugo-Serrano upgrade, the Southwest Transmission Expansion Plan (which included upgrades to the Palo Verde-Devers and Hassayampa-North Gila-Imperial Valley 500kv series capacitors), and the installation of the Mountain View units, all of which have improved import capability from the Southwest. In addition, the end of the peak summer season reduced the need for zonal and system commitments.

Table 6.2 Must-Offer Waiver Denial Capacity and Costs ($MM)

	2005			2006		
Month	**Average MW***	**MLCC ($MM)**	**Imbalance ML Energy Payments ($MM)****	**Average MW***	**MLCC ($MM)**	**Imbalance ML Energy Payments ($MM)****
Jan	910	$ 8.3	$ 4.5	1065	$ 10.9	$ 4.0
Feb	823	$ 4.1	$ 1.5	965	$ 8.6	$ 2.8
Mar	770	$ 3.8	$ 1.5	1323	$ 11.6	$ 4.7
Apr	629	$ 5.9	$ 2.8	2444	$ 27.3	$ 13.7
May	1816	$ 14.3	$ 5.7	1331	$ 12.7	$ 6.8
Jun	1385	$ 7.5	$ 3.7	2478	$ 18.3	$ 2.9
Jul	1844	$ 21.8	$ 10.9	2150	$ 19.6	$ 7.1
Aug	1469	$ 18.0	$ 8.1	879	$ 4.9	$ 0.5
Sep	854	$ 8.6	$ 4.0	796	$ 2.8	$ 0.2
Oct	1236	$ 13.9	$ 6.0	309	$ 0.8	$ 0.0
Nov	1220	$ 12.2	$ 6.1	391	$ 1.1	$ 0.1
Dec	839	$ 11.5	$ 4.1	445	$ 2.1	$ 0.1
Annual Total	**1150**	**$ 130.1**	**$ 58.9**	**1215**	**$ 120.7**	**$ 42.8**

* Average maximum daily capacity of units on must-offer waiver. Includes minimum operating level plus unloaded capacity.

** Uninstructed energy payment for minimum load energy received by generator. Since MLCC covers full operating costs, this represents net operating revenue for the generator, or contribution to fixed costs.

Figure 6.2 compares MLCC payments to units that were denied waivers for intra-zonal or other local, zonal, and system reliability concerns, by reason, during 2005 and 2006. Figure 6.3 provides a breakdown of the 2006 figures by month.

The CAISO commits resources for system needs to protect against the risk of exhausting total power supply on the grid, particularly in summer months and days of unexpectedly high loads. As can be seen in Figure 6.2, system commitments decreased 36 percent to $11.5 million in 2006, from $18 million in 2005, due largely to higher levels of forward scheduling and self-commitment. MLCC costs for system needs in 2006 were mainly limited to the peak demand days in June and July.

SP26 zonal commitments increased to $25.9 million in 2006, a 32 percent increase from $17.7 million in 2005. These are commitments of Southern California resources to hedge against shortfalls within the SP26 zone. During peak summer periods, additional capacity is also committed within SP26 for contingencies. During the summer of 2005, there were large commitments across the control area and within SP15 in particular, for both system and South-of-Lugo reasons. Those unit commitments diminished the need to commit additional units for zonal reasons in 2005, as committed units can provide support for multiple constraints. Fewer commitments were made for local and system reasons during the peak summer months of June and July 2006, which reduced the amount of energy and unloaded capacity that contributed to maintaining reliability in SP15. As a result, the CAISO committed additional units in SP15 during this period to ensure reliability.

Other commitments are more local in nature and tend to be in response to local outages or for maintenance or transmission upgrades. MLCC costs associated with South-of-Lugo congestion declined 18.6 percent to $35 million in 2006 from $43 million in 2005. The decrease was due primarily to two factors: (1) the installation of the Mountain View generation facility in August 2005, which provides voltage support in the Los Angeles basin and increases the Lugo capacity rating, and (2) the replacement of the Lugo-Serrano 500kv line in April 2006 with lines connecting Lugo to Mira Loma, and Mira Loma to Serrano. This replacement resulted in congestion during the line work that caused the spike in Serrano-area MLCC costs in April, as seen prominently in Figure 6.3, but also resulted in significantly lower South-of-Lugo costs after it was completed. Other work in the area of the Serrano substation in northern Orange County occurred in late 2006.

Figure 6.2 MLCC Costs by Reason, 2005-2006

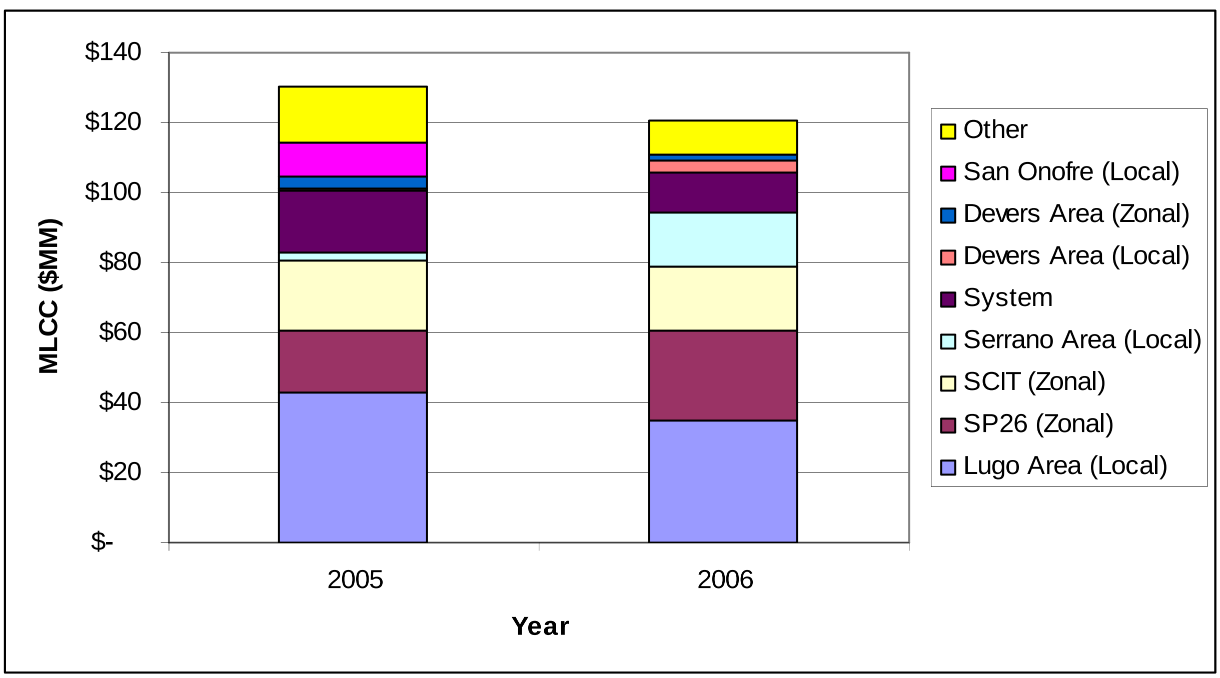


Figure 6.3 Monthly MLCC Costs by Reason, 2006

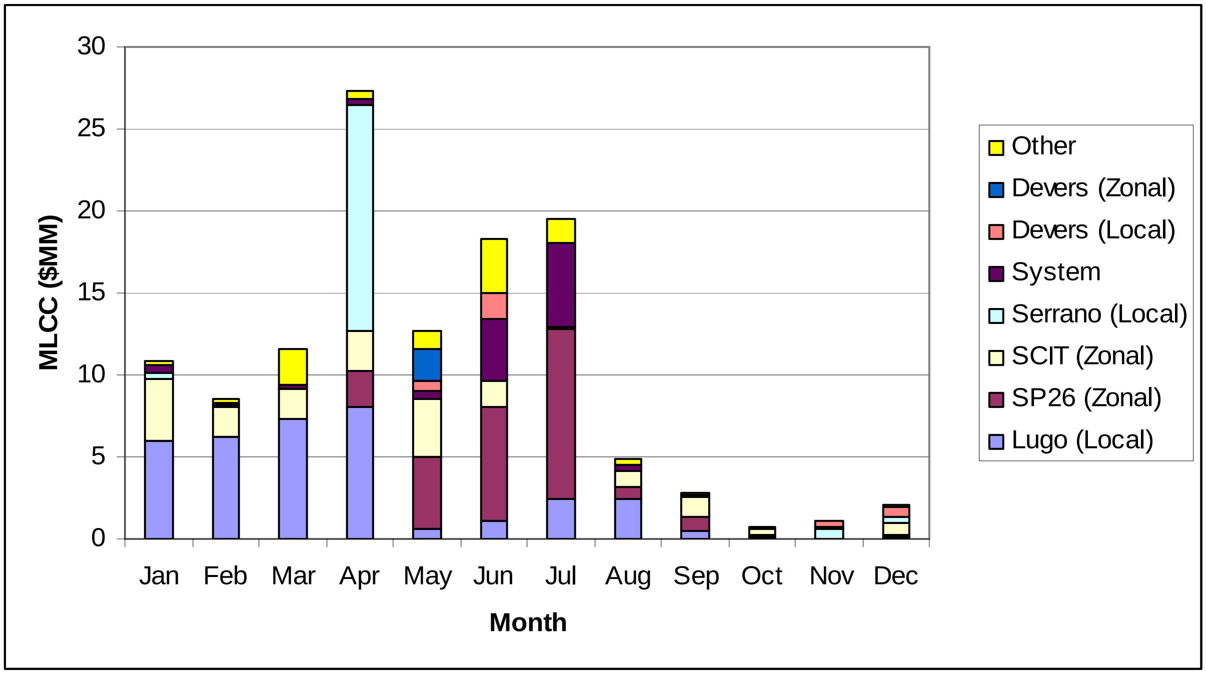


Figure 6.4 and Figure 6.5 show the average daily capacity commitments and average daily MLCC cost of waiver denials, respectively, by reason types (Local, Zonal, and System). The totals for all three reason type categories are the same as the values shown in Table 6.2. However, these figures provide additional detail on how the total average daily volume and costs break out across the three categories. Most notable in these figures is the significant increase in zonal (SP26) waiver denials and costs for the months of May through July, relative to 2005. The transmission upgrades and the installation of the Mountain View units reduced the need for local commitments within SP26, as previously noted, but resources were still needed to ensure zonal and system reliability. Additionally, the significant increase in local waiver denials and costs in April, as noted above, is due to the Serrano upgrade.

Figure 6.4 Average Daily Capacity on Must-Offer Waiver Denial for All Reasons (Local, Zonal, and System), 2005-2006

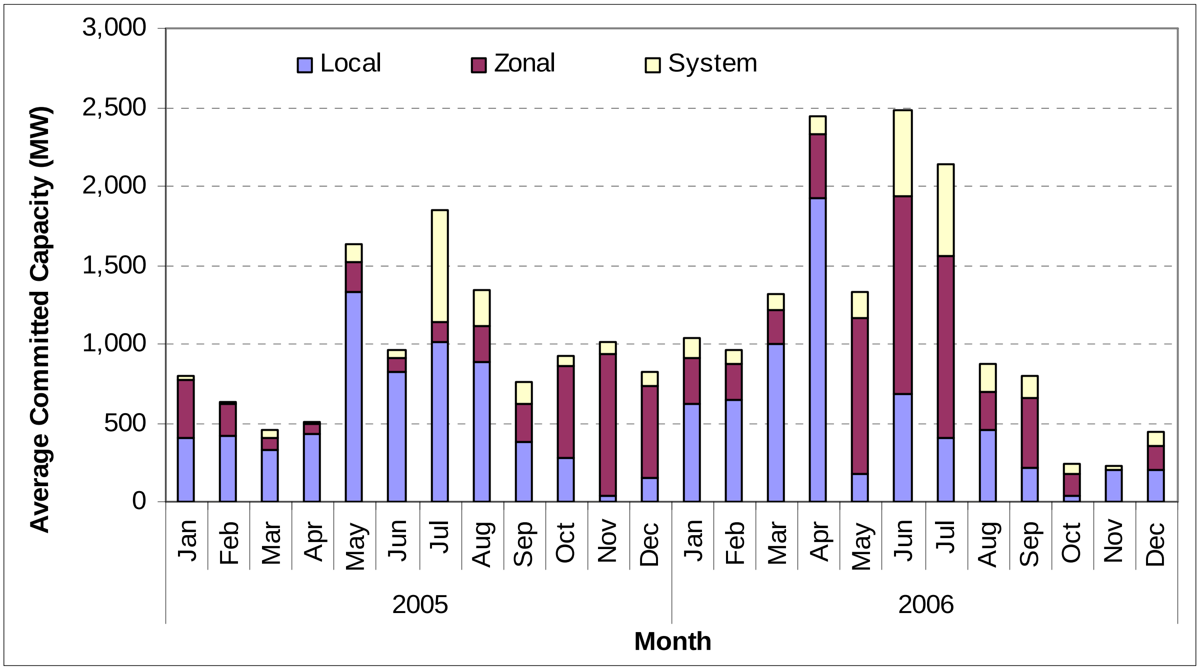
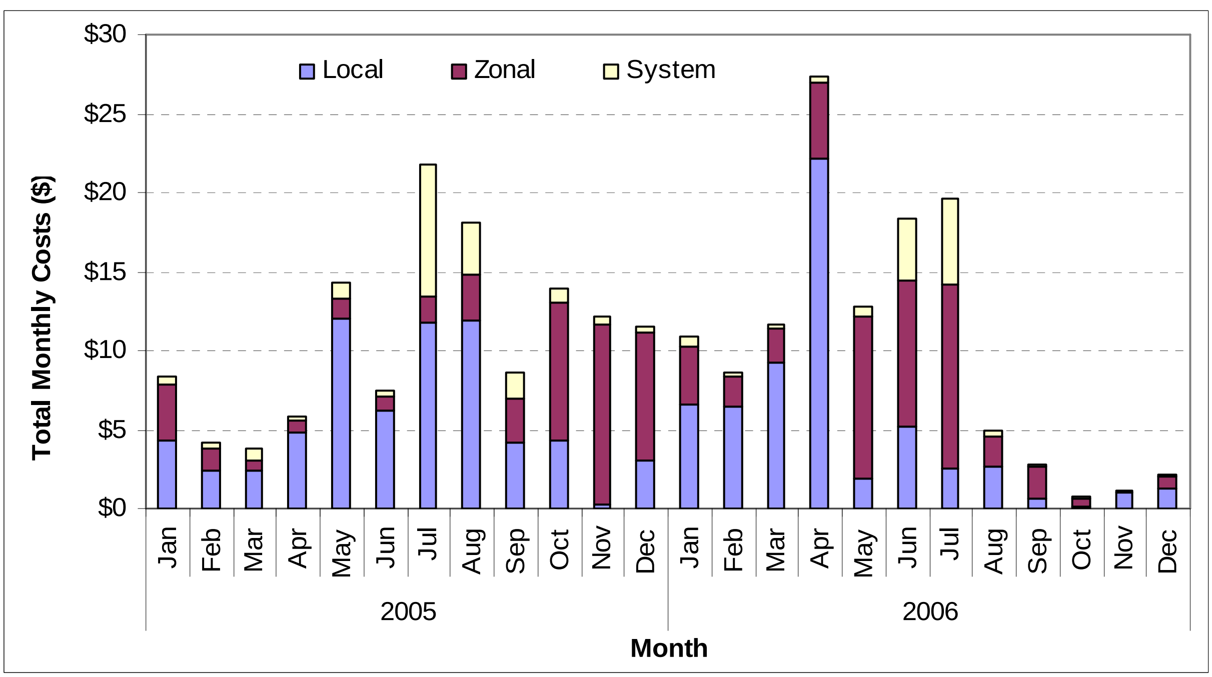


Figure 6.5 Total Monthly MLCC Payments for All Reasons (Local, Zonal, and System), 2005-2006

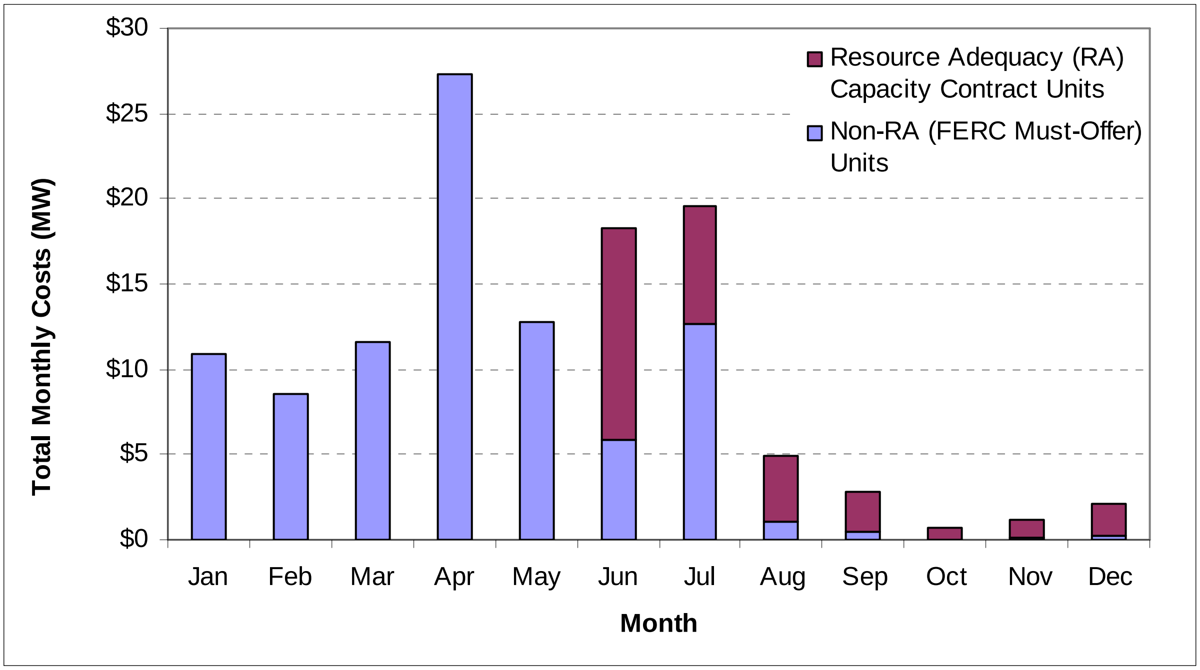


In 2006, resource adequacy (RA) programs developed by the CPUC and other Local Regulatory Authorities (LRAs) became effective. These programs require that load-serving entities (LSEs) procure sufficient resources to meet their peak load along with appropriate reserves. RA programs support system and local grid reliability by creating a framework intended to promote new generation investment in California by providing generation resources a revenue source to contribute towards fixed cost recovery. The CAISO facilitates implementation of these RA programs through its Interim Reliability Requirements Program (IRRP), which defines how RA resources are made available to the CAISO prior to the implementation of MRTU.

Beginning in June 2006, the CPUC directed its jurisdictional LSEs to procure sufficient resources to cover 100 percent of their forecasted load for each month, plus a 15 percent margin for operating and planning reserves. The California Energy Commission determined for each CPUC-jurisdictional LSE load forecast based on an allocation of each LSE's coincident share of the forecasted CAISO system peak for each month. Before applying the 15 percent reserve margin, each LSE's forecast load was adjusted downward based on its administratively determined share of demand response resources (i.e., load that can be curtailed) available in the utility service territory in which their load is located. LSEs not under CPUC jurisdiction, mainly local publicly-owned utilities, meet roughly similar requirements determined by their respective LRAs.

The implementation of the RA program in June 2006 has significantly reduced reliance on the FERC-directed Must-Offer Obligation. Since August 2006, the CAISO has been able to commit resources covered predominantly under RA contracts. However, in the months of June and July, a significant amount of non-RA capacity was denied waivers due to local and zonal needs in June and early July and system needs during the July heat wave. With the introduction of local resource adequacy requirements in 2007, the need for non-RA resources during the peak summer months should be further diminished. Figure 6.6 provides a monthly breakdown of minimum-load commitment costs by commitment type (RA or FERC Must-Offer).

Figure 6.6 Total Monthly MLCC Payments to Must-Offer vs. RA-Contracted Units in 2006



6.3.2 Reliability Must Run Costs

To mitigate local market power and to ensure that local reliability requirements are met, California's current market design relies upon RMR contracts with units located at known congested locations on the transmission grid. Through an annual planning process, the CAISO designates specific generating units as RMR units, based on the potential need for these units to be on-line and/or generate at sufficient levels to provide voltage support, adequate local generation in the event of system contingencies, and meet other system requirements related to local reliability. RMR contracts provide a mechanism for compensating unit owners for the costs of operating when units are needed for local reliability but may not be economical to operate based on overall energy and ancillary service market prices. RMR units are either pre-dispatched for local reliability needs (prior to real-time), or incremented in real-time either for local reliability or for intra-zonal congestion. RMR units cannot be pre-dispatched for intra-zonal congestion.

All RMR units receive two basic forms of compensation: (1) a Fixed Option Payment (FOP) that provides a contribution to each unit's fixed costs, and (2) a variable cost payment for energy provided under the RMR contract option, which is paid as the difference (if any) between the unit's variable operating costs and market revenues received for energy provided in response to an RMR requirement.[8]

Table 6.3 shows total fixed and variable RMR costs by month in 2006, and further divides variable cost payments into costs associated with pre-dispatched RMR energy for local reliability and additional real-time RMR energy dispatches for any remaining intra-zonal congestion.[9] Generators providing energy in response to a real-time RMR dispatch are paid based on their variable operating costs, with the responsible Transmission Owner (TO) receiving a credit back for the value of this energy at the real-time price. Thus, the net cost of real-time RMR dispatches for intra-zonal congestion or other local reliability requirements is equal to the difference between the RMR unit's variable operating cost and the real-time price of energy.

Table 6.3 Monthly RMR Contract Energy and Costs in 2006*

Month	Pre-Dispatched Energy (GWh)	Real-Time Energy (GWh)	Fixed Option Payments ($MM)	Net Pre-Dispatch Costs ($MM)	Net Real-Time Costs ($MM)	Total RMR Costs ($MM)
Jan	248	238	$ 25	$ 11	$ 13	$ 49
Feb	222	323	$ 19	$ 9	$ 15	$ 43
Mar	216	370	$ 21	$ 7	$ 13	$ 42
Apr	264	197	$ 21	$ 7	$ 8	$ 37
May	315	58	$ 22	$ 7	$ 3	$ 32
Jun	418	90	$ 25	$ 8	$ 4	$ 37
Jul	327	110	$ 26	$ 5	$ 2	$ 34
Aug	230	61	$ 23	$ 10	$ 3	$ 37
Sep	196	52	$ 22	$ 6	$ 2	$ 30
Oct	142	89	$ 20	$ 6	$ 3	$ 30
Nov	105	134	$ 17	$ 5	$ 6	$ 27
Dec	146	139	$ 18	$ 7	$ 7	$ 31
2006 Total	**2,830**	**1,861**	**$ 259**	**$ 88**	**$ 80**	**$ 428**
% ∆ from 2005	-47.8%	21.8%	2.7%	-51.7%	10.9%	-15.7%

* Dispatch quantities and costs reported in Table 6.3 only include dispatches under the "Contract Option."

Total RMR costs continued to decrease in 2006 to approximately $428 million, from approximately $505 million in 2005.[10] This continued the trend between 2004 and 2005. The decrease in costs may be due to a combination of factors; namely:

- The portion of RMR unit capacity selecting Condition 2 (non-market) of the pro forma RMR contract continued to decrease, resulting in lower variable cost payments. RMR-providing generation owners may select either Condition 1 or 2. Condition 1 entitles the

8 Units under Condition 1 of the RMR contract are free to select the "Market Option" when receiving an RMR dispatch on a day-ahead or hour-ahead basis, in which case they keep all revenues from sales of this energy and do not receive any reimbursement for variable operating costs.

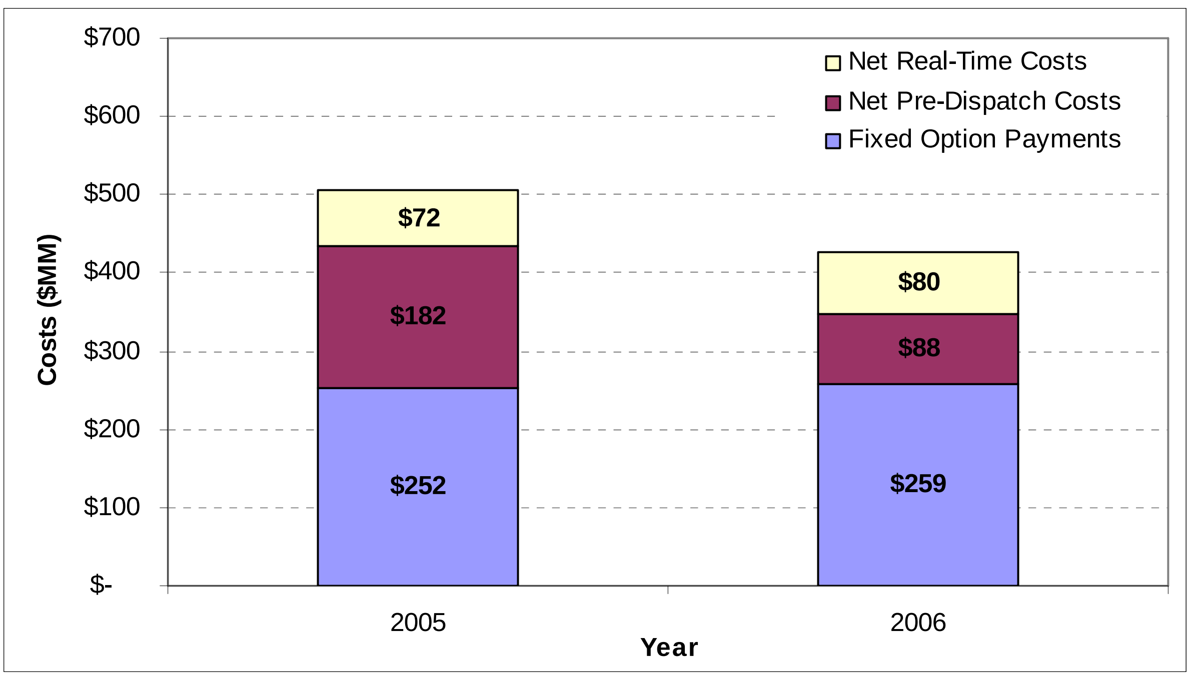
9 Since selection of RMR units and pre-dispatch of RMR units is based on local reliability requirements, these costs are not specifically associated with intra-zonal congestion. While annual designation of RMR units and pre-dispatch of RMR units to meet local area reliability requirements may reduce intra-zonal congestion in real-time, these costs would be incurred even if intra-zonal congestion did not occur in real-time. Thus, it is more appropriate to exclude costs associated with the FOP and pre-dispatch of RMR units from intra-zonal congestion costs.

10 In last year's report, total RMR costs of $460 million were reported in 2005. However, this estimate was based on preliminary settlement information for November and December 2005. The $505 million estimate for 2005 reflects final settlement data for those months as well as other settlement corrections, which in total, amount to an increase of $45 million over last year's reported estimate. A similar issue may occur next year with regard to the reported RMR costs for 2006.

generation owner to participate in the market, and, if dispatched for RMR, to select on a daily basis whether to collect variable contract-based rates (Contract Path) or market revenues (Market Path). Because Condition 1 units have market opportunities, they receive a lower monthly FOP.[11] Condition 2 effectively is a tolling agreement between the CAISO and the generation owner, where the owner receives a higher FOP, but receives cost-based payments for its energy and cannot participate in the market unless given an RMR dispatch. The higher proportion of owners electing Condition 1 is indicative of improved market conditions for energy sales in bilateral and real-time markets. Several RMR-contracted resources have also been sold by traditional merchant energy companies to investor, private equity, and investment bank-backed organizations. Condition 2 unit capacity accounted for approximately 11.8 percent of total RMR-contracted unit capacity by the end of 2006, compared to 19.6 percent at the end of 2005.

- Due to greater installed generation and transmission, RMR dispatch requirements decreased. Total RMR dispatch volumes, including both contract and market path dispatches, decreased to 6,349 GWh in 2006, compared to 9,454 GWh in 2005, and approximately 15,000 GWh in 2004. Variable contract-path costs totaled $168 million in 2006, compared to approximately $254 million in 2005.

Figure 6.7 Total RMR Costs, 2005-2006



[11] RMR Condition 1 revenues from dispatch under the Market Path are not included in the calculation of reliability costs, but are included as real-time market costs in the calculation of total wholesale market costs in Chapter 2.

Figure 6.8 RMR Capacity by Resource and Contract Type, 2004-2006

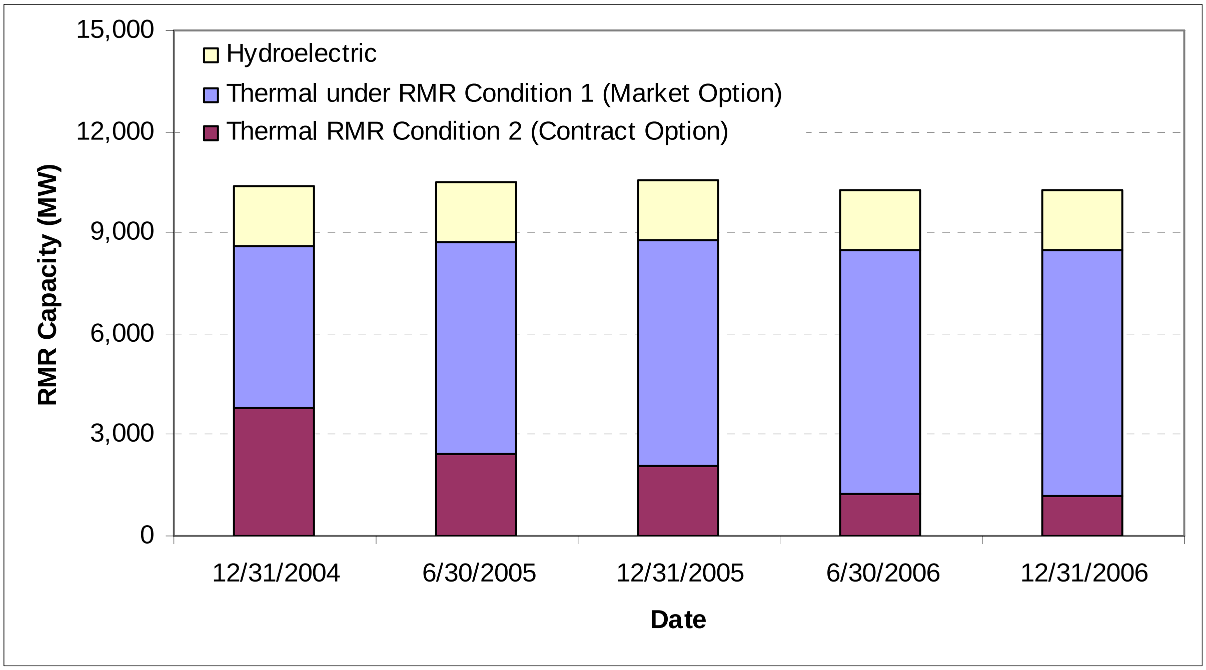
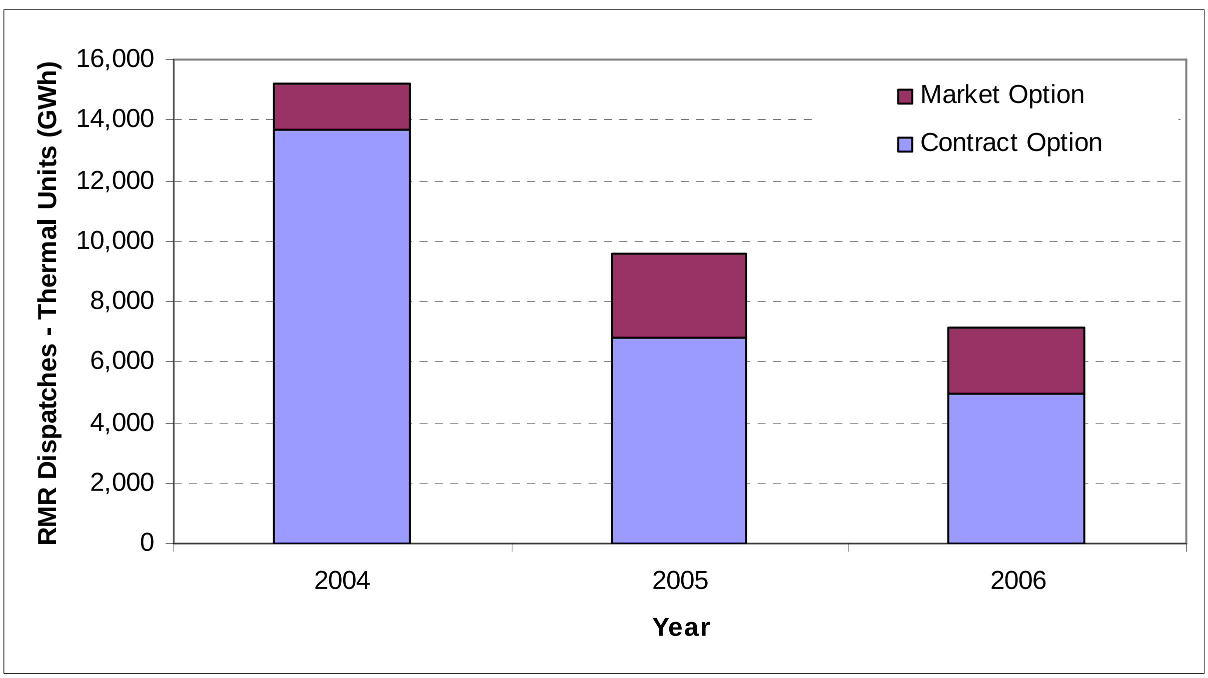


Figure 6.9 RMR Dispatch Volumes – Thermal Units (2004-2006)



6.3.3 Out-of-Sequence (OOS) Costs

The costs of Out-Of-Sequence (OOS) dispatches for mitigating real-time intra-zonal congestion is measured in terms of the redispatch cost, which is the incremental cost incurred from having to dispatch some resources up and other resources down to alleviate the congestion. For incremental energy bids dispatched OOS, the redispatch cost is the difference between the price paid to the resource for OOS energy (generally, their bid price) less the market clearing price (the cost of balancing the OOS energy). For decremental energy bids dispatched OOS, the redispatch cost is based on the market clearing price for incremental energy less the reference price for decremental OOS energy.[12]

As shown in Table 6.4, net redispatch costs of incremental dispatches to load-serving entities, or the costs in excess of real-time market prices, was approximately $4.3 million in 2006, compared to $3.3 million in 2005. In all, the CAISO procured 127 GWh of incremental OOS energy at an average price of $68.89/MWh, or $33.70/MWh above market.

Table 6.5 shows decremental OOS statistics. Decremental redispatch costs, or the amount of money below the market price that resources save when the CAISO reduces their output in order to avoid intra-zonal congestion, totaled $13.2 million in 2006, compared to $31.3 million in 2005. In all, the CAISO decremented 783.8 GWh of OOS energy in 2006 at an average price of $36.11/MWh, or $16.83/MWh below market.

The decline in total costs was largely attributable to upgrades at the Miguel and Pastoria/Magunden areas. These congestion points were very problematic in 2005, and transmission work has resulted in significantly lower costs.

Table 6.4 Incremental OOS Congestion Costs in 2006

	GWh	Gross Cost ($MM)	Redispatch Premium ($ MM)	Mitigation Savings ($)	Average Price	Average Net Cost ($/MWh)
Jan	4.0	$ 0.3	$ 0.2	$ 16,197	$ 78.93	$ 49.04
Feb	2.8	$ 0.2	$ 0.1	$ 2,204	$ 73.40	$ 32.53
Mar	5.6	$ 0.5	$ 0.3	$ 48,145	$ 81.14	$ 55.03
Apr	49.1	$ 3.5	$ 2.1	$ 33,035	$ 71.55	$ 41.98
May	16.9	$ 1.1	$ 0.5	$ -	$ 66.42	$ 30.29
Jun	12.4	$ 0.8	$ 0.3	$ 313	$ 66.13	$ 26.90
Jul	18.6	$ 1.3	$ 0.4	$ 18,727	$ 69.07	$ 20.16
Aug	1.3	$ 0.1	$ 0.0	$ -	$ 74.72	$ 16.53
Sep	2.5	$ 0.2	$ 0.2	$ -	$ 95.21	$ 62.72
Oct	0.3	$ 0.0	$ 0.0	$ -	$ 40.40	$ 11.75
Nov	5.2	$ 0.3	$ 0.1	$ 1	$ 52.29	$ 15.18
Dec	8.3	$ 0.4	$ 0.1	$ 5,572	$ 50.00	$ 17.16
2006 Total	**127.0**	**$ 8.7**	**$ 4.3**	**$ 124,193**	**$ 68.89**	**$ 33.70**

[12] This discussion excludes OOS and OOM dispatches for system conditions, which totaled approximately $6.5 million in redispatch costs in 2006. These dispatches were largely incremental dispatches to RMR Condition 2 units during the summer heat wave, which under the RMR contract are not required to bid, and decremental dispatches to pump storage units to offset over-generation during the spring months.

Table 6.5 Decremental OOS Congestion Costs in 2006

	GWh	Gross Cost ($MM)	Redispatch Premium ($ MM)	Average Price	Average Net Cost ($/MWh)
Jan	(154.1)	$ (5.3)	$ 3.5	$ 34.51	$ 22.46
Feb	(105.0)	$ (2.7)	$ 1.7	$ 25.54	$ 16.40
Mar	(150.5)	$ (4.9)	$ 2.3	$ 32.32	$ 15.61
Apr	(142.5)	$ (4.6)	$ 3.7	$ 32.06	$ 26.06
May	(4.8)	$ (0.1)	$ 0.1	$ 27.76	$ 20.45
Jun	(6.0)	$ (0.2)	$ 0.2	$ 27.82	$ 25.60
Jul	(2.1)	$ (0.1)	$ 0.1	$ 41.87	$ 32.08
Aug	(10.1)	$ (0.4)	$ 0.3	$ 35.71	$ 34.57
Sep	(24.5)	$ (1.0)	$ 0.1	$ 38.76	$ 4.75
Oct	(88.8)	$ (4.1)	$ 0.6	$ 46.30	$ 6.80
Nov	(35.0)	$ (1.9)	$ 0.3	$ 55.20	$ 7.39
Dec	(60.4)	$ (3.1)	$ 0.3	$ 51.80	$ 5.01
2006 Total	**(783.8)**	**$ (28.3)**	**$ 13.2**	**$ 36.11**	**$ (16.83)**

Figure 6.10 shows annual redispatch costs by reason in 2006. Figure 6.11 provides a similar breakdown on a monthly basis. As evident in Figure 6.11, intra-zonal congestion costs were most significant during the first part of the year (January-April) and declined significantly for the rest of the year. Congestion at the Pastoria/Magunden substations and the South-of-Lugo area were particularly costly between January and April, totaling approximately $8.5 million in redispatch costs in those months. The Big Creek Project and the Pastoria generation facility respectively are key sources of generation connected to the Southern California grid. Together, they represent approximately 1,770 MW of generation capability, and provide important flexibility to the import-constrained SP26 region. With the completion in mid-2006 of upgrades to the Pastoria-Pardee, Pastoria-Baily-Pardee, and Pastoria-Warner-Pardee 230kv lines, and the installation of two new 230kv Magunden-Antelope lines, congestion costs at the Magunden/Pastoria transmission facilities were nearly eliminated. Beginning in May 2006 through the end of the year, South of Pastoria/Magunden congestion costs were limited to $547,000. South-of-Lugo congestion is primarily due to power from Hoover Dam and other generation facilities in the Southwest, as well as from the High Desert and Cool Water combined-cycle facilities, which pass through the Lugo Substation. South-of-Lugo congestion costs were particularly significant in April 2006, totaling $2 million in that month alone. This increase was again due to the rerouting of the Lugo-Serrano line through the Mira Loma substation. As a consequence of this upgrade, South-of-Lugo congestion was minimal after April.

Figure 6.10 Intra-Zonal OOS/OOM Redispatch Costs by Reason in 2006

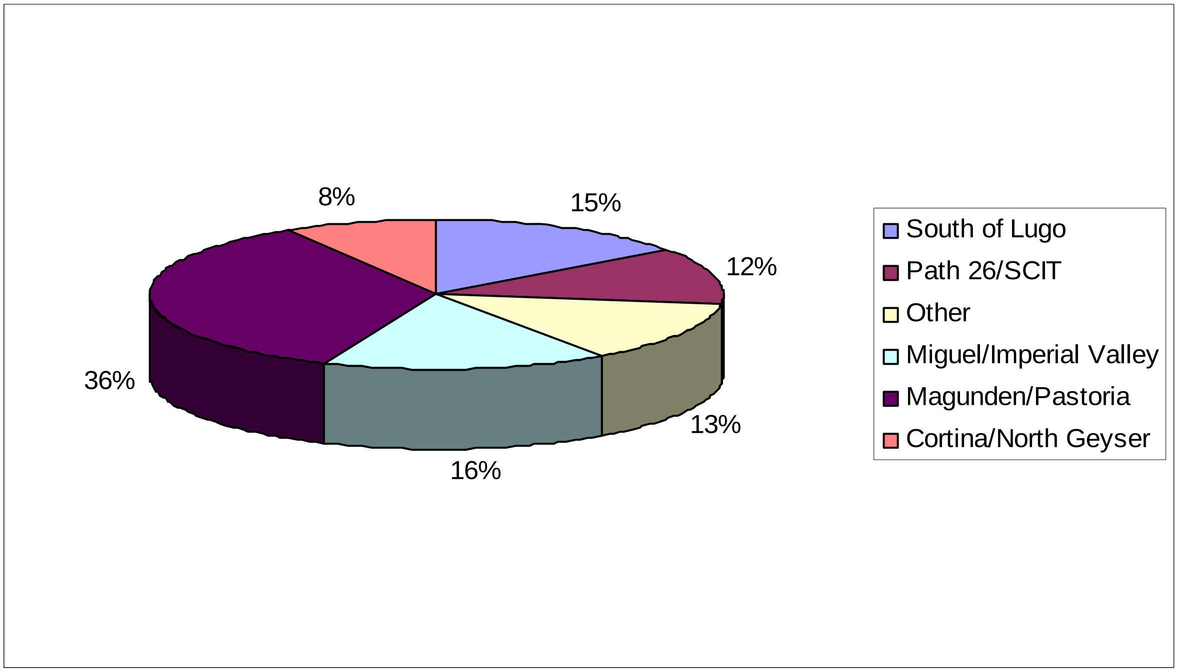
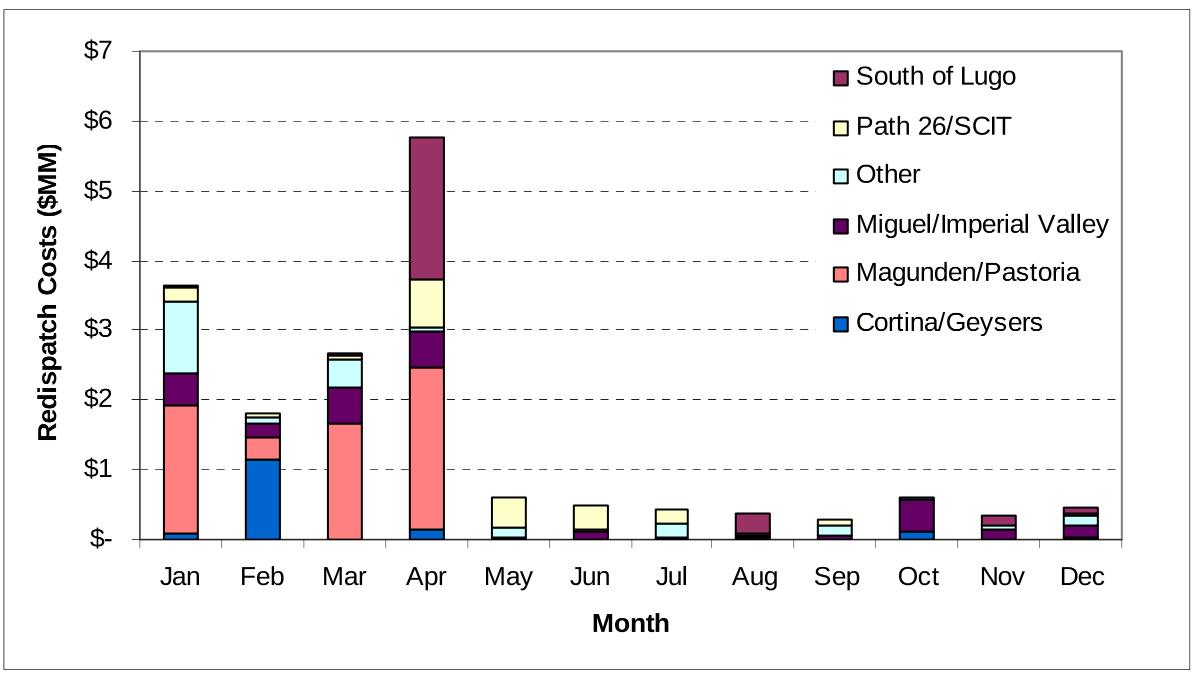


Figure 6.11 Monthly Contribution to Intra-Zonal Congestion OOS Redispatch Costs by Reason in 2006



Intra-zonal congestion at the Miguel substation, which had been a major bottleneck in prior years, was largely eliminated in 2006 due to transmission upgrades in that region in mid-2005.

Congestion in the Miguel-Imperial Valley area decreased to $2.8 million in 2006 from $10.1 million in 2005. Most of this congestion occurred between January and April, due to outages for the short-term STEP upgrades. One Bay Area location in particular incurred substantial intra-zonal congestion costs in 2006. The bulk of these costs were due to transmission upgrades for the Cortina substation and the Geysers generation facilities, particularly in February. The derates of the Cortina substation for the upgrade necessitated out-of-sequence decremental dispatches of the Geysers area facilities.

The Southern California Import Transmission (SCIT) Nomogram, a constraint on the quantity of energy that can be imported into Southern California at any moment, was binding less frequently in 2006 than in the past. Pursuant to Operating Procedure T-103,[13] SCIT can be mitigated either by intra-zonal congestion management through out-of-sequence redispatch or by splitting the NP15 and SP26 markets, as deemed necessary by operators given conditions on the grid. SCIT and SP26 import intra-zonal congestion costs were approximately $2.1 million in 2006, compared to $1.1 million in 2005.[14]

[13] http://www.caiso.com/docs/2002/01/29/2002012909363927693.pdf

[14] The costs of the various reasons for SP26 intra-zonal congestion are not explicitly separable.

7 Market Surveillance Committee

7.1 Market Surveillance Committee

Historically, the Market Surveillance Committee (MSC or Committee) has served as an impartial voice on market issues primarily for the CAISO as well as for state policymakers, the FERC and the media. CAISO management and the FERC have adopted a number of Committee recommendations since its inception. The MSC has been recognized consistently by the industry and the public as useful and effective, due in large part to the stature of its members as nationally recognized experts as well as their perceived independence. Both characteristics have led to the MSC being shown considerable deference by state and federal regulators.

7.1.1 Current Members

In 2006, the Committee was comprised of the following members: Frank Wolak of Stanford University, Benjamin Hobbs of Johns Hopkins University and James Bushnell of the University of California Energy Institute at Berkeley. Frank Wolak served as the chairman of the Committee.[1] The following is a brief description of each member's background.

Dr. Frank A. Wolak, the chairman of the MSC since its inception in 1998, is a Professor of Economics at Stanford University. His fields of research are industrial organization, regulatory economics, energy economics and econometric theory. He specializes in the study of methods for introducing competition into infrastructure industries – telecommunications, electricity, water delivery and postal delivery services – and on assessing the impacts of these competition policies on consumer and producer welfare. Dr. Wolak is a visiting scholar at the University of California Energy Institute and a Research Associate of the National Bureau of Economic Research (NBER). Dr. Wolak has a Ph.D. in Economics from Harvard University, a B.A. in Economics from Rice University, a M.A. in Economics from University of New Mexico and a S.M. in Applied Mathematics from Harvard University.

Dr. Benjamin F. Hobbs, a member of the MSC since 2002, is a Professor of Geography & Environmental Engineering and Applied Mathematics & Statistics in the Whiting School of Engineering, at Johns Hopkins University since 1995. He is a former Professor of Systems Engineering and Civil Engineering at Case Western Reserve University. He has previously held positions at Brookhaven National Laboratory and Oak Ridge National Laboratory. He is presently Scientific Advisor to The Energy Research Centre of the Netherlands and a member of the Public Interest Advisory Committee for the Gas Technology Institute. His research interests include stochastic electric power planning models, environmental and energy systems analysis and economics, multi-objective and risk analysis, ecosystem management, and mathematical programming models of imperfect energy markets. Dr. Hobbs is published in numerous journal articles and magazine articles and has co-authored two books. Dr. Hobbs has a Ph.D. in Environmental Systems Engineering from Cornell University.

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[1] More information is available at http://www.caiso.com.

Dr. James Bushnell, a member of the MSC since 2002, has served as a Research Scientist for over ten years at the University of California Energy Institute, Berkeley, California, and currently serves as the Research Director of the California Energy Institute at Berkeley. He also serves as Lecturer at the Haas School of Business, UC Berkeley, on Policies and Strategies in the Energy Markets. He is a former member of the Market Monitoring Committee of the California Power Exchange (CALPX). His research interests include game theoretic optimization models, industrial organization and regulatory economics, energy policy, and environmental economics. He has published numerous articles on the economics of electricity deregulation and has testified extensively on energy policy issues. Much of his research has focused on examining the market incentives in particular; market rules and structures created; and in developing empirical methods for measuring the impact of market power on deregulated electricity markets. Dr. Bushnell has a Ph.D. in Industrial Engineering and Operations Research with a B.S. in Economics and Industrial Engineering.

7.1.2 Accomplishments

During 2006, the MSC provided valuable input and recommendations to various issues relating to the operation of the current CAISO markets and the Market Redesign and Technology Upgrade (MRTU) proposals. Some of their more significant contributions include the following:

- **Convergence Bidding under MRTU –** The topic of convergence or "virtual" bidding under MRTU was presented and discussed at several MSC meetings in 2006. Though the initial release of MRTU will not include convergence bidding, the CAISO is working diligently to develop and implement a convergence bidding design shortly after the first release of MRTU. The MSC has provided valuable input on various aspects of convergence bidding such as the spatial granularity of convergence bidding and market power mitigation and monitoring requirements. The MSC will continue to contribute to this topic as the CAISO moves toward finalizing a convergence bidding design in 2007.

- **Long-term Congestion Revenue Rights –** Pursuant to a FERC Ruling in July 2006, the CAISO developed and filed on January 29, 2007 a proposal for long-term congestion revenue rights under MRTU. The filed proposal was the product of an extensive stakeholder effort in the fall of 2006, which the MSC was very engaged in. Through stakeholder and MSC meetings, the MSC members provided comments and recommendations on the long-term CRR design. These recommendations were formalized in an MSC Opinion on January 18, 2007.[2]

- **Capacity Markets –** The issue of whether the California market needs a centralized capacity market and, if so, how that market should be designed was an important topic of discussion among California market participants and the California Public Utilities Commission (CPUC) in 2006. This issue was discussed at several MSC Meetings, including an extensive discussion at the CPUC headquarters in San Francisco in which the MSC heard from several groups representing different positions on this issue.

- **Low Voltage Transmission Costs –** In 2006, the MSC provided recommendations to the CAISO on certain principles they should follow in determining how to allocate the

[2] This opinion is available at http://www.caiso.com/docs/2000/09/14/200009141610025714.html.

cost of low voltage transmission facilities. This issue arose with regard to a particular low voltage transmission project, the Trans Bay Cable project, that was approved by the CAISO Board on September 8, 2005 to address reliability concerns in the San Francisco peninsula region.

- **Transmission for Renewable Generation –** On January 25, 2007, the CAISO filed with the FERC a proposal for an alternative approach for generation interconnection and transmission cost allocation that, if adopted, would reduce barriers to the development of renewable generation. This proposal is currently pending before the Commission. In developing this proposal, the CAISO sought and obtained significant input from the MSC, including an MSC Opinion that was adopted on October 6, 2006.[3] MSC members also provided guidance on appropriate economic frameworks and techniques to evaluate proposed transmission for renewables.

- **Designation of Competitive Paths –** MSC members provided advice to the CAISO on procedures for identifying competitive paths for the purposes of local market power mitigation.

7.1.3 MSC Meetings

In 2006, the MSC conducted five meetings and two teleconferences. The majority were held at the CAISO offices in Folsom, and one was held at the CPUC headquarters in San Francisco in August 2006,. The meetings provided a forum for stakeholders to take part in discussions with the MSC and allowed the MSC to understand the opinions and concerns of the stakeholders.

7.1.4 Other MSC Activities

In addition to the activities and accomplishments noted above, members of the Committee also attended FERC Technical Conferences throughout the year on MRTU market design. They also attended a FERC meeting with market monitors from the various ISOs/RTOs and the FERC Office of Enforcement to discuss generic market monitoring and enforcement issues.

[3] This opinion is available at http://www.caiso.com/docs/2000/09/14/200009141610025714.html.