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

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[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

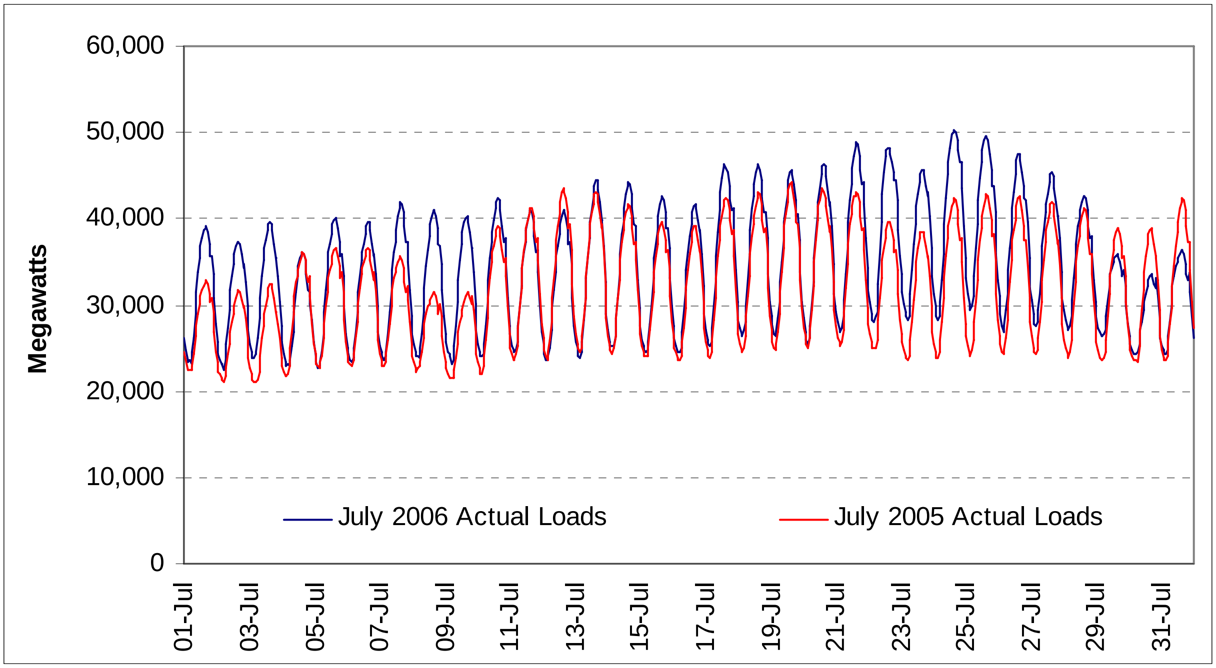


Figure 2.2 depicts load duration curves for each of the last five years and demonstrates the significant increase in load during 2006. Most striking in 2006 is the percentage of hours that load exceeded 40,000 MW, which used to be considered an extreme peak level. In 2006, hourly loads exceeded 40,000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

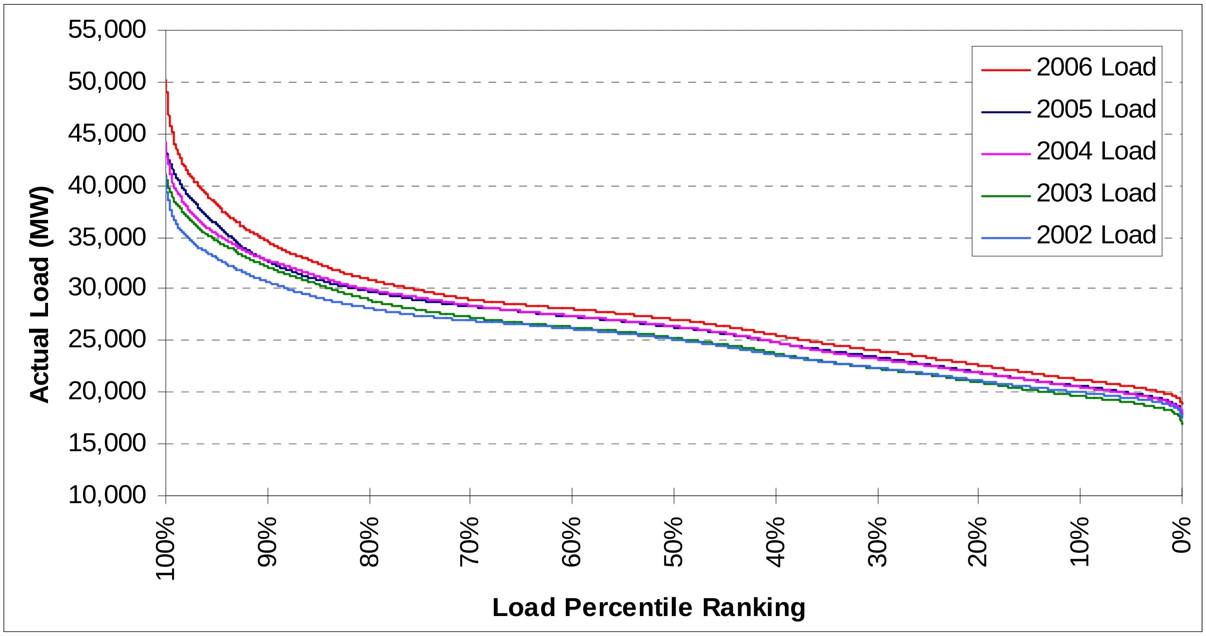


Table 2.3 shows yearly average load changes in NP26 and SP15, and for the CAISO Control Area as a whole. The NP26 all-time peak of 22,650 MW, set July 24, 2006 greatly exceeded the previous year's normalized peak of 19,934 MW, an increase of 13.6 percent. The SP15 all-time peak of 27,682 MW, also set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

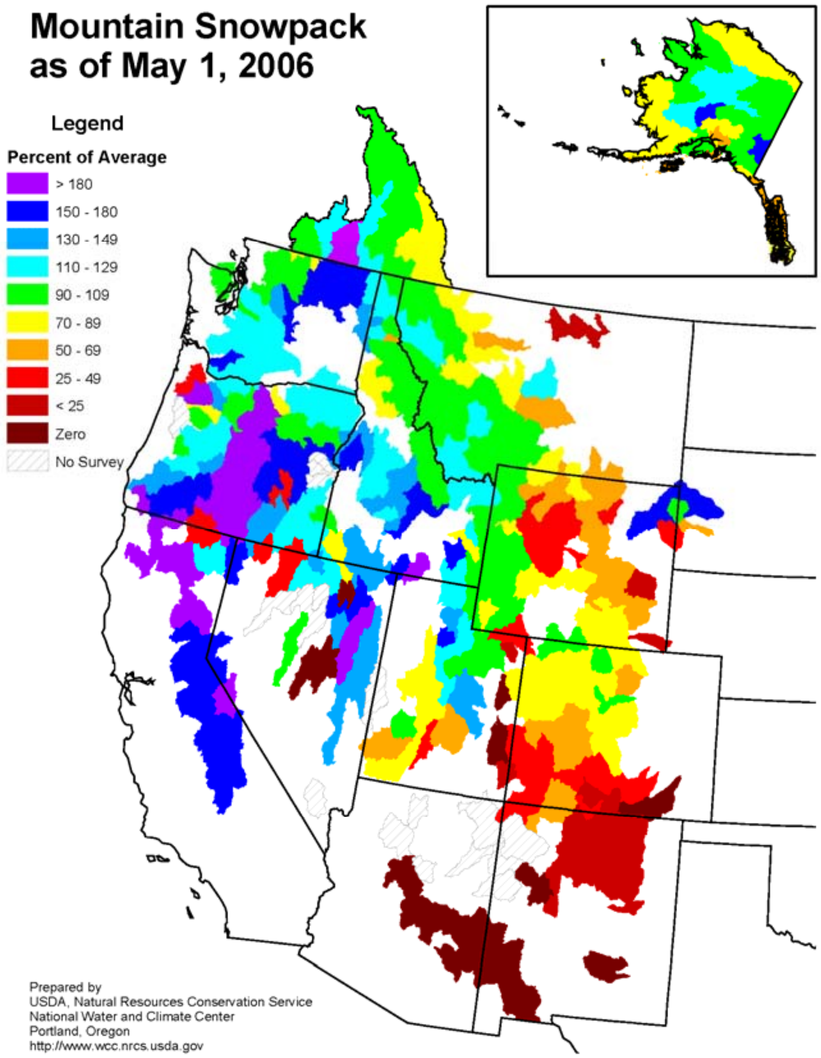
	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-06	3.7%	3.2%	3.6%	0.1%
February-06	3.0%	3.1%	3.4%	3.1%
March-06	4.3%	4.3%	7.6%	3.0%
April-06	-0.5%	-0.5%	1.1%	-0.9%
May-06	1.2%	0.6%	2.1%	1.2%
June-06	13.0%	18.1%	5.7%	23.8%
July-06	10.7%	11.8%	8.9%	4.6%
August-06	0.2%	-0.7%	1.8%	-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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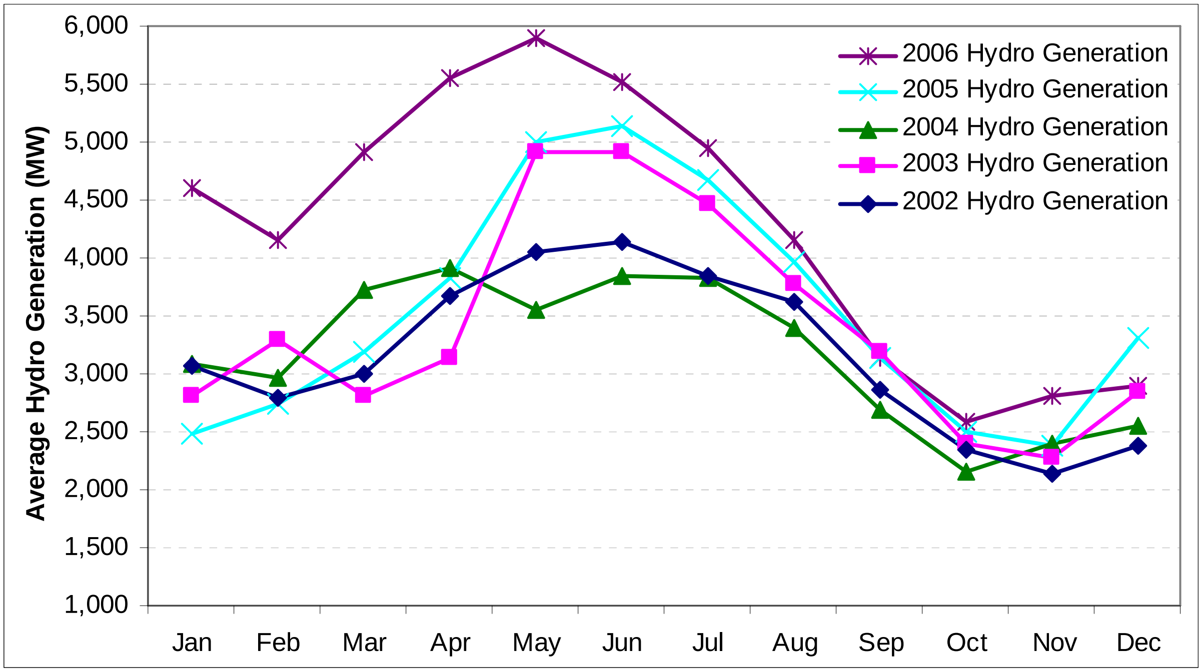
Given the robust snowpack within California, hydroelectric production exceeded the recent five-year range for the majority of 2006 (Figure 2.4). This was particularly true during the first half of 2006 with average hydro production in January through April between 40 and 60 percent greater than the previous 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.

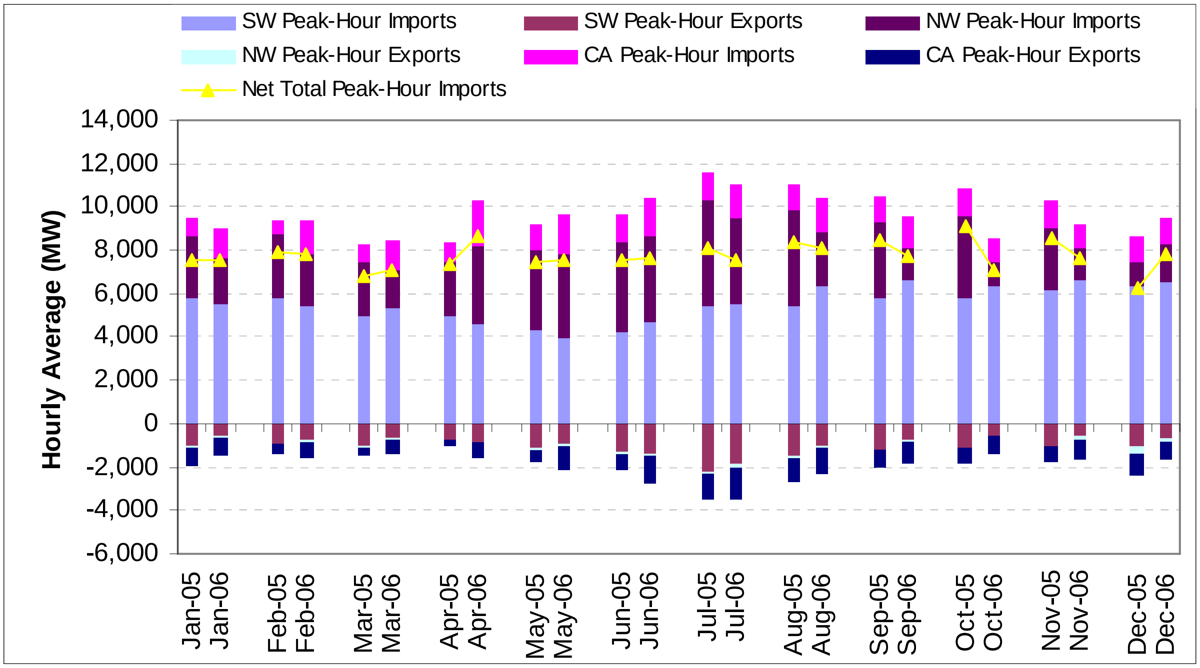
Figure 2.4 Monthly Average Hydroelectric Production: 2002-2006



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.

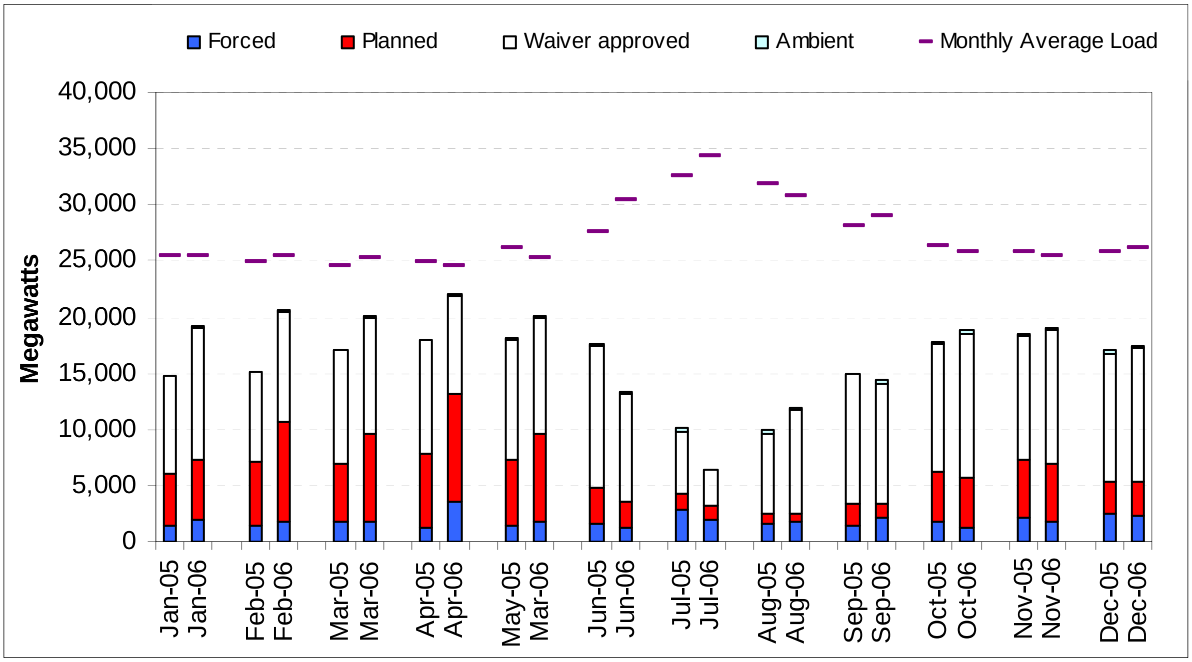
Figure 2.5 Year-to-Year Comparison of Monthly Average Scheduled Imports and Exports: 2006 vs. 2005



2.2.3 Generation Outages

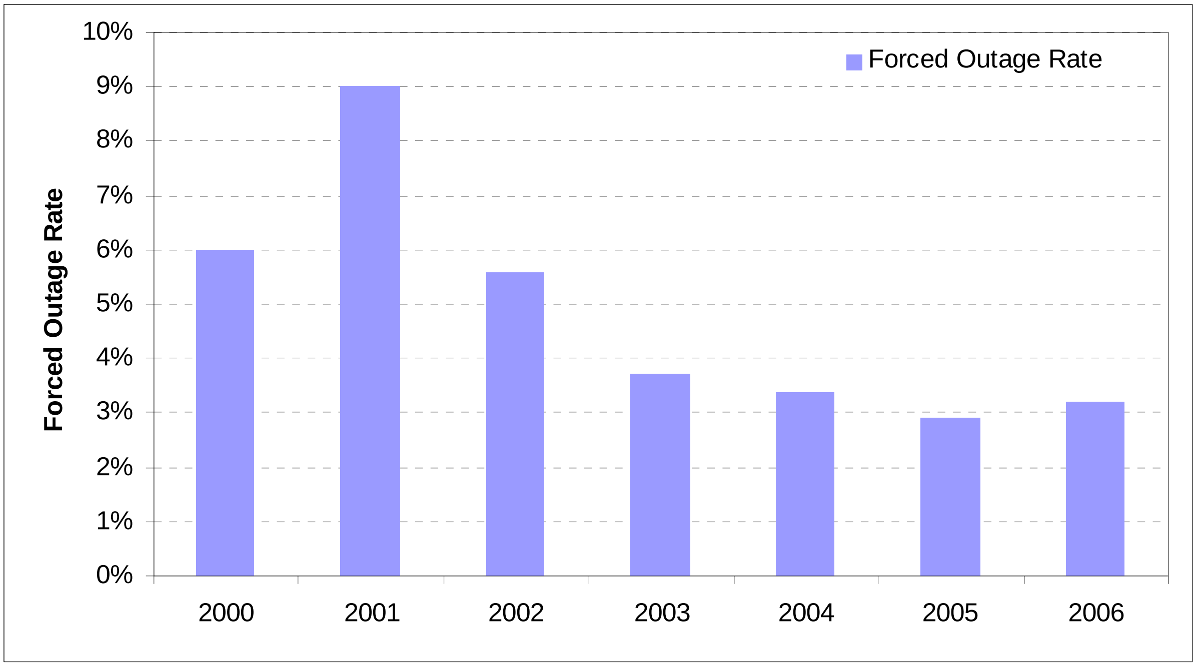
During the aforementioned July heat wave, the CAISO Control Area's entire generation fleet was operating seven days a week. For the entire duration of the peak of the heat wave, which lasted from July 17 to July 28, CAISO loads exceeded 45,000 MW on every day, even during the weekends. Peak loads were 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]

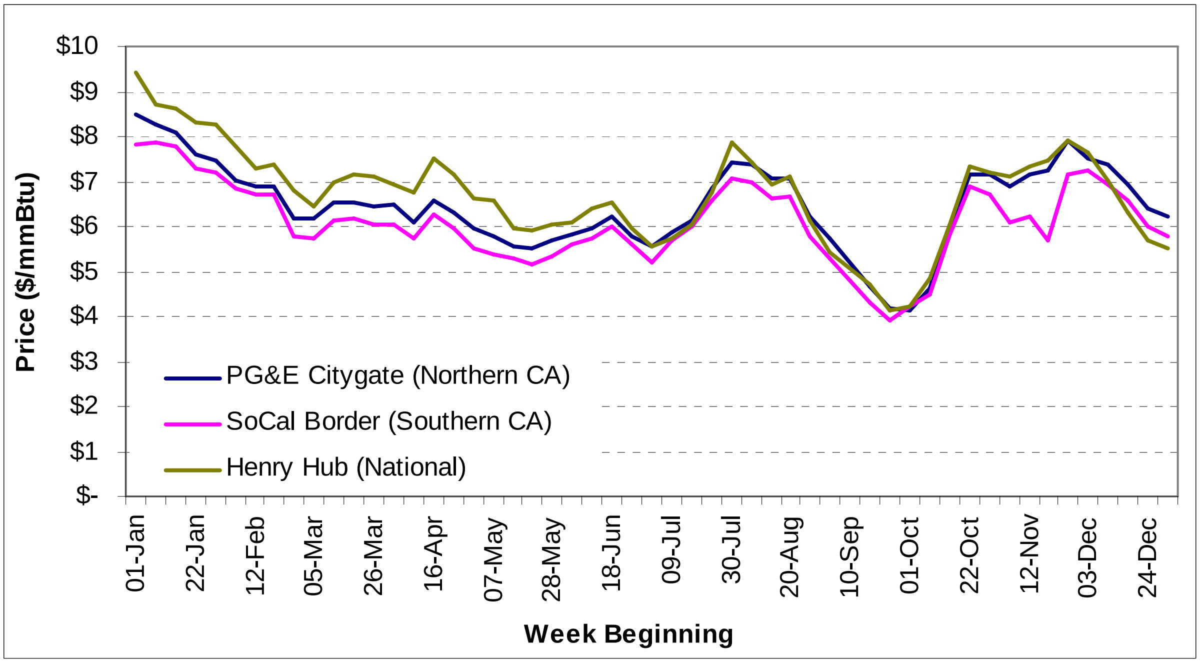


2.2.4 Natural Gas Prices

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

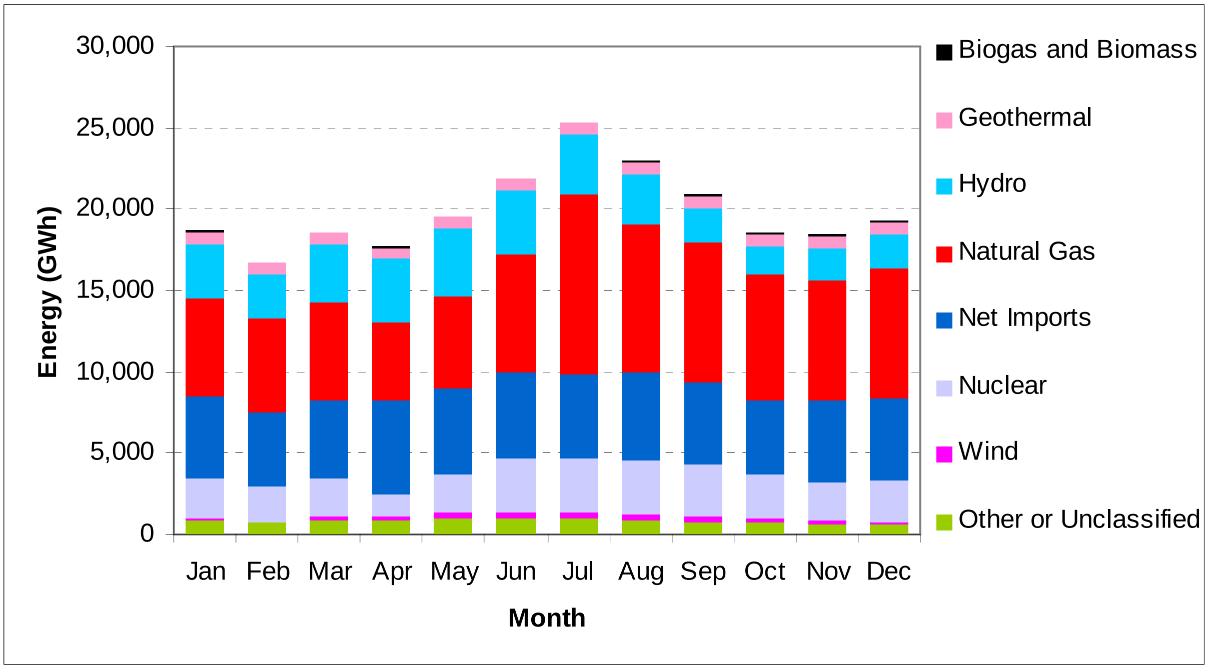


2.2.5 Generation by Fuel Source

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

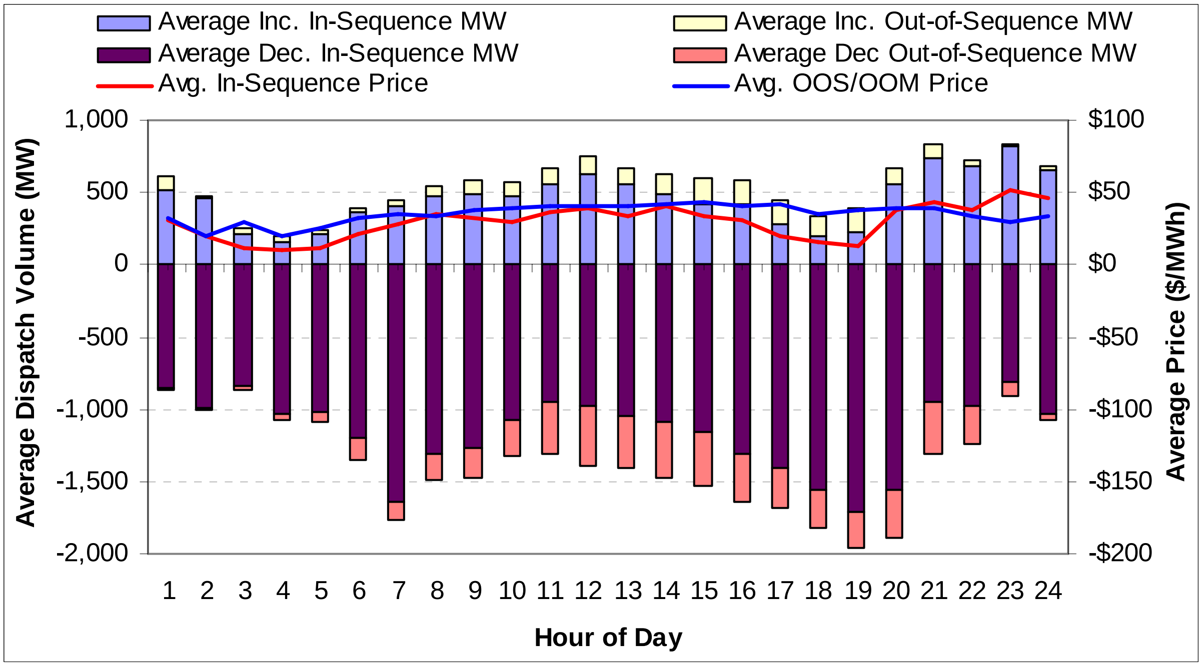
2.3.1 Spring Hydro Runoff

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.

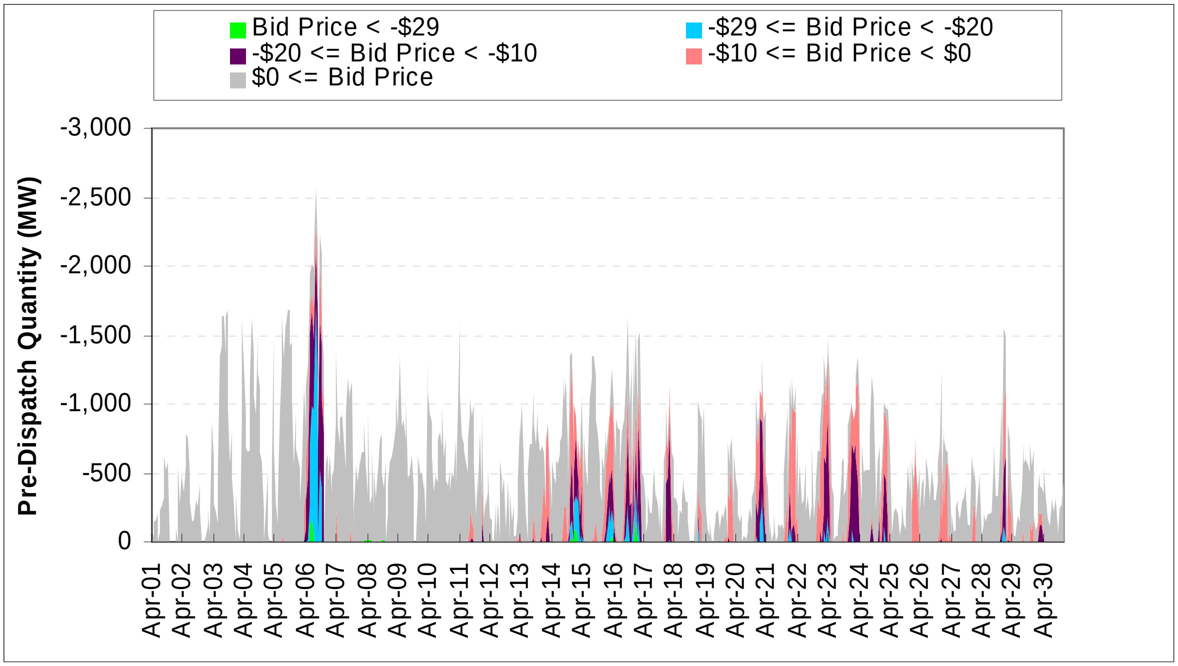
Figure 2.10 Hourly Profile of ISO Average Incremental and Decremental Dispatch and Price, April 2006



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.

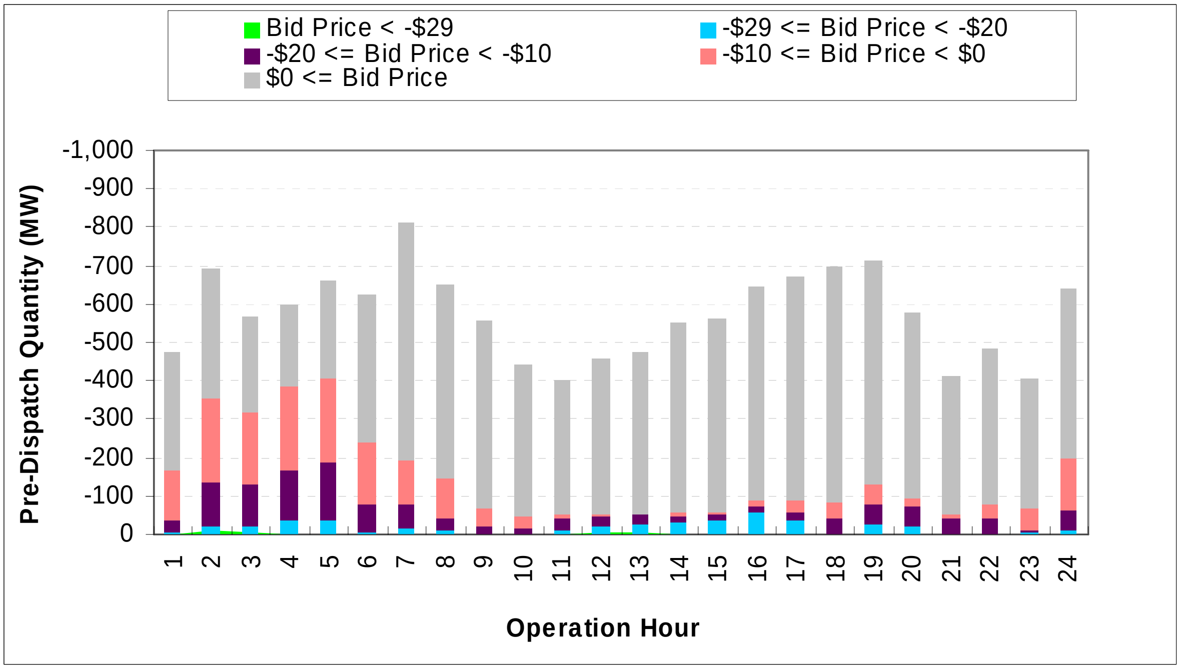
System conditions this spring also resulted in an unusual and high degree of loop flow mitigation, where unscheduled counter-clockwise loop flows were causing north-to-south congestion on Path 26. This physical phenomenon was due in part to the unusually high hydroelectric production in Northern California 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

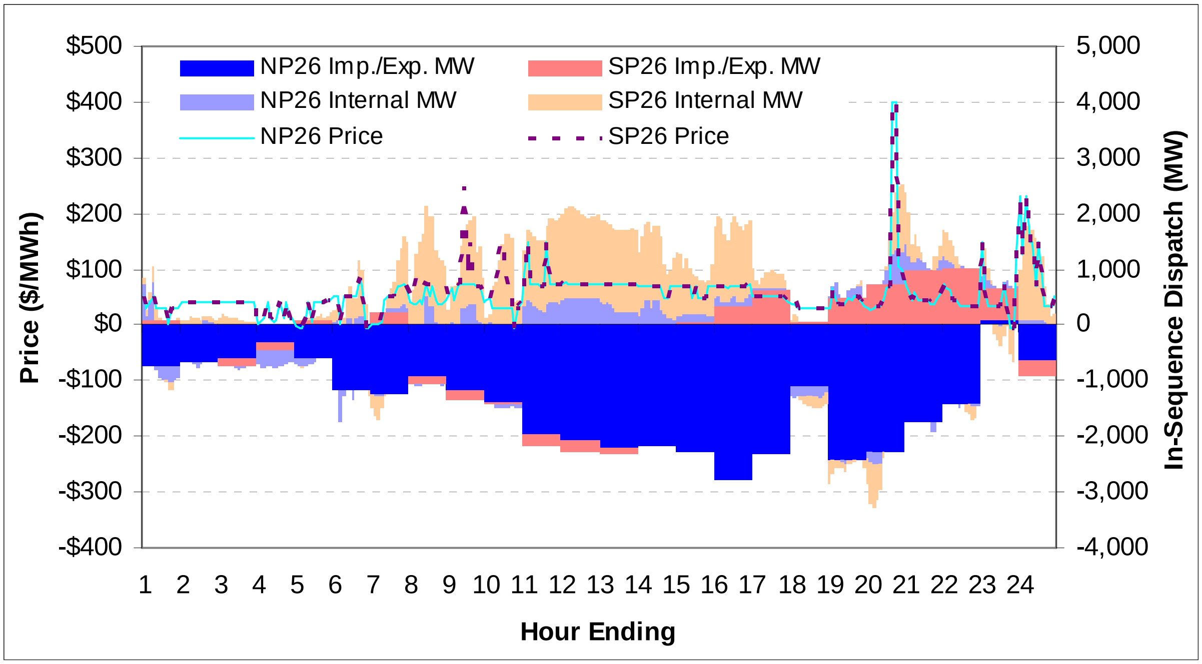


In addition to the high export volumes to the Northwest, pre-dispatch imports into Southern California were constrained by the Southern California Import Transmission Nomogram (SCIT), which is a physical limit on the instantaneous import of power into the Los Angeles basin. Because of this constraint, 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.

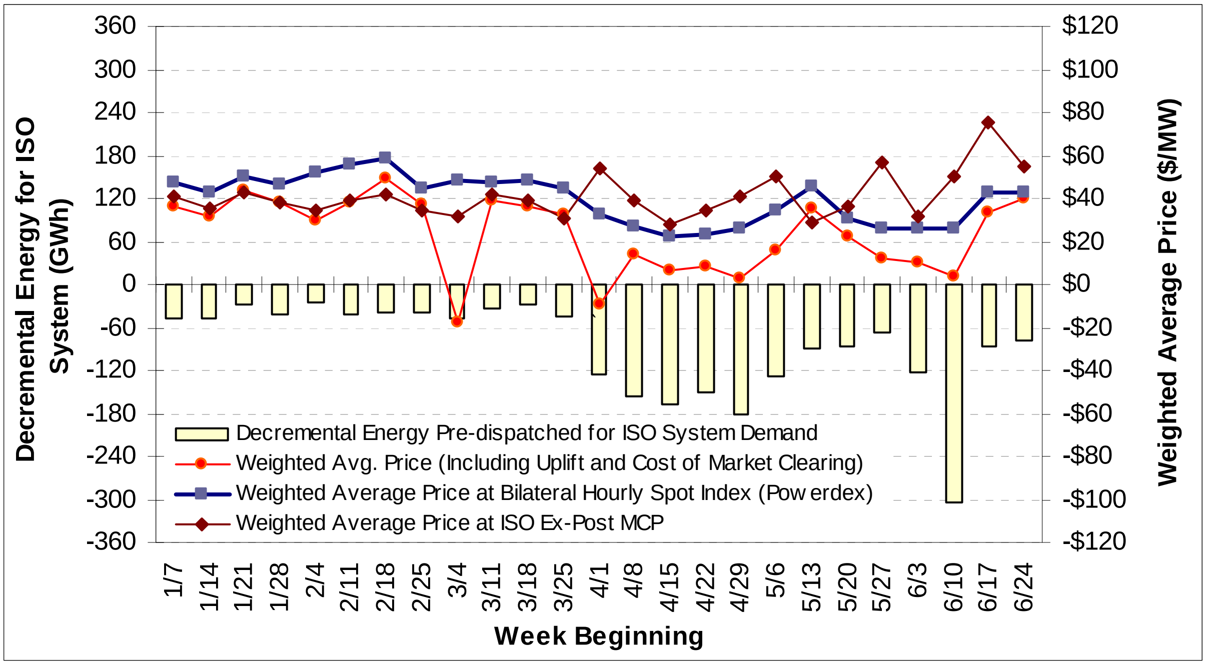
Figure 2.13 Pre-dispatch and Internal Dispatch Quantities for April 6, 2006



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).

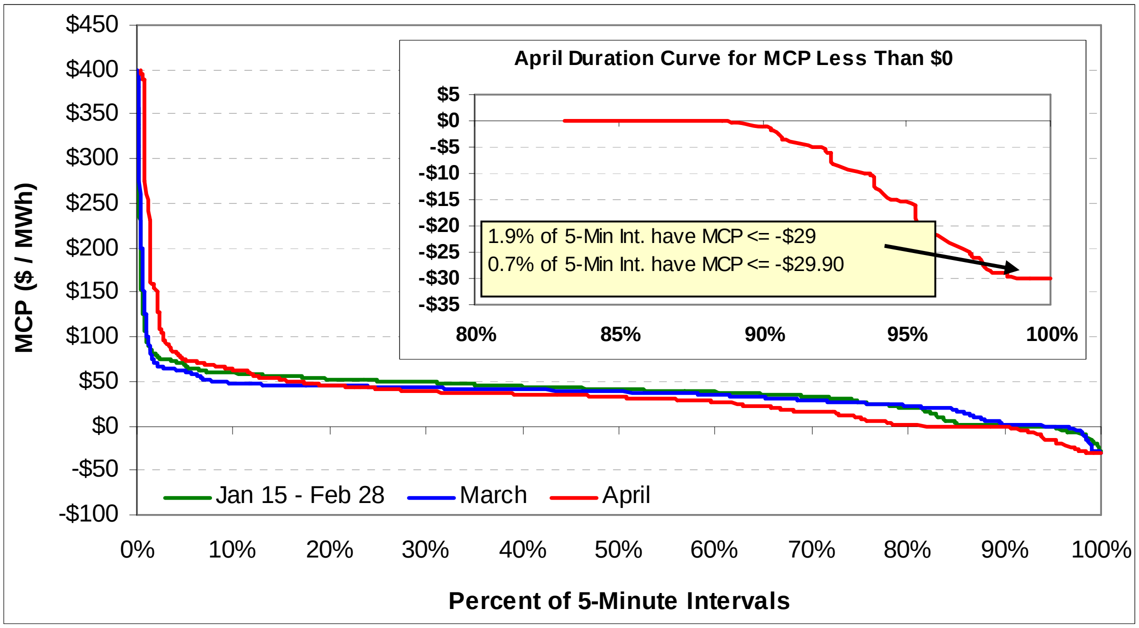
Figure 2.14 Price Divergence Between Real Time Pre-dispatch and Five-Minute Dispatch (January – April 2006)



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.

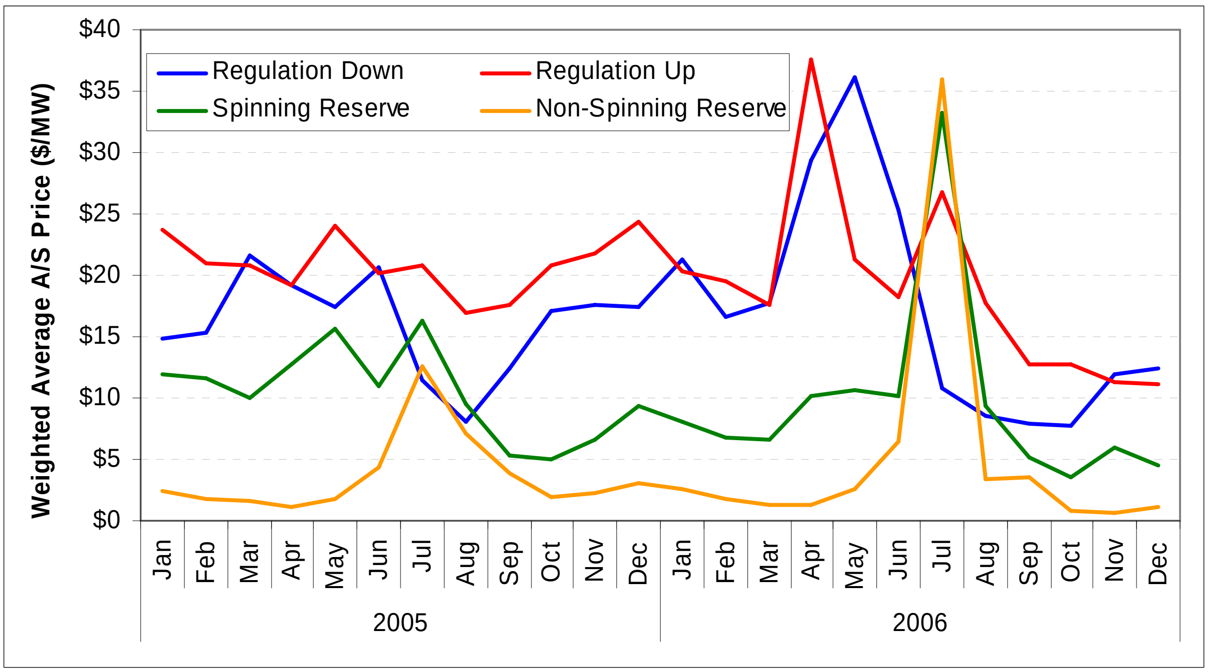
In April, the NP26 real-time price, which is predominantly the lower of the two zonal prices when Path 26 is congested, was below -$29/MWh in 1.9 percent of intervals, and below -$29.90/MWh in 0.7 percent of intervals. In addition, the frequency of pre-dispatched export bids below -$29/MWh was also very 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.

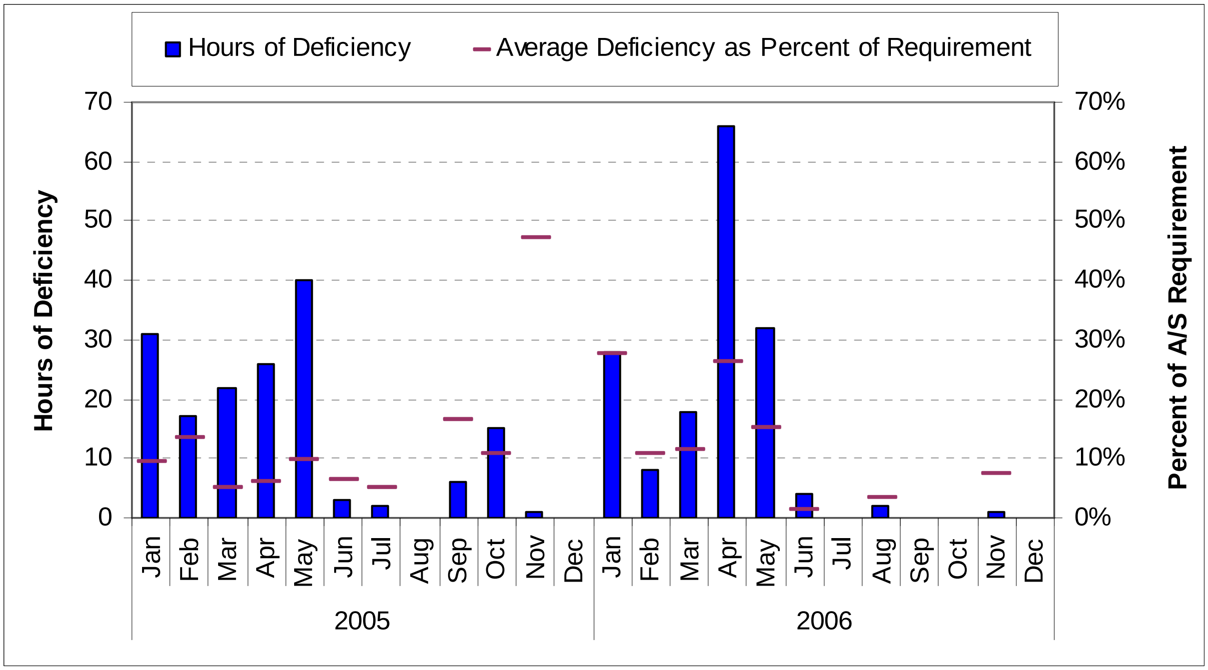
The price impact of high hydroelectric production in the winter and spring can be seen in Figure 2.16 below, where market clearing prices in the Regulating Reserves spiked in April and May.

Figure 2.16 Monthly Average Ancillary Service Market Clearing Prices



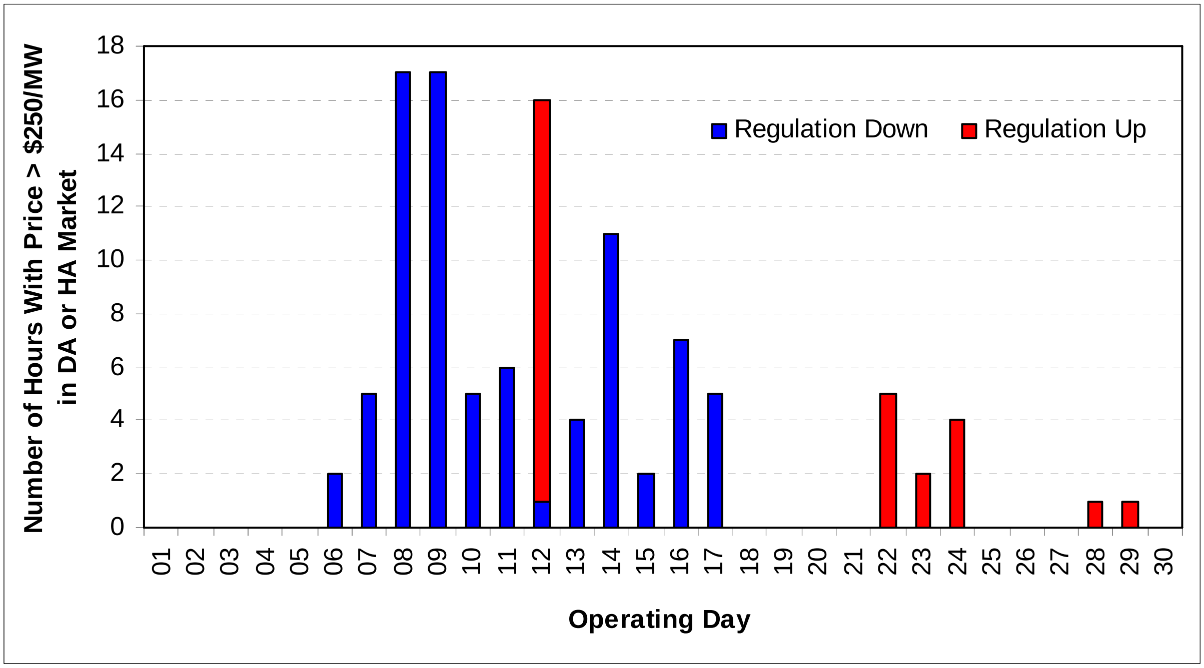
The price spikes in Regulating Reserve during April and May can be directly attributed to hours of bid insufficiency where supply of these reserves was reduced by the impacts of high runoff on hydroelectric production and consequent reduction of supply of Regulating Reserves. Figure 2.17 shows the dramatic 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.

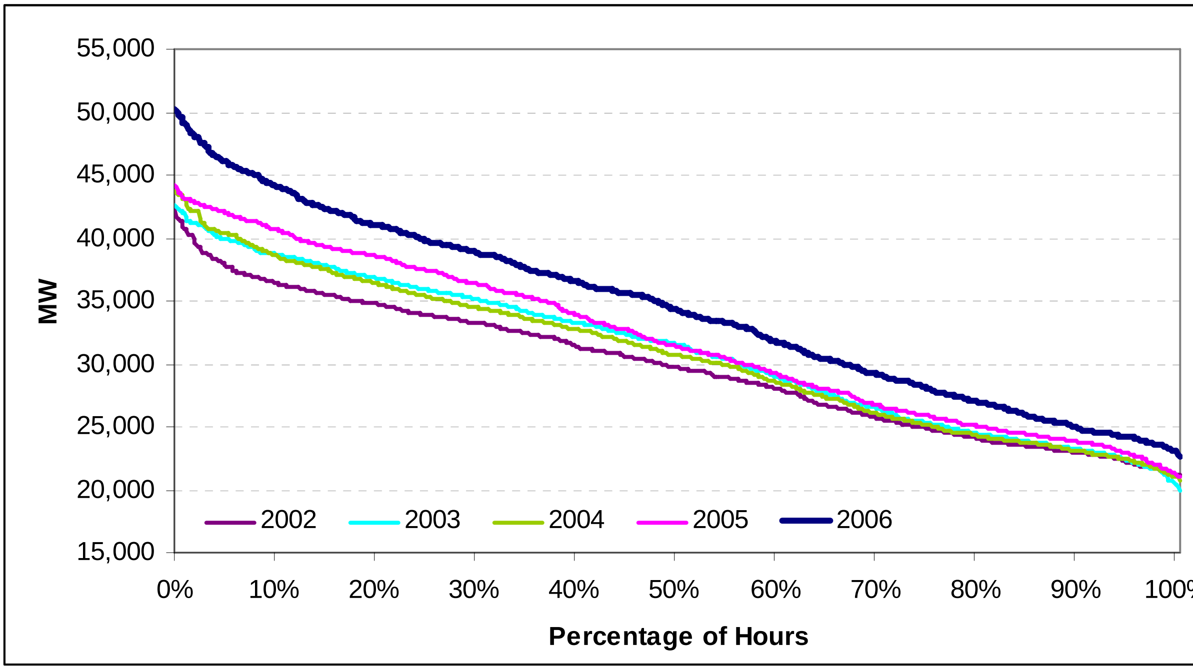
- **Prices in the CAISO Ancillary Service Markets generally followed prevailing day-ahead bilateral prices during much of the heat wave.** Since ancillary services are procured on a forward basis (day-ahead and hour-ahead), they reflected the opportunity costs of offering the generation capacity as reserve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

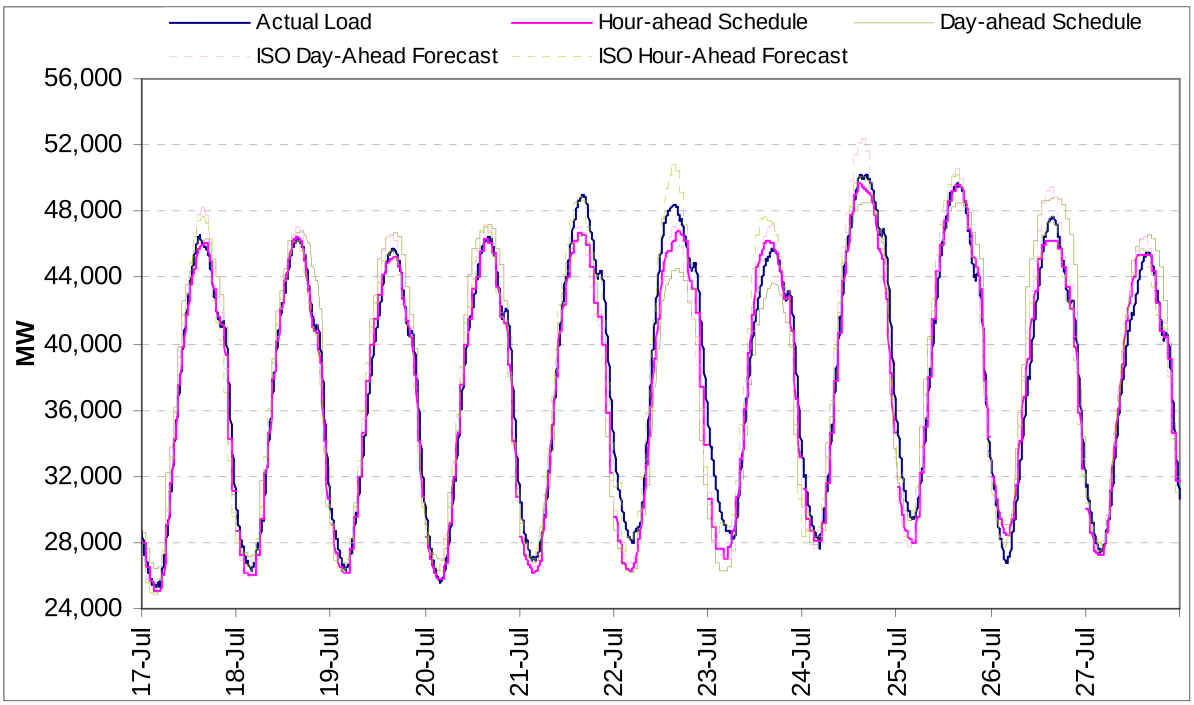
Forward scheduling was substantial, covering at least 95 percent of load at every peak during the heat wave. In addition, little generation was committed through the CAISO must-offer waiver denial process. Nearly all generation was self-committed in response to high day-ahead market price signals. The 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.

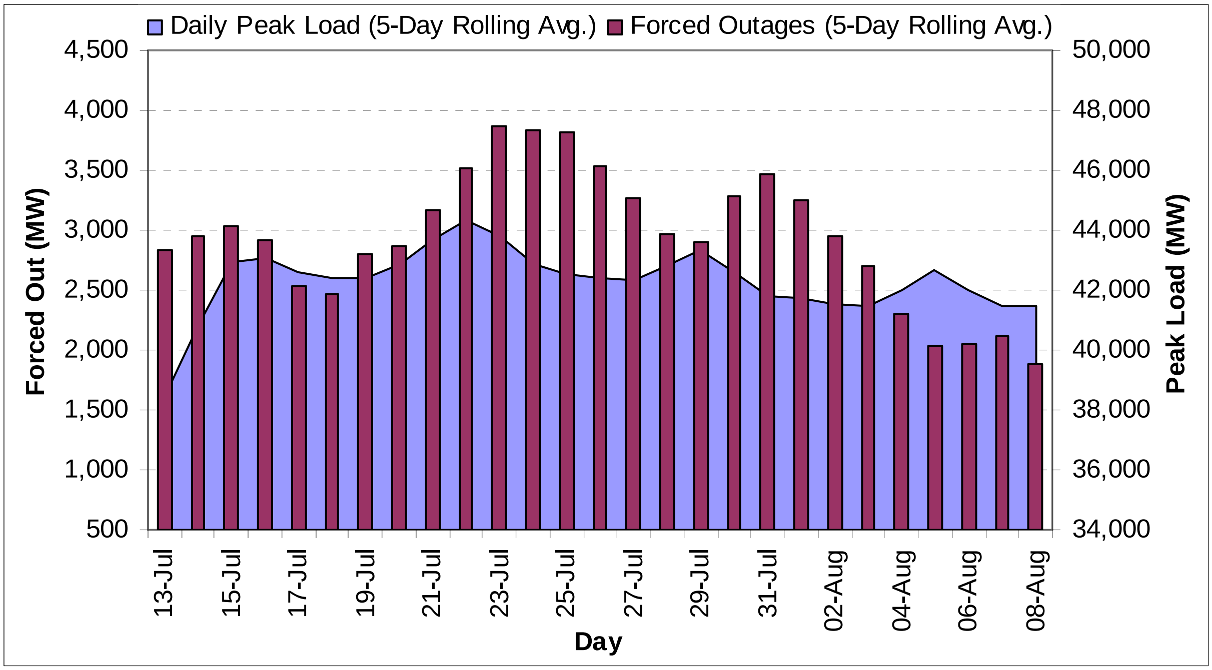
Generation Outages

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.

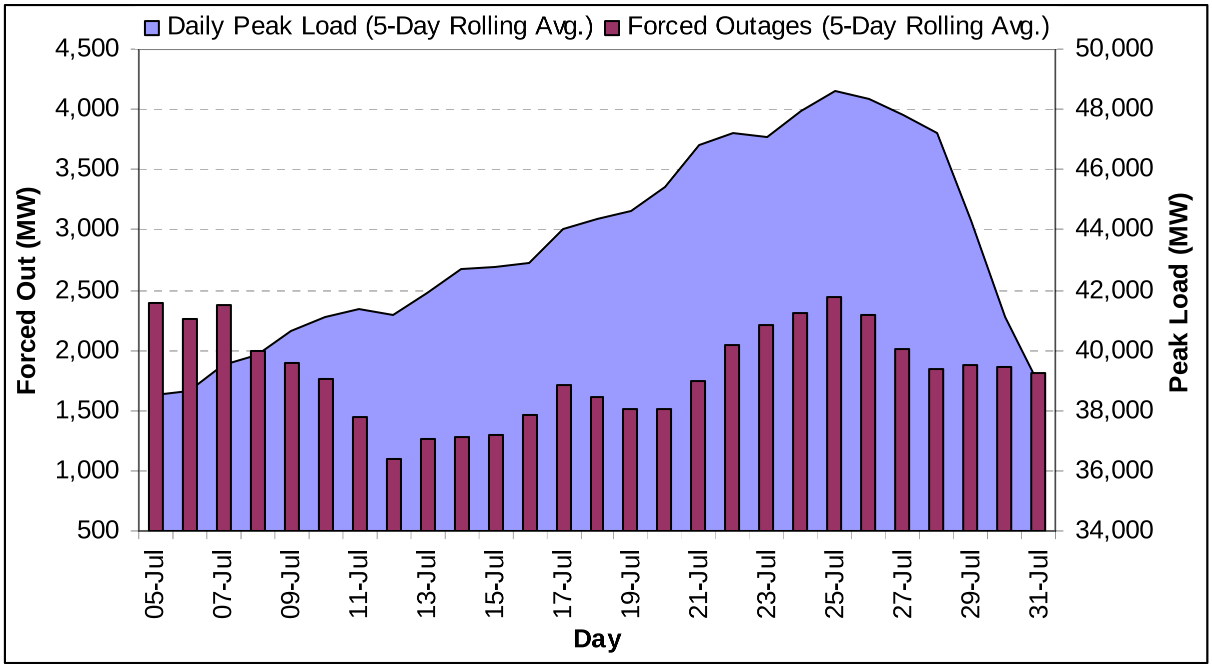
[8] July 24 peak was prior to curtailment.

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

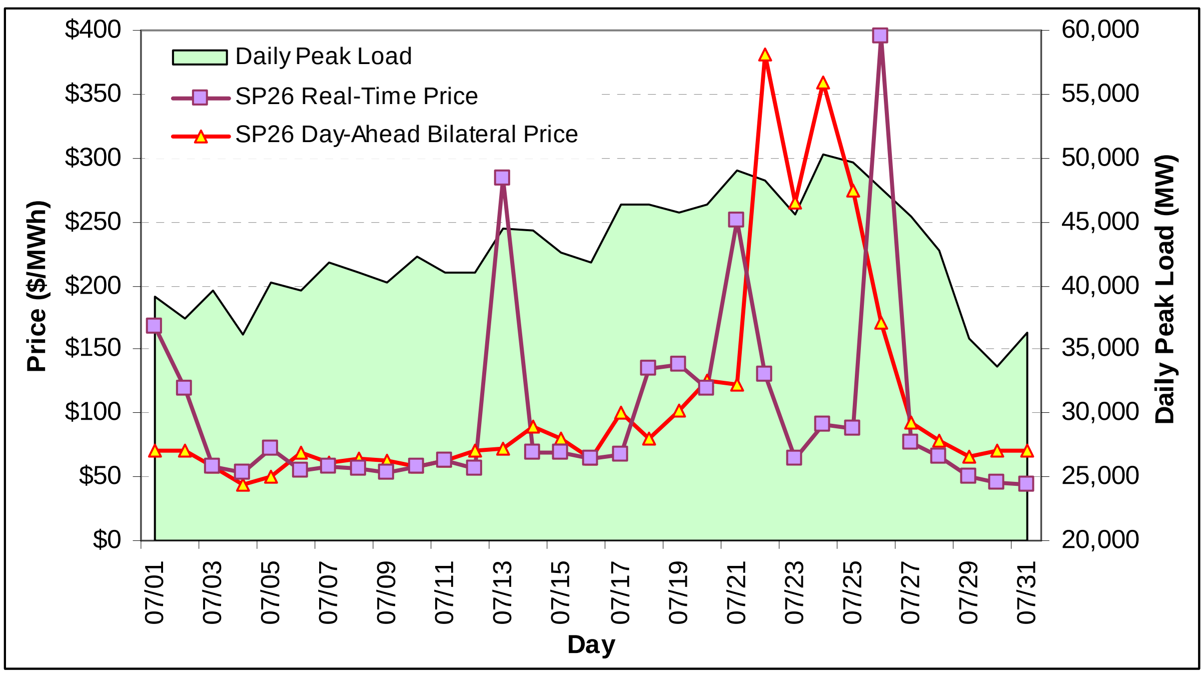


Figure 2.23 shows that peak day-ahead bilateral prices increased dramatically during the crest of the heat wave (July 22 – 25) when loads were at their highest – but the hourly CAISO Real Time Market prices during those same peak hours actually declined and were substantially below day-ahead bilateral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

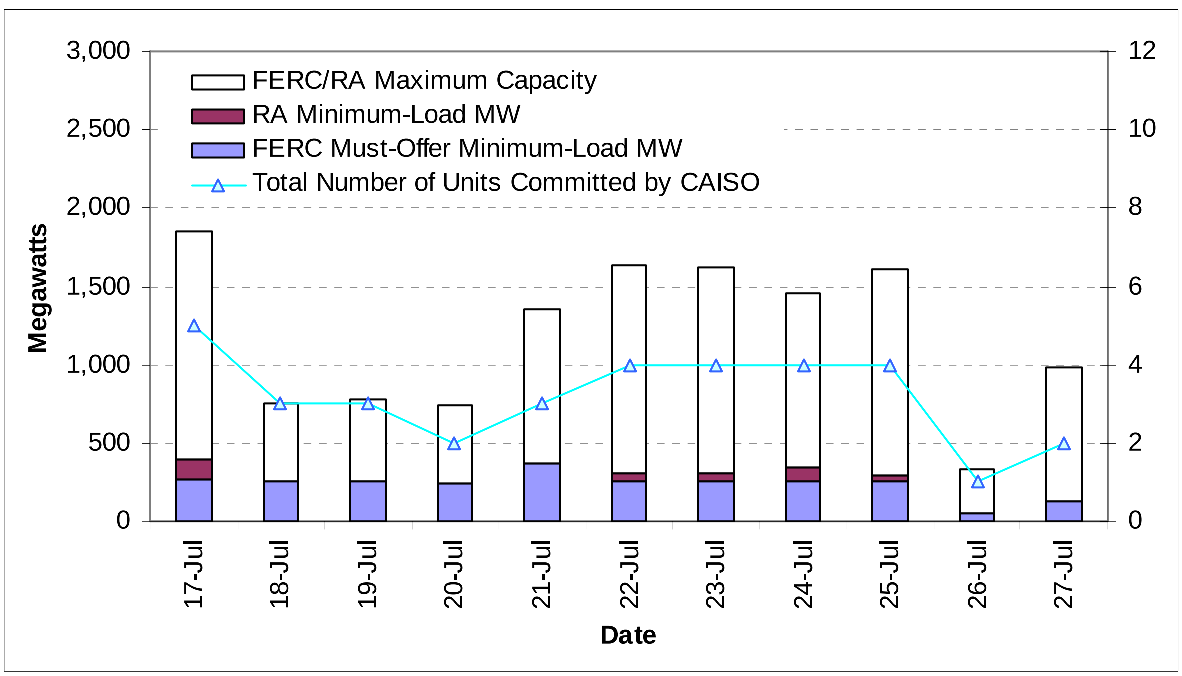
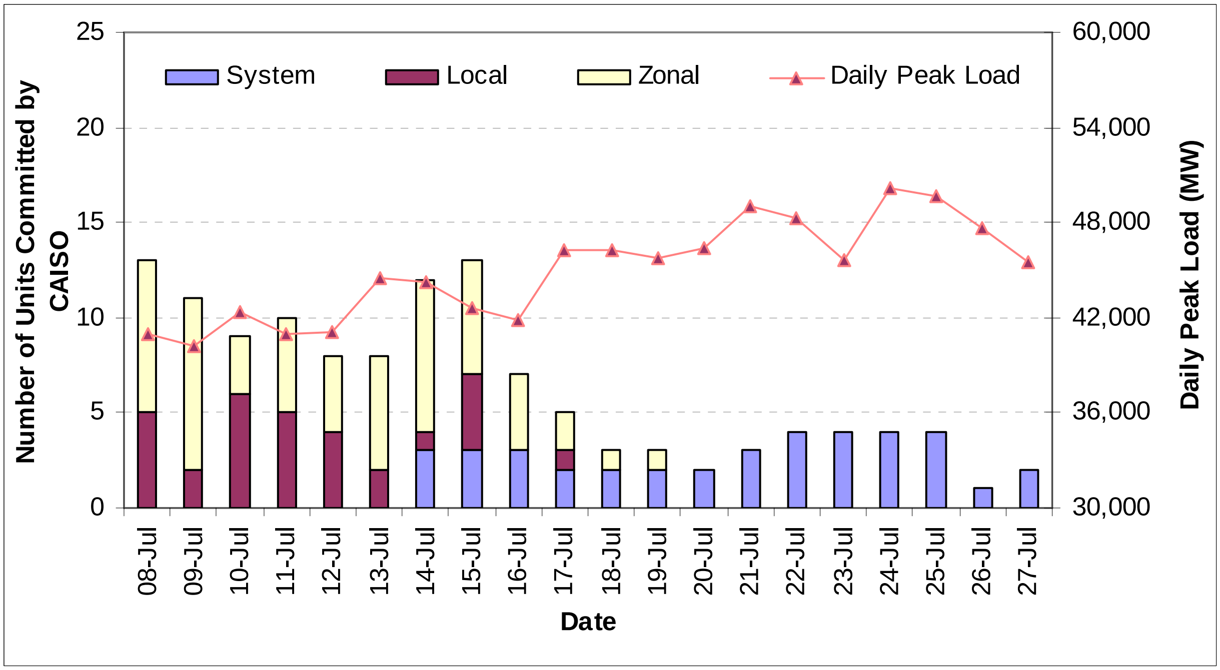


Figure 2.25 Units Committed during Heat Wave by Commitment Type

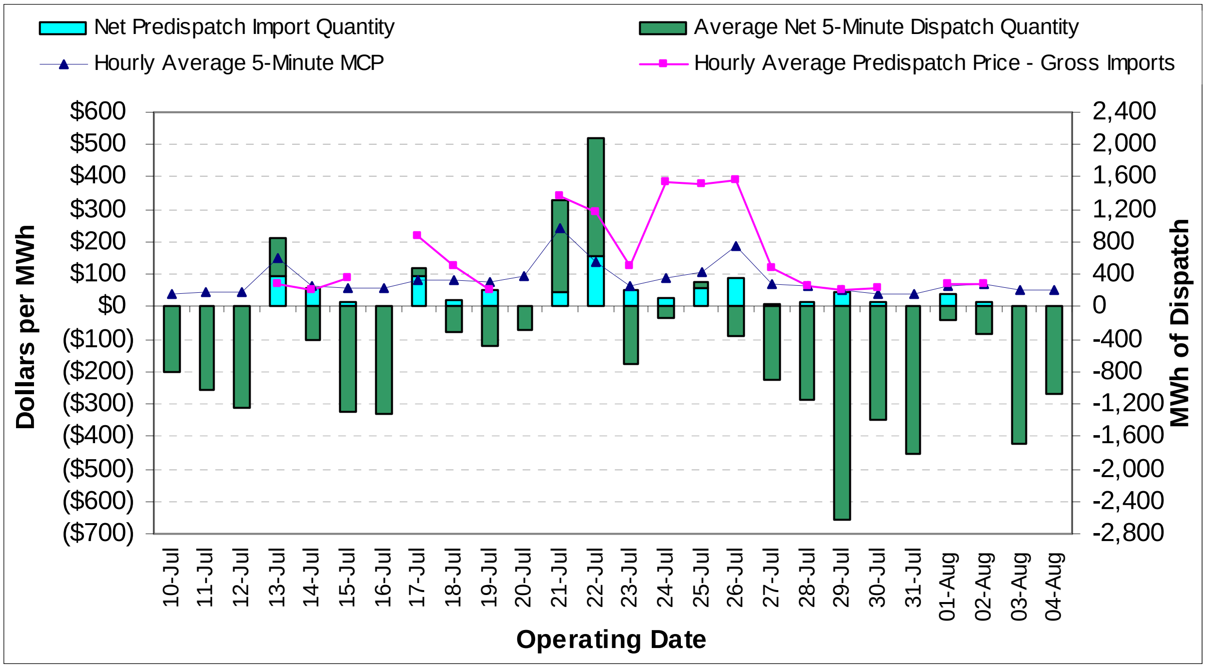


Pre-dispatched System Resources

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

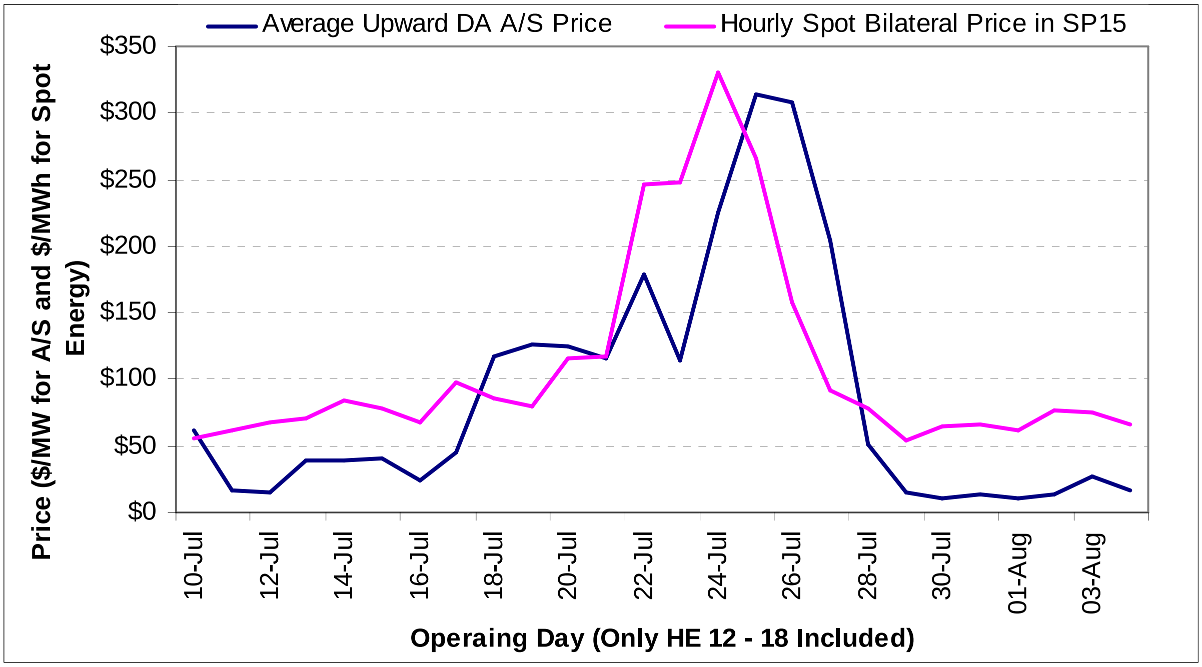
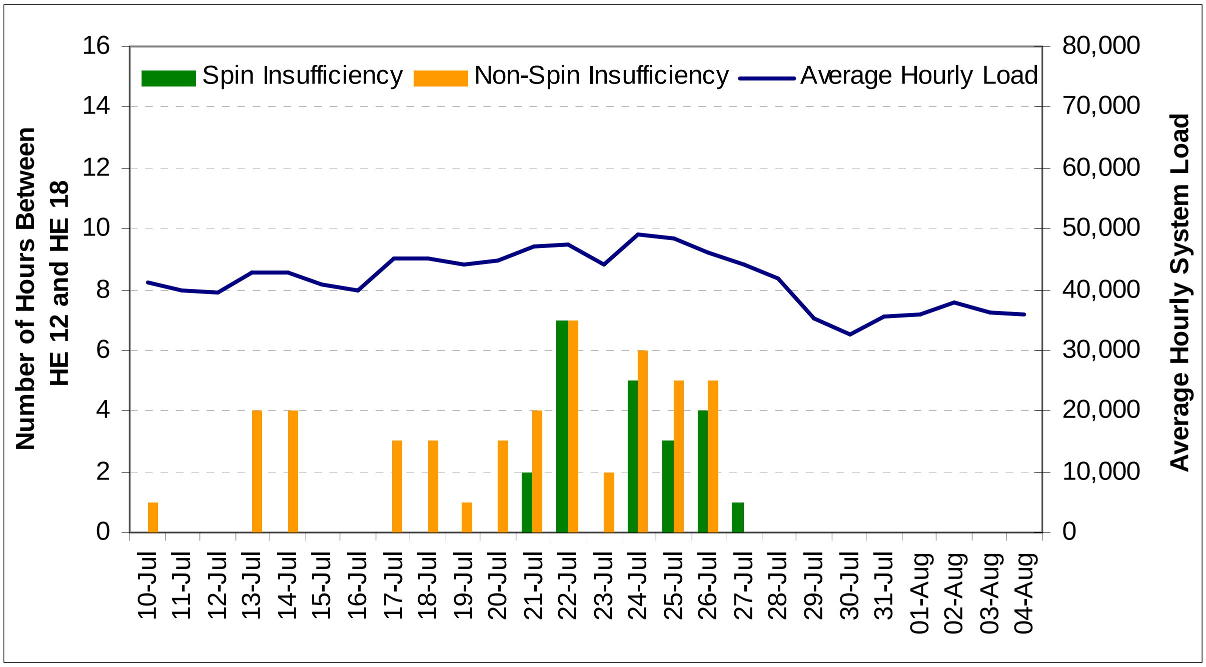


Figure 2.27 shows that the average price of upward Ancillary Services (Regulation-Up, Spinning Reserve, and Non-Spinning Reserve) purchased in the day-ahead market clearly reflect (a) the opportunity cost of offering the generation capacity as reserve as opposed to selling the energy in the bilateral 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.

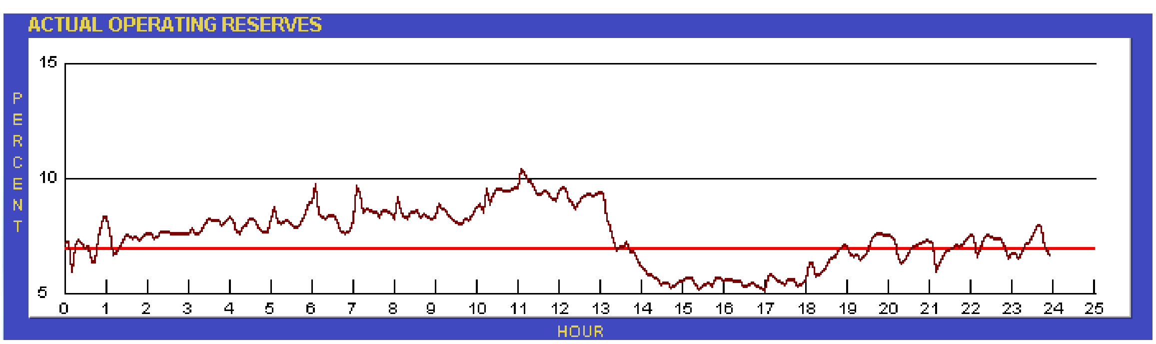
Figure 2.28 Ancillary Service Bid Insufficiency (Hours 12-18)



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:

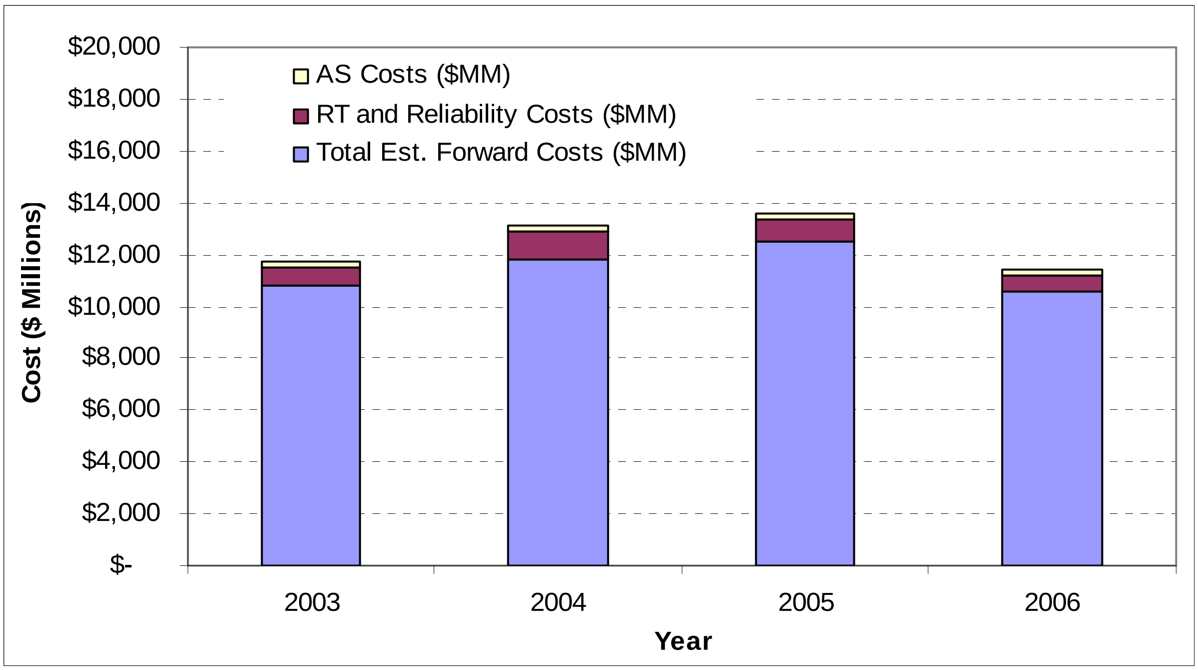
Forward energy costs revised slightly upward using a new methodology to include: utility-retained generation at estimated production costs, long-term contract (formerly managed by CDWR/CERS) estimated using 2002 delivery volumes; and short-term bilateral procurement estimated at utility-supplied procurement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

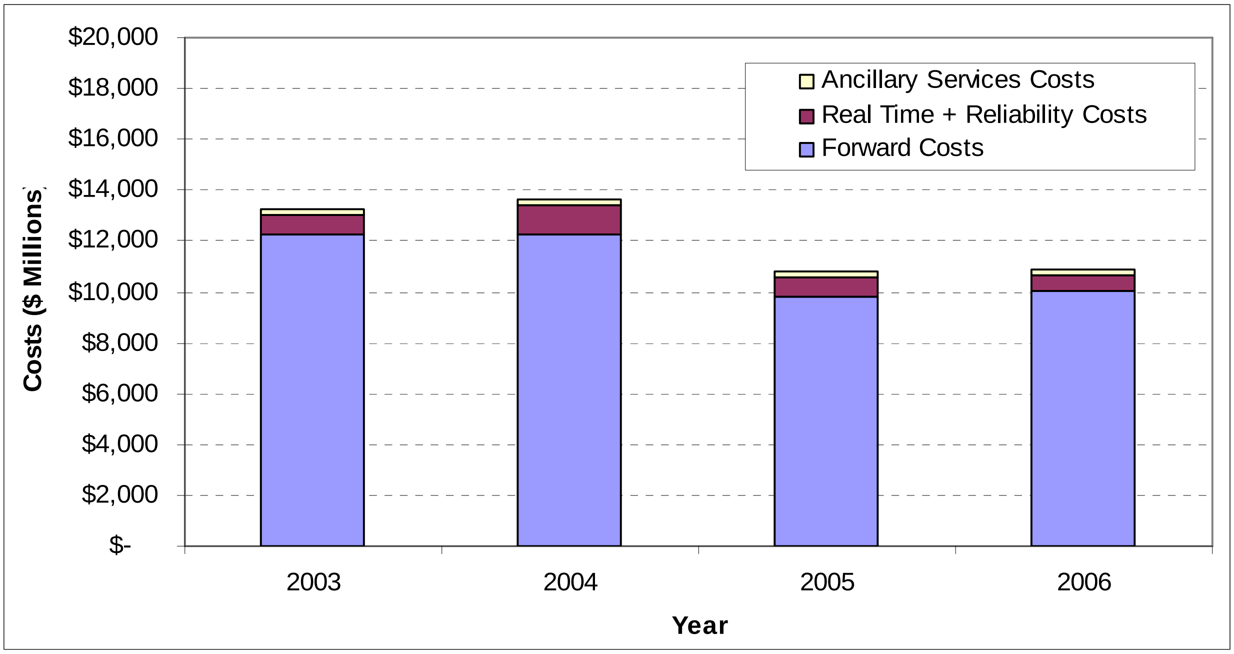
Figure 2.30 Total Wholesale Costs: 2003-2006



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.

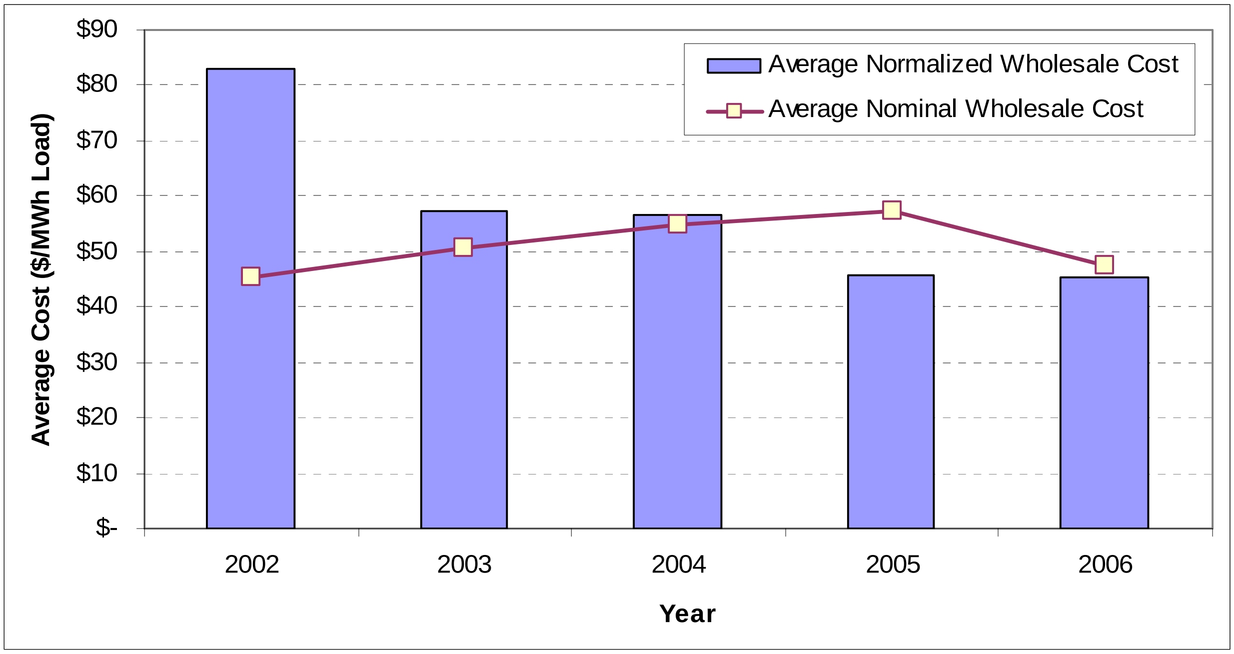
Table 2.8 Contributions to Estimated Average Wholesale Energy Costs, 2002-2006[12]

	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*

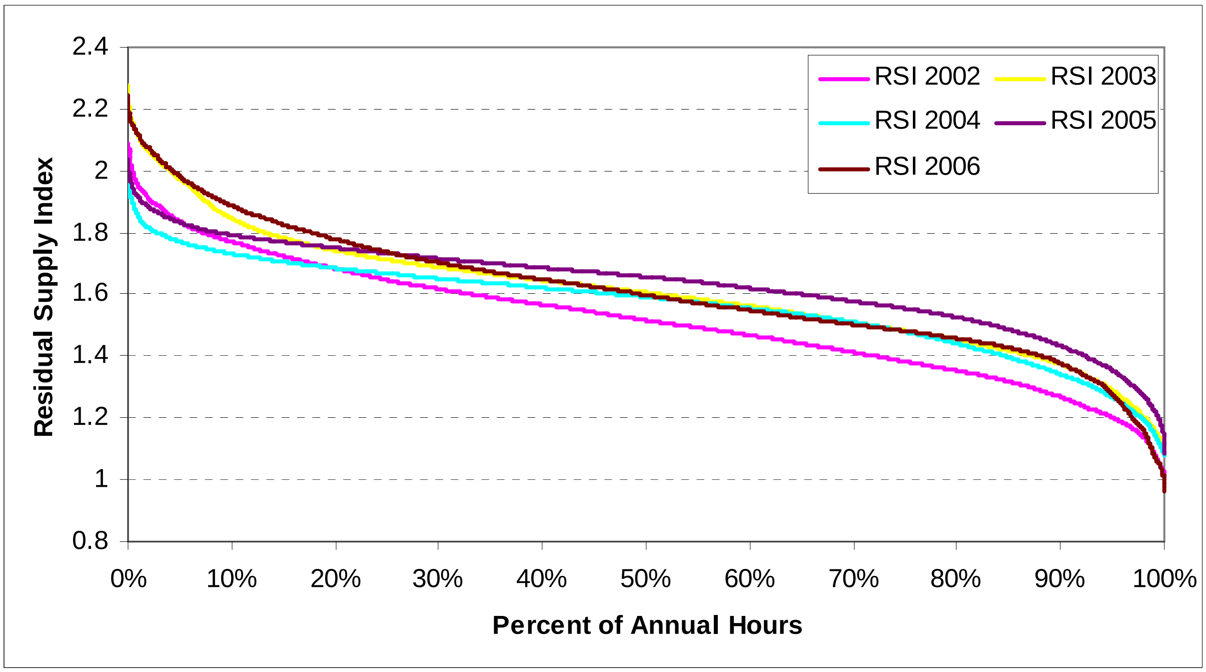
LSS_i = Supply of Largest Single Supplier in hour *i*

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.

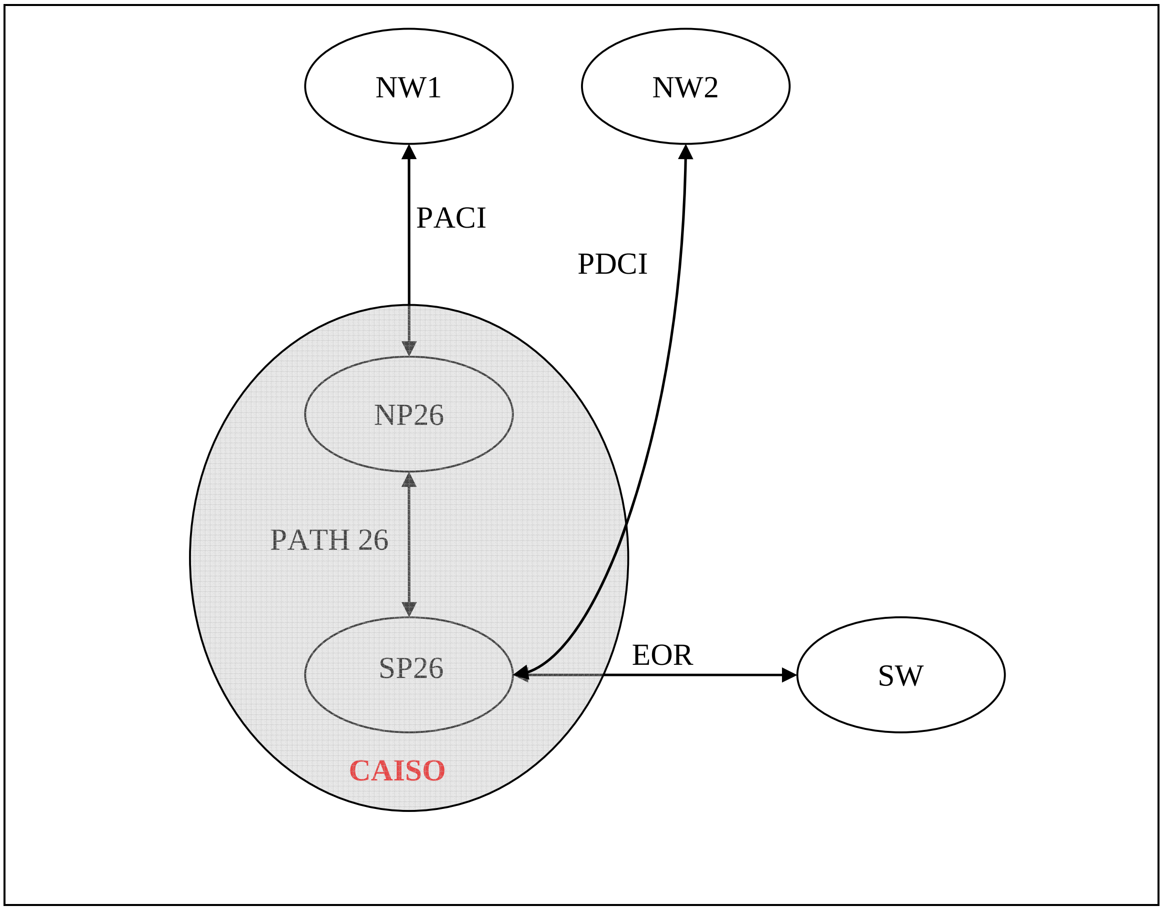
Previous Annual Reports have implemented several index constructs yielding measures of market competitiveness in the short-term energy markets. Those indices have been based on several price sources ranging from CAISO market data and information from bilateral forward contracts to prices from the Department 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.

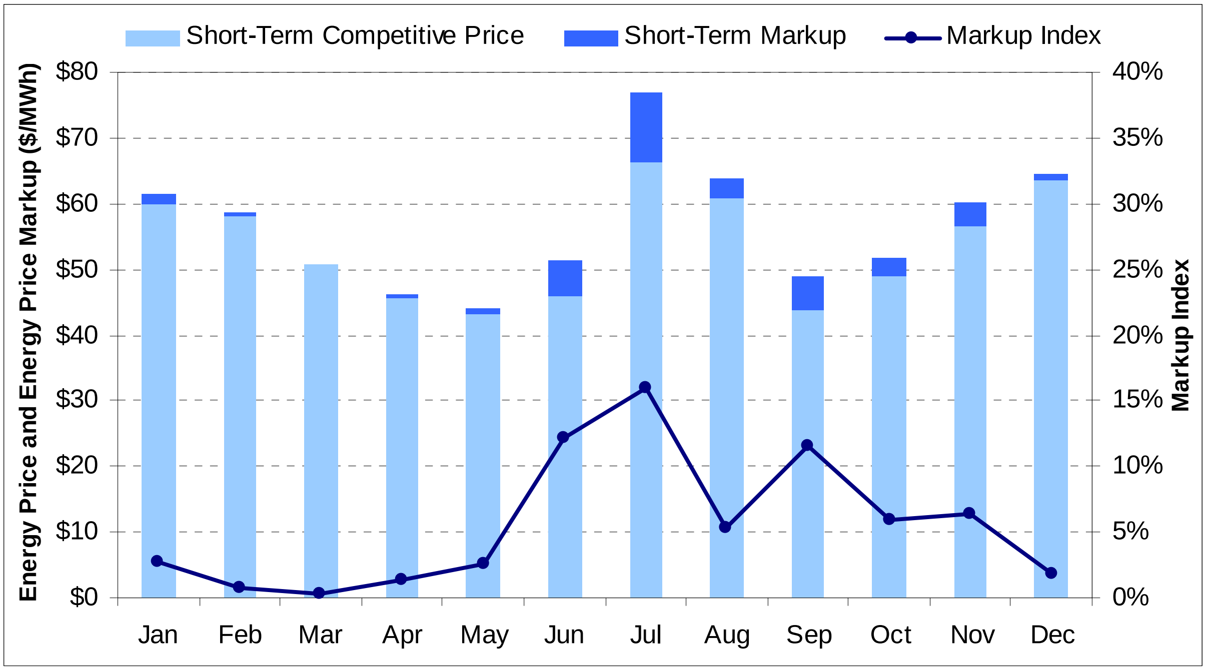
Figure 2.34 Simplified Network Topology Used in Competitive Price Simulation



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.

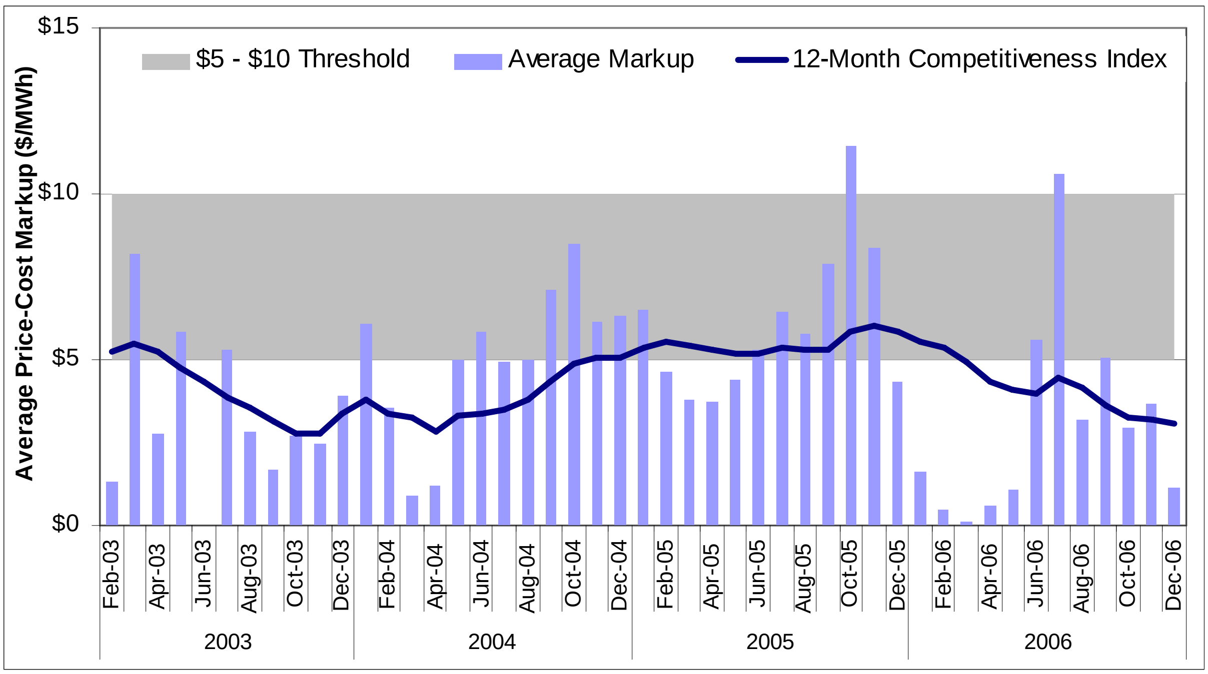
Figure 2.35 2006 Short-term Forward Market Index



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:

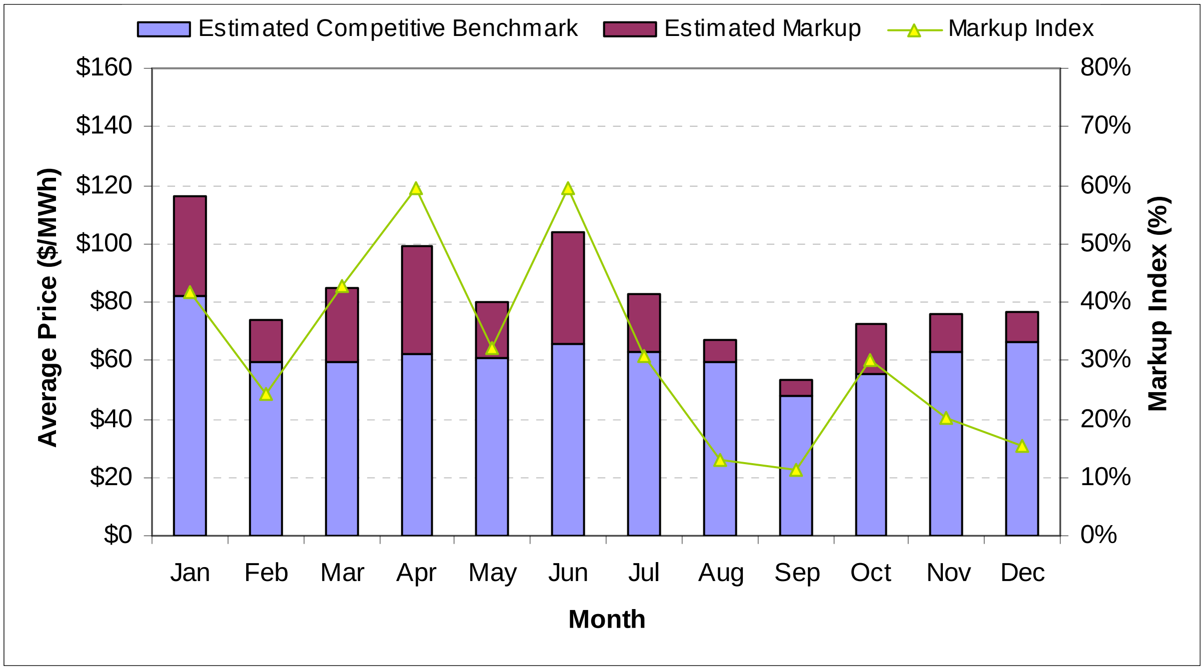
- Price spikes are often a result of limited available 5-minute ramping energy during morning or evening load pull periods when the CAISO needs to dispatch increasing amounts of energy in real time to match or catch the load ramp. An abundance of hydro generation in the first half of 2006 decreased the 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

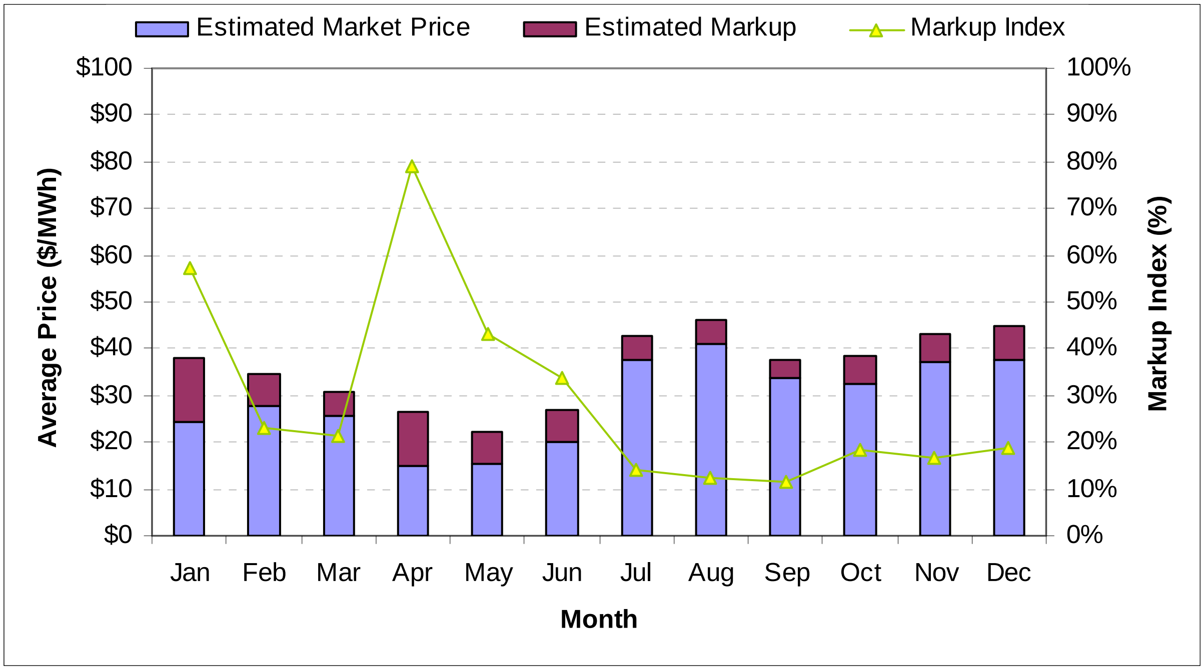


April and June featured the highest monthly incremental mark-ups; mark-ups reached approximately 59.5 percent of competitive benchmarks in both of these months. Indeed, five of the top ten incremental mark-up days in 2006 were in April. These were largely during ramping periods in early mornings and 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

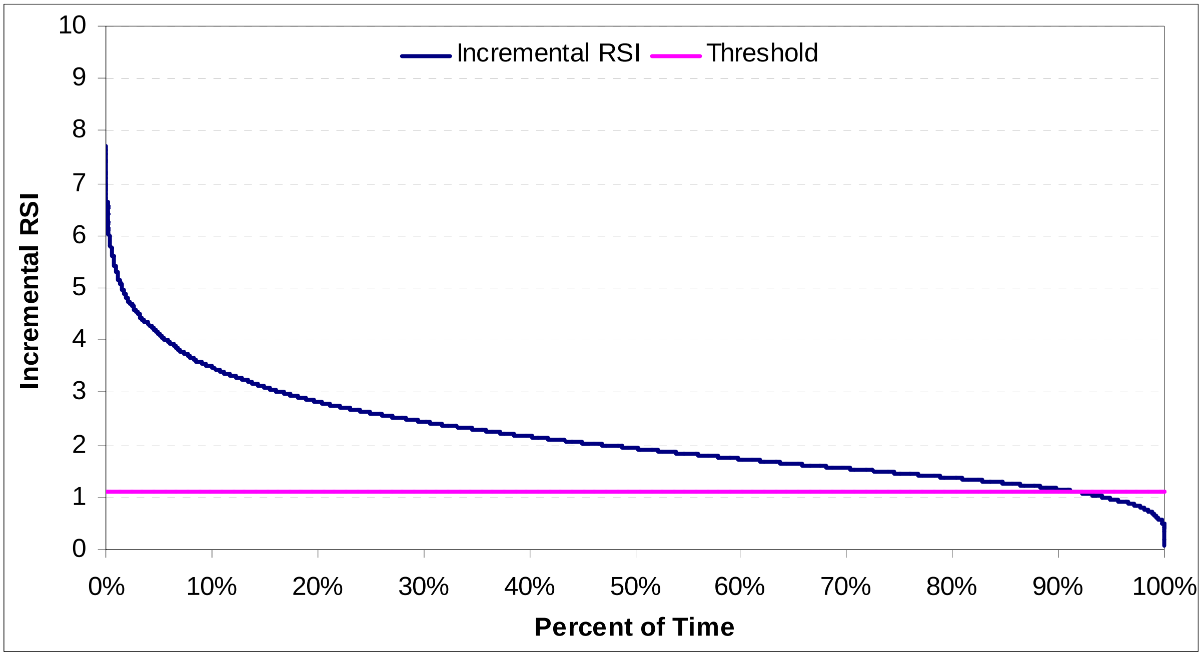


Figure 2.40 RSI Relationship to Real-time Incremental Market Clearing Prices

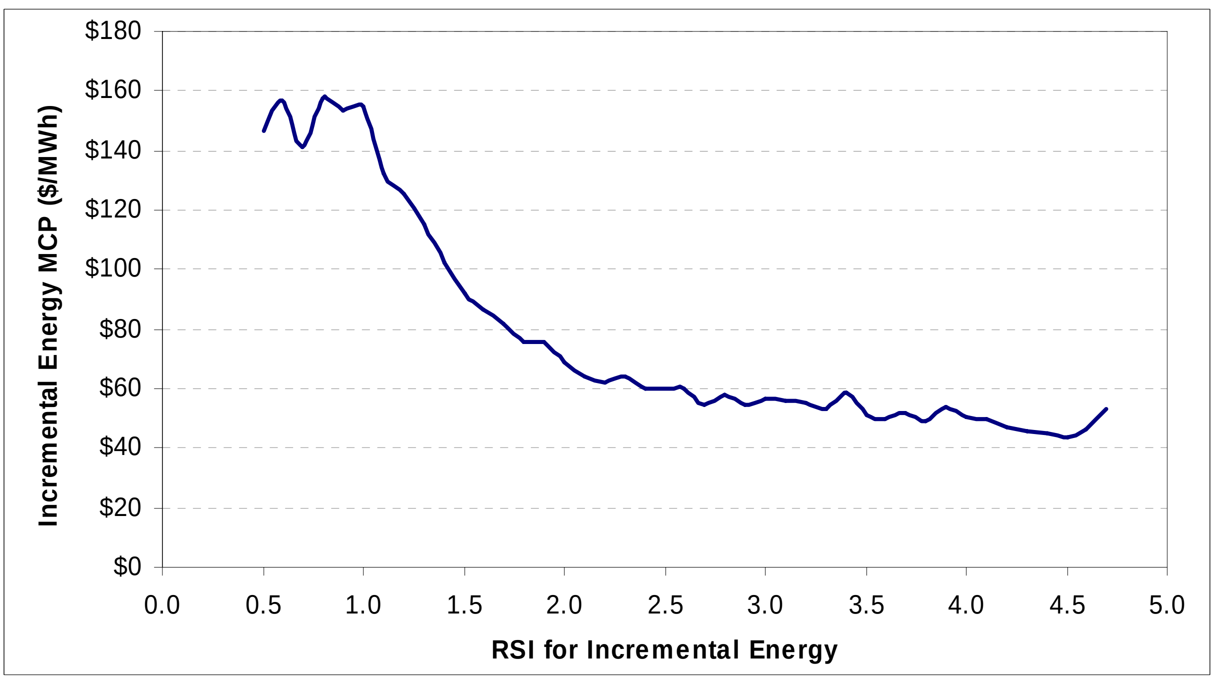


Figure 2.41 shows the RSI duration curve during decremental energy dispatch periods. In 2006, RSI values dipped below 1.1 for 13 percent of the time. RSI values for decremental supply tend to be low in off-peak hours when generators are operating close to their minimum output level and unwilling or unable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

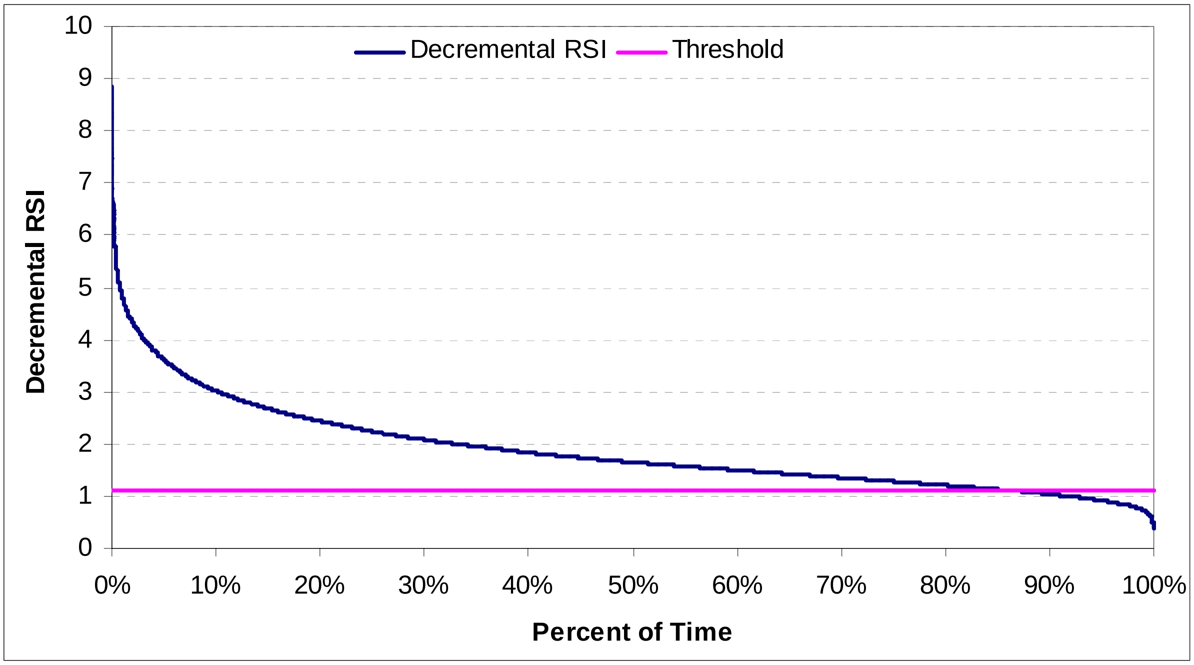
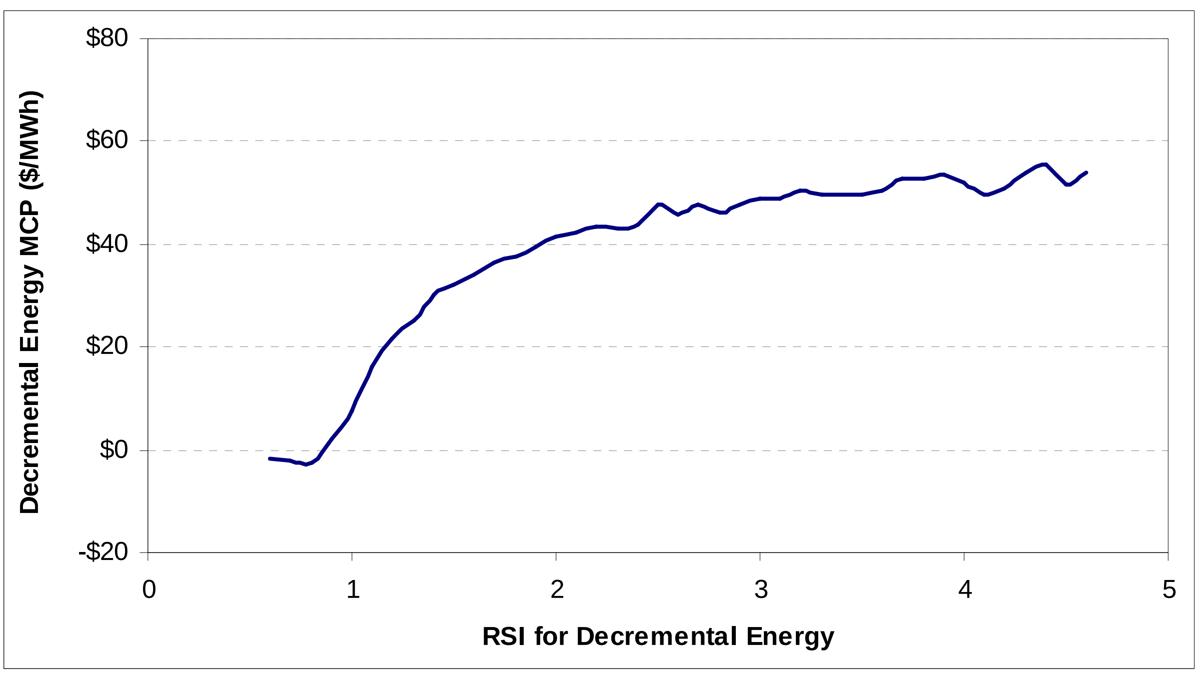


Figure 2.42 RSI Relationship to Real-time Decremental Market Clearing Prices



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.

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[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.

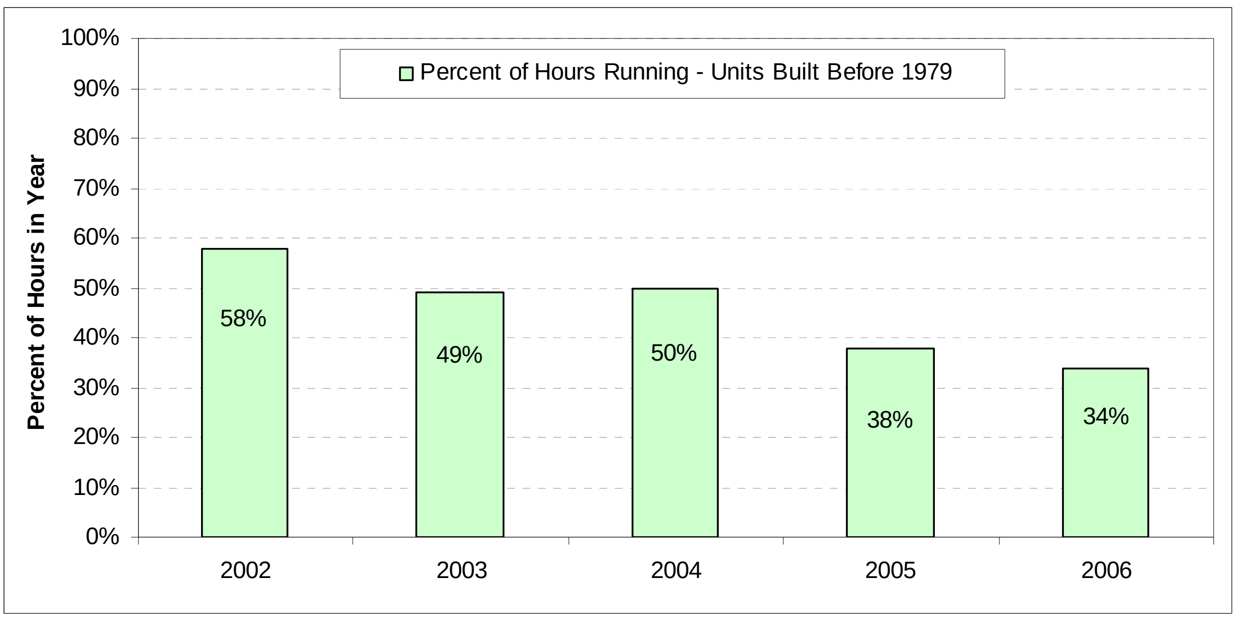
[17] It is important to note that this table only shows part of the supply picture in SP15. Numerous transmission upgrades have also occurred within SP15 to improve generation deliverability within the zone; however, despite these improvements, meeting summer peak load demands in SP15 remains extremely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