2. Summary of 2004 Energy Market Performance

2.1 Supply and Demand Conditions

2.1.1 Loads

On average, loads increased approximately 4 percent between 2003 and 2004. The Department of Market Analysis calculates four load growth metrics. These are year-to-year comparisons of monthly average load, average daily peak load, average daily trough (minimum) load, and peak load for the entire period. All showed increases of between 3.5 and 4.9 percent on an annual basis. When we compared the same months in 2003 and 2004 (e.g., January 2003 vs. January 2004), nearly all metrics showed increases (11 out of 12 months). These indicated load growth that cannot be completely explained by variation in weather. The single month for which load indices decreased was October. This month was unseasonably mild in 2004. Even with mild weather, our year-to-year comparison of the average daily trough, which tends to be less sensitive to weather variation than the average and peak comparisons, increased 1.5 percent in October. Table 2.1 shows same-month comparisons of the four load metrics between 2003 and 2004.

Table 2.1 Load Growth Rates: Comparisons to the Same Month in the Previous Year

	Avg. Hrly. Load	Avg. Daily Peak	Avg. Daily Trough	Monthly Peak
January-04	4.3%	3.1%	5.1%	3.2%
February-04	4.5%	3.9%	5.4%	4.5%
March-04	4.4%	5.1%	2.5%	4.5%
April-04	7.1%	8.3%	4.8%	31.1%
May-04	7.3%	7.7%	5.5%	2.5%
June-04	6.6%	6.9%	6.1%	-4.7%
July-04	0.7%	0.3%	1.9%	4.0%
August-04	1.0%	0.6%	0.6%	5.2%
September-04	3.4%	3.5%	3.4%	10.1%
October-04	-1.4%	-2.8%	1.5%	-5.9%
November-04	4.2%	3.9%	3.9%	6.6%
December-04	4.4%	4.1%	6.5%	3.4%

Southern California has experienced growth at a higher rate than northern California, in large part due to rapidly expanding population in the Inland Empire area.

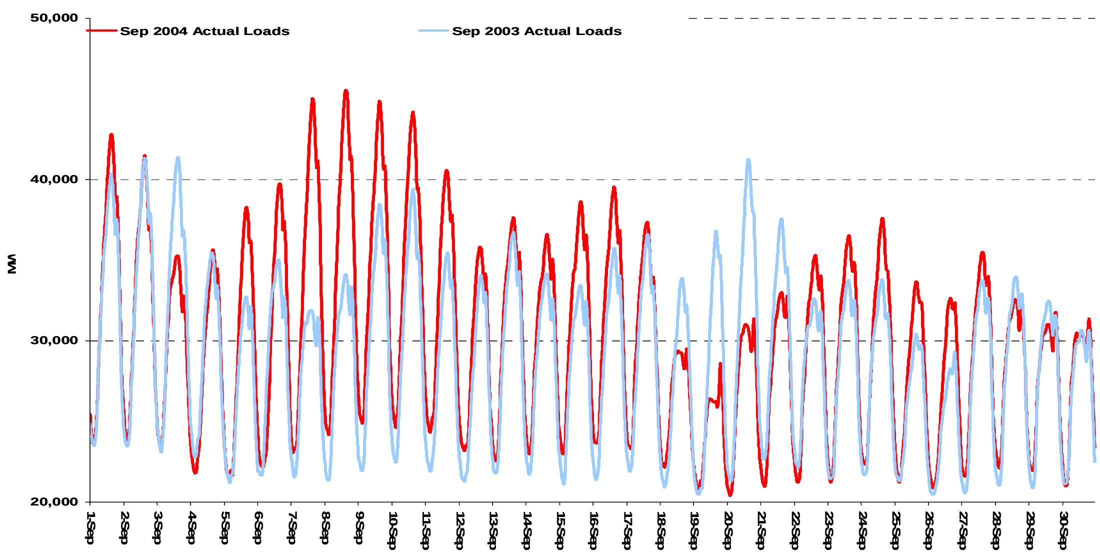
Annual Peak. Both zones experienced peak loads at approximately the same time in 2004, during a state-wide heat wave between September 7 and 10. Peaks occurred in different months in 2003. As a result, the Control Area peak was substantially higher in 2004. The CAISO set a new all-time record peak load (when adjusted for the exit of SMUD from the control area)[1] of 45,597 MW on the afternoon of September 8, 2004. Two days later, on September 10, 2004, between 3:00 and 4:00 p.m. (HE 16:00), SP15 load reached a new all-time peak of 25,743 MW due to high temperatures across southern California, although not at levels typically seen on a peak day. Figure 2.1 compares actual hourly average loads in September 2004 and 2003.

Table 2.2 shows yearly average growth rates in NP15 and SP15, and for the CAISO as a whole.

Table 2.2 Yearly Growth Rates by Zone

Zone	Avg. Hrly. Load	Daily Peak Load	Daily Trough Load	Annual Peak
NP15	3.1%	3.1%	2.6%	1.3%
SP15	4.2%	3.7%	4.8%	4.6%
ISO Control Area	3.7%	3.5%	3.8%	7.0%

Figure 2.1 Actual Loads, September 2004 v. September 2003



2.1.2 Supply

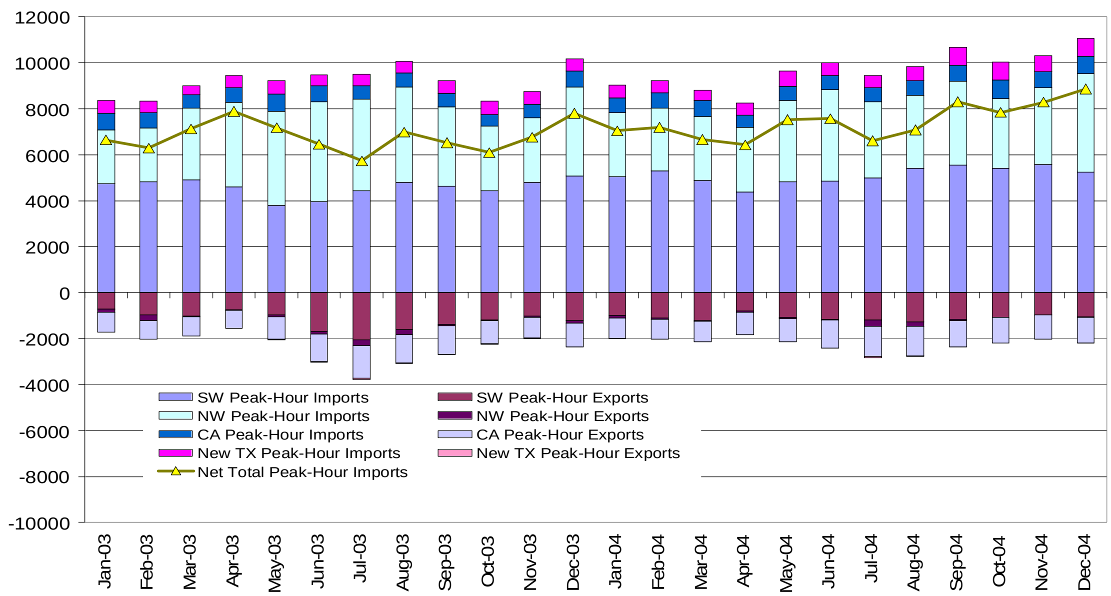
2.1.2.1 Imports and Exports

Net imported energy has been trending upwards for the past three years as significant amounts of new efficient generation units have been built in the southwest and to a lesser extent in the northwest. During 2004, imports from the Pacific Northwest were unusually low, due primarily to poor snowpack that limited the area's excess hydroelectric production. Low imports from the northwest were largely offset by strong

[1] Loads adjusted by taking out SMUD load from previous peak loads to provide accurate load comparison.

imports from the southwest, from new generation and due to mild temperatures in the spring and early summer in that region. Imports were also strong during the summer, the peak period of September 8-10, and into the fall season, when the typically hot southwest again had generation to spare. One side effect of the large quantity of imports was a strong increase in inter-zonal congestion, discussed in Chapter 5. Figure 2.2 shows monthly average imports and exports by origination/destination region, and net imports, for each month in 2003 and 2004.

Figure 2.2 Monthly Average Imports and Exports by Source/Destination, 2003-2004[2]

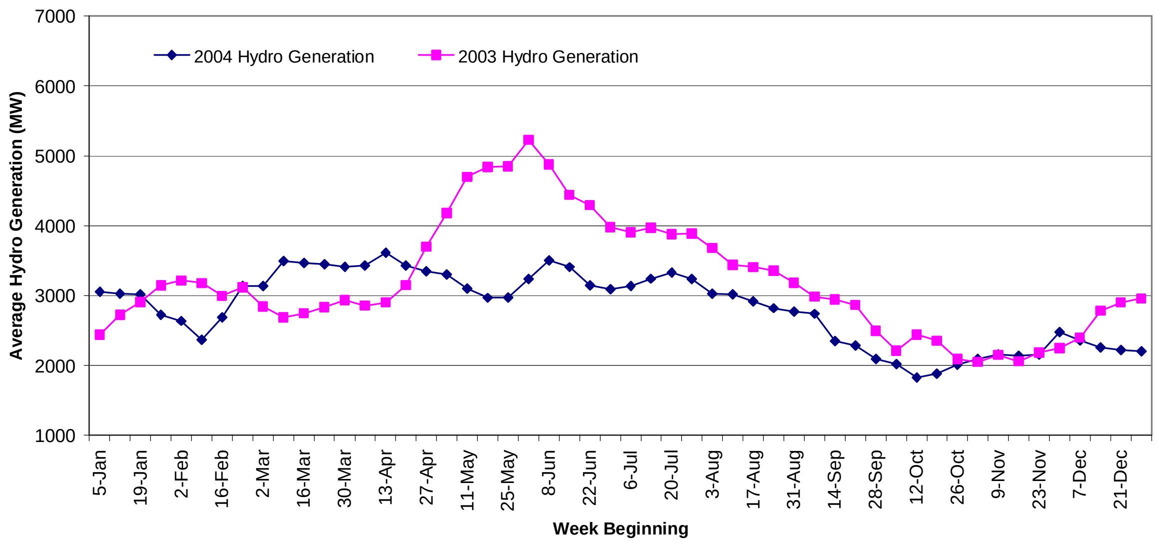


2.1.2.2 Hydro Generation

A robust early snowpack of approximately 120 percent of average in mid-February eroded to below 50 percent of average by early May, due to an unseasonably hot spring across the western United States. This heat wave lasted for much of March and April, peaking approximately at 103 degrees Fahrenheit in Ontario during the week of April 26. The resultant early spring hydro runoff caused hydroelectric energy production to exceed 2003 levels through mid-April, and then to remain well below 2003 levels through the summer and fall. Figure 2.3 compares weekly average CAISO system hydroelectric production across all hours, for 2004 and 2003.

2 "New TX" indicates new transmission added to the CAISO grid since January 2003. While this transmission connects southern California to the southwest, we have not included it in the "Southwest" data to avoid double-counting.

Figure 2.3 CAISO System Hydroelectric Generation: Weekly Averages (All Hours), 2004 v. 2003



2.1.2.3 Thermal Generation

2.1.2.3.1 Natural Gas Prices

Natural gas prices fluctuated between the $5.00 to $6.50/MMBtu range through much of the first two-thirds of 2004, affected by ongoing concerns about natural gas drilling and production. Prices were higher during the summer season owing to increased demand for natural gas for electrical generation.

Of particular import, however, is the distinct increase in natural gas prices after September. Colder temperatures throughout the east coast in September and October, along with lingering impacts on production from the multiple hurricanes striking the Gulf of Mexico, resulted in a sharp rise in natural gas prices to the $7/MMBtu range. On the west coast, San Onofre Nuclear Generating Station (SONGS) #3's refueling outage created higher demand for natural gas fired generation within southern California, resulting in considerably higher prices for natural gas. Figures 2.4 and 2.5 depict weekly average prices and storage volumes, respectively.

Figure 2.4 Weekly Average Daily Natural Gas Prices

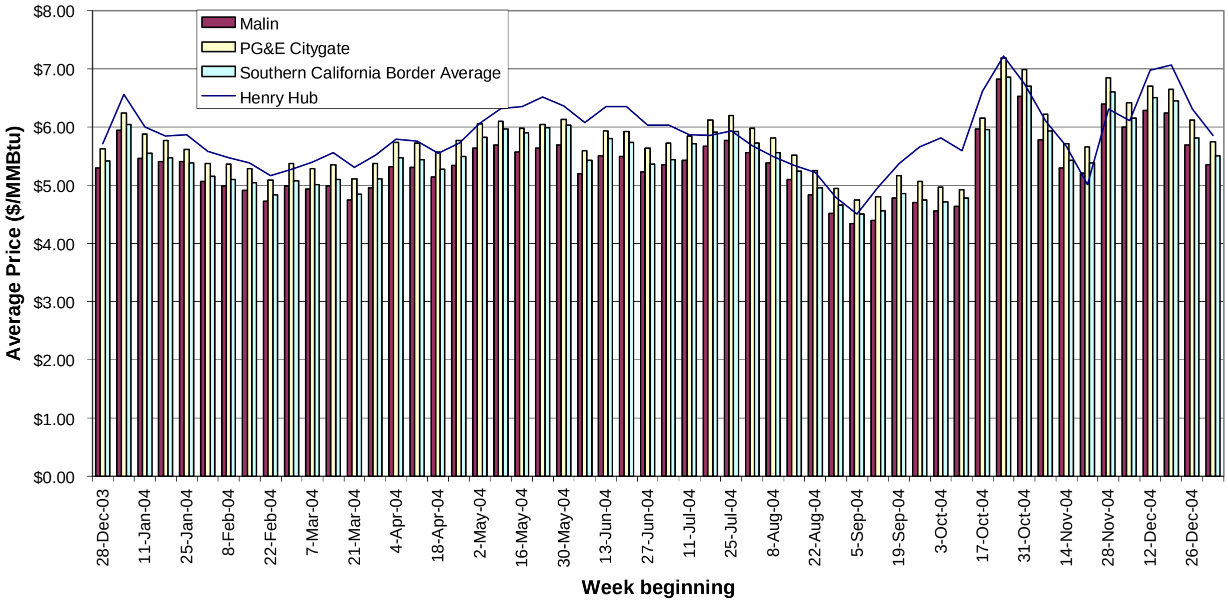
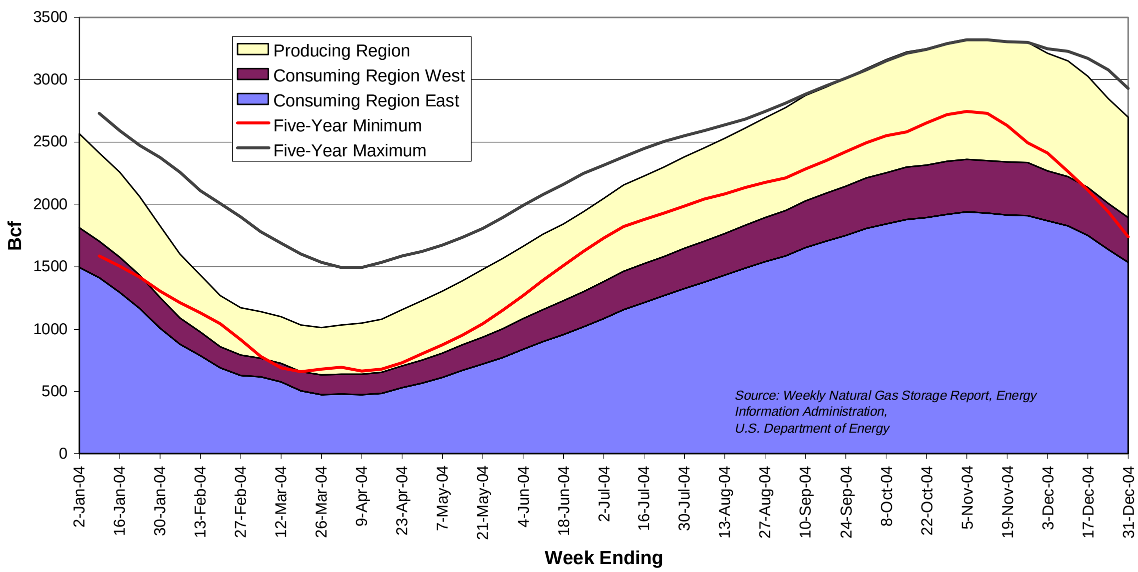


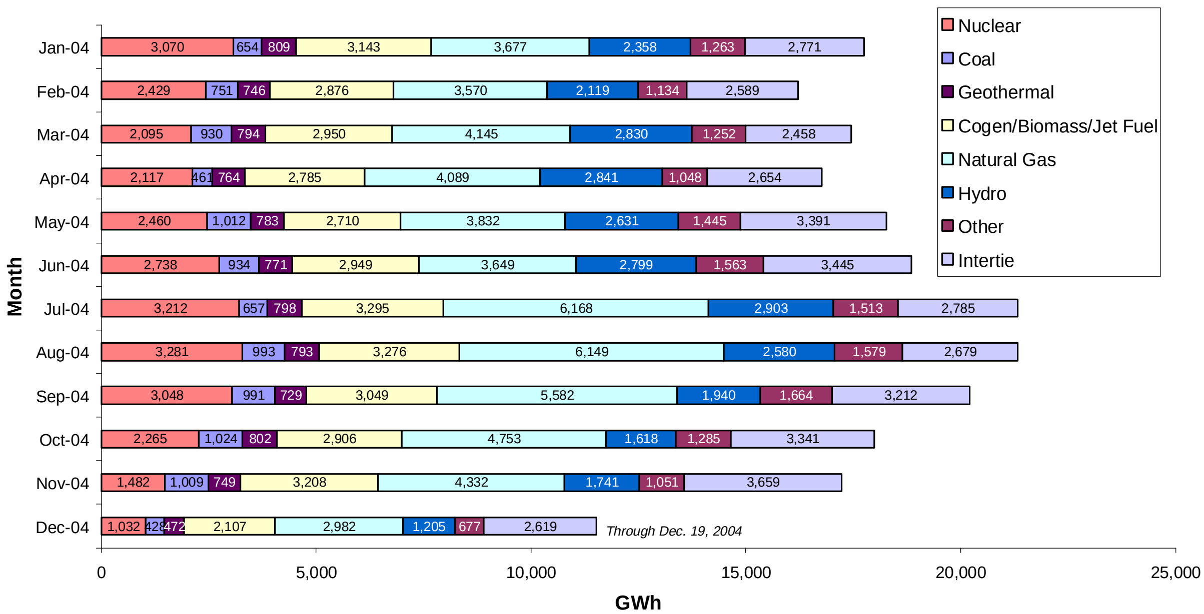
Figure 2.5 Weekly Natural Gas Storage



2.1.2.3.2 Generation by Fuel

Baseload generation sources such as nuclear, geothermal, cogeneration, and coal facilities, provided for between 41 and 50 percent of load each month. Between 12 and 23 percent of load was met by imports. The remaining 34 to 43 percent of load was provided by a combination of natural gas fired facilities and hydroelectric power. As load increased, natural gas plants provided for more of that load. During February through April and October through December, the amount of nuclear generation was sharply decreased due to the planned outages of SONGS #2 in February and March and the outages of SONGS #3 and Diablo Canyon #2 in the third quarter of 2004.

Figure 2.6 2004 Average Monthly Energy Percentage by Fuel Type



2.1.2.3.3 Outages

Generation availability was again high in 2004. As shown in Figure 2.7, 2004 monthly combined forced and planned outages were similar to 2003 levels with the exception of October and November when two nuclear units were out for refueling in 2004. The forced outage rate, the annual average percentage of generation out due to unplanned reasons, dropped slightly in 2004 from 2003 levels remaining near 4 percent as shown in Figure 2.9. Outages in 2004 displayed their usual seasonal pattern with planned maintenance and must-offer waiver approvals rising in the off-peak periods, and declining during the peak-load summer season.

Diablo Canyon #1 nuclear generating station was out for refueling between March 25 and the middle of June, Diablo Canyon #2 refueled between late October and the middle of December. The SONGS #2 refueled from the middle of February to the middle of April, and SONGS #3 went on an extended outage from the end of September to the end of December. Outages at either one of the SONGS units exacerbate the congestion at the Miguel substation. Figure 2.8 shows average load levels compared to the weekly average forced, planned, and units out on must-offer waivers for 2004.

Figure 2.7 2002 through 2004 Monthly Average Scheduled and Forced Outages

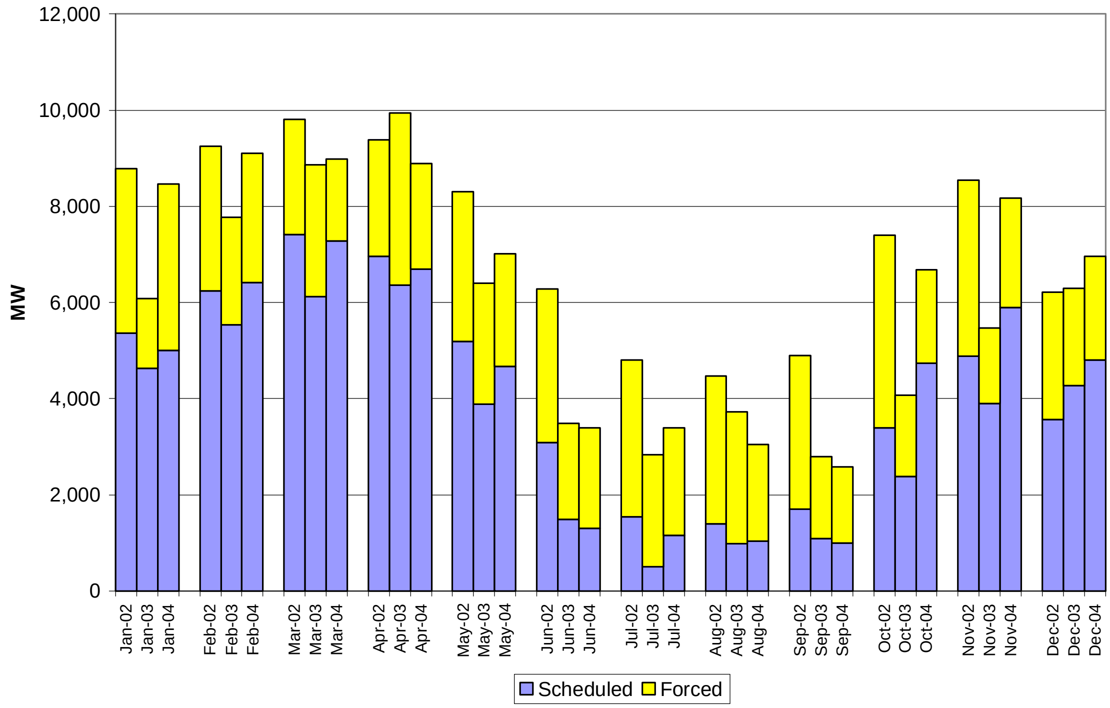


Figure 2.8 2004 Weekly Average Outage Levels

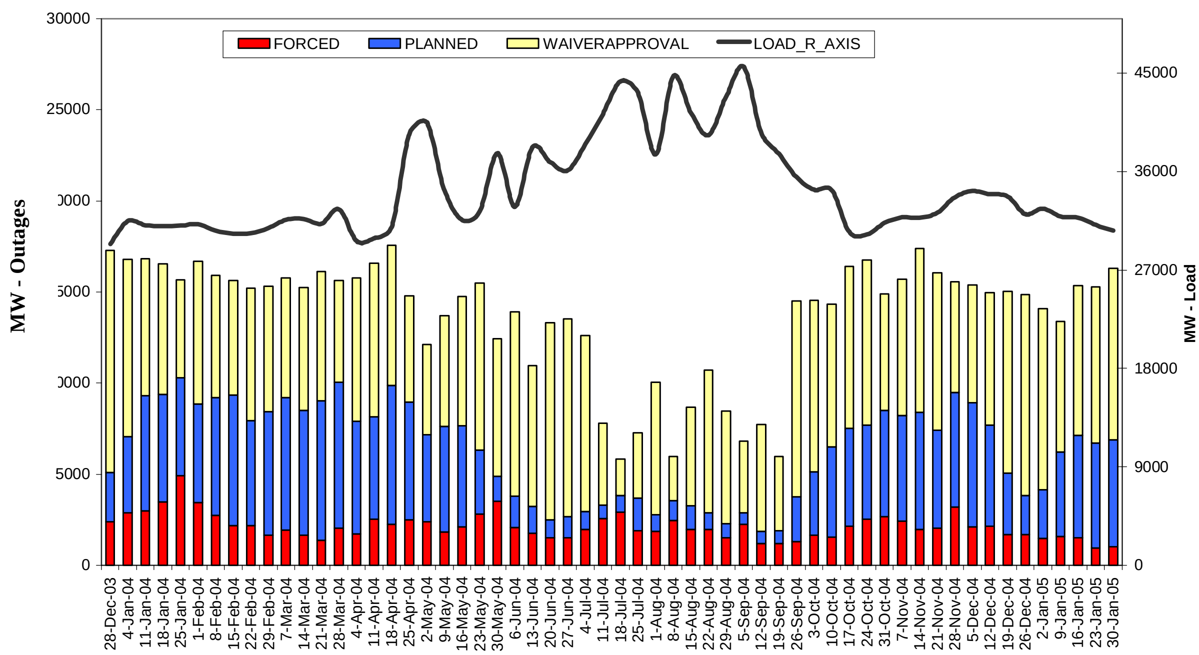
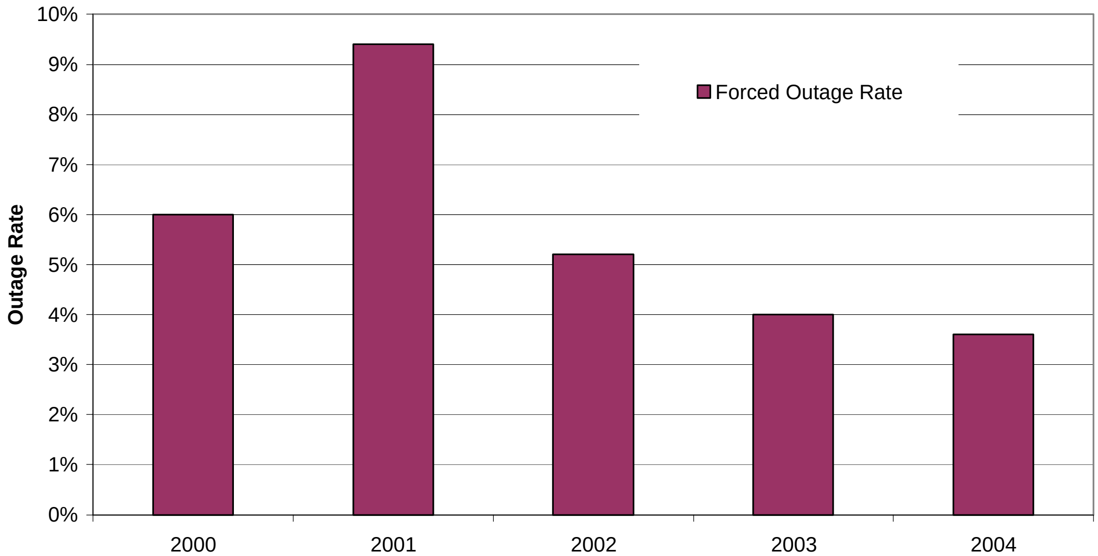


Figure 2.9 2000 through 2004 Forced Outage Rates



2.2 Total Wholesale Energy and Ancillary Services Costs

Since 1999, the CAISO has reported a wholesale energy cost index. The index 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 incremental energy costs, and ancillary service reserve costs. In 2004, we estimate the total cost to be $11.8 billion, compared to $10.8 billion in 2003.[3] We can attribute most of this increase to higher natural gas prices. This index does not include the CAISO and regulatory activity contributions to costs, which have also increased. These are shown later in the All-In Cost Index. Reliability must-run (RMR) and minimum load cost compensation costs (MLCC) have become more significant in recent years. Including these costs in the total wholesale energy and ancillary services costs increases the annual totals for 2002 through 2004 by $434, $615, and $937 million respectively. Including these costs results in total costs for 2002 through 2004 of $10.5, $11.4, and $12.8 billion respectively as shown in figure E.1. The following tables show the Wholesale Energy Cost Index by month (excluding RMR and MLCC) for 2004, and annual summaries from 1998 through 2004.

[3] This Annual Report uses an improved methodology to estimate unknown bilaterally contracted costs in 2003 and 2004. As a result, the 2003 cost total reported here differs from that reported in the 2003 Annual Report.

Table 2.3 Monthly Wholesale Energy Market Cost Index for 2004 and previous years

	ISO load	Forward costs (MM$)	RT Costs (MM$)	AS Costs ($MM)	Total Costs of Energy ($MM)	Total Costs of Energy and A/S ($MM)	Avg Cost of Energy ($/MWh)	AS Cost ($/MWh load)	AS % Energy Cost	Avg Cost of Energy & AS
Jan-04	18,757	$ 863	$ 2	$ 12	$ 865	$ 878	$ 46.79	$ 0.65	1.4%	$ 47.44
Feb-04	17,316	$ 813	$ 7	$ 11	$ 820	$ 831	$ 47.99	$ 0.66	1.4%	$ 48.66
Mar-04	18,902	$ 857	$ 15	$ 15	$ 872	$ 887	$ 46.92	$ 0.79	1.6%	$ 47.70
Apr-04	18,500	$ 805	$ 13	$ 12	$ 818	$ 830	$ 44.89	$ 0.67	1.5%	$ 45.56
May-04	20,101	$ 946	$ 11	$ 16	$ 957	$ 972	$ 48.36	$ 0.77	1.6%	$ 49.14
Jun-04	20,647	$ 941	$ 1	$ 18	$ 942	$ 960	$ 46.51	$ 0.87	1.8%	$ 47.38
Jul-04	23,198	$ 1,105	$ 15	$ 20	$ 1,120	$ 1,140	$ 49.15	$ 0.87	1.7%	$ 50.02
Aug-04	22,988	$ 1,103	$ 28	$ 22	$ 1,131	$ 1,152	$ 50.11	$ 0.94	1.8%	$ 51.05
Sep-04	21,658	$ 1,036	$ 20	$ 13	$ 1,056	$ 1,069	$ 49.35	$ 0.59	1.2%	$ 49.95
Oct-04	19,413	$ 962	$ 58	$ 20	$ 1,021	$ 1,041	$ 53.61	$ 1.04	1.9%	$ 54.65
Nov-04	18,432	$ 970	$ 26	$ 13	$ 995	$ 1,008	$ 54.68	$ 0.69	1.2%	$ 55.37
Dec-04	19,876	$ 1,054	$ 15	$ 13	$ 1,068	$ 1,081	$ 54.38	$ 0.64	1.2%	$ 55.01
Total 2004	239,788	$ 11,455	$ 209	$ 184	$ 11,665	$ 11,849				
Avg 2004	19,982	$ 955	$ 17	$ 15	$ 972	$ 78.32	$ 48.65	$ 0.77	1.6%	$ 49.41
Total 2003	230,668	$ 10,454	$ 173	$ 199	$ 10,626	$ 10,826				
Avg 2003	19,222	$ 981	$ 14	$ 17	$ 995	$ 1,012.08	$ 69.62	$ 0.86	1.6%	$ 52.70
Total 2002	232,011	$ 9,802	$ 99	$ 165	$ 9,900	$ 10,065				
Avg 2002	19,334	$ 817	$ 8	$ 14	$ 825	$ 838.77	$ 42.73	$ 0.70	1.7%	$ 43.38
Total 2001	227,024	$ 21,248	$ 4,162	$ 1,346	$ 25,410	$ 26,756				
Avg 2001	18,919	$ 1,771	$ 347	$ 112	$ 2,117	$ 2,229.67	$ 114.63	$ 6.07	5.3%	$ 117.86
Total 2000	237,543	$ 22,890	$ 2,877	$ 1,720	$ 25,373	$ 27,083				
Avg 2000	19,795	$ 1,907	$ 240	$ 143	$ 2,114	$ 2,256.89	$ 106.81	$ 7.24	6.8%	$ 114.01
Total 1999	227,533	$ 6,848	$ 180	$ 404	$ 7,028	$ 7,432				
Avg 1999	18,961	$ 571	$ 15	$ 34	$ 586	$ 619.33	$ 30.89	$ 1.78	5.7%	$ 32.66
1998 (9mo)	169,239	$ 4,704	$ 209	$ 638	$ 4,913	$ 5,551				
Avg 1998	18,804	$ 523	$ 23	$ 71	$ 546	$ 616.79	$ 29.03	$ 3.77	13.0%	$ 32.80

Notes:

1998-2000:

Forward costs include estimated 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.

2001 and 2002:

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

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

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 and 2004:

Forward energy costs 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 Powerdex hour-ahead prices.

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

All years:

*** Including ISO purchase and self-provided A/S priced at corresponding A/S market price for each hour, less Replacement Reserve refund.

2.2.1 All-In Price Index

The "All-In Price Index" is a standardized metric developed by the FERC Office of Market Oversight and Investigation and several ISO market monitoring units, to provide, to the extent possible, an indicator of wholesale energy costs that can be compared across electricity markets in several regions of the United States. The index includes adjustments to facilitate the comparison of providers with disparate features in an "apples-to-apples" manner. Thus, the All-In Price Index is not equivalent to the Wholesale Energy Cost Index discussed in section 2.2. The All-In Price index is not an estimate of total wholesale market costs; rather, it is a simplified index that shows the relative cost contribution of various market services. Extreme care should be taken when comparing the All-In Price Index to other indices published by the Department of Market Analysis or by other entities. The All-In Price Index contains the average cost contributions of each of the following per megawatt-hour delivered to load:

- An estimate of forward energy costs, plus
- Real-time energy incremental costs, less
- Real-time decremental costs (negative), plus
- Minimum-load compensation[4] to units held on pursuant to the "Must-Offer" waiver denial process, plus
- Out-of-sequence energy costs, plus
- RMR costs, plus
- Market costs of ancillary services (with self-provided services estimated at market costs), plus
- Grid management charges for all services.

The CAISO's All-In Price Index was $53.46/MWh in 2004, compared to $49.20/MWh in 2003 and $45.07/MWh in 2002 using equivalent methodologies.[5] The increase of approximately 8.7 percent since 2003 is due largely to the increases in the estimate of forward costs to $46.64/MWh in 2004, from $44.20/MWh in 2003, and increases in reliability service costs, from growth in costs for generation committed pursuant to RMR agreements and the Must-Offer Obligation.

This methodology differs from that used to calculate the Total Wholesale Cost Index in that real-time prices are itemized into incremental and decremental components and it includes an out-of-sequence component (comprising redispatch premium costs in excess of market costs).

The following figure and table provide views of all-in costs and prices. Table 2.4 shows the All-In Price Index for 2002 through 2004 by contributing factor. Figure 2.10 shows a side-by-side comparison of the All-In Prices for 2002 through 2004.

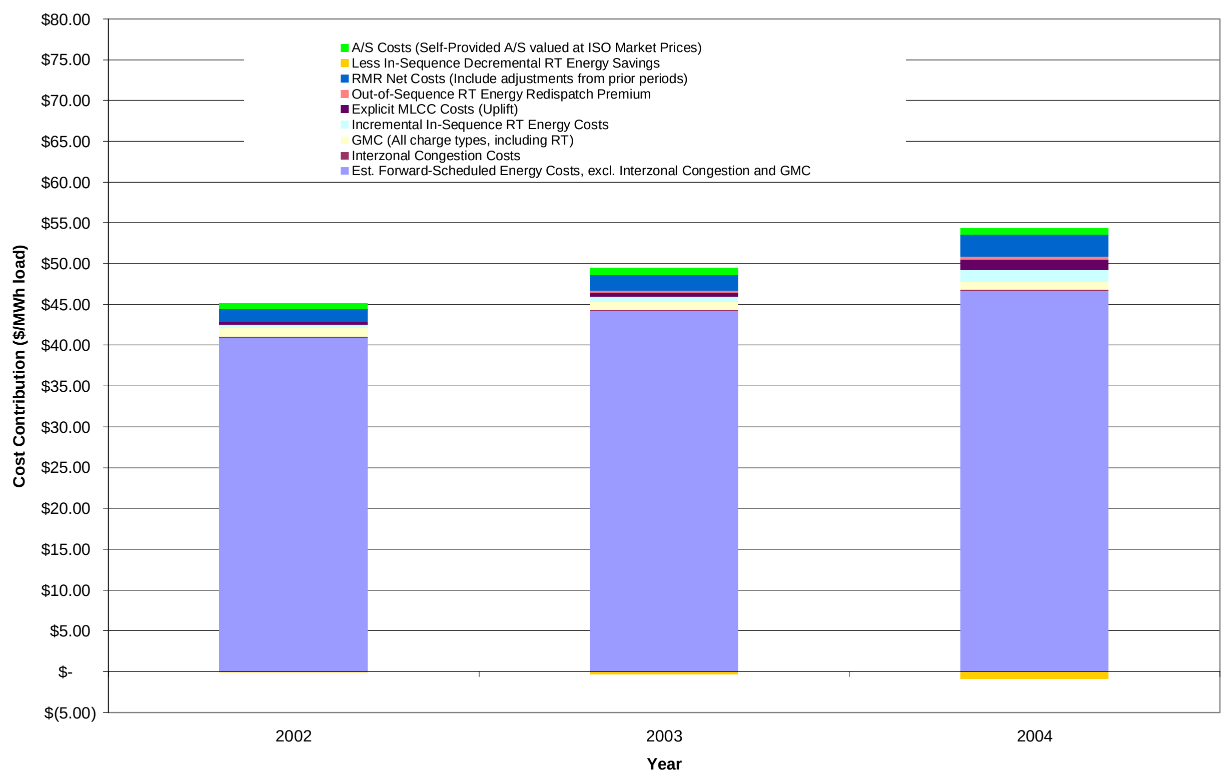
4 Minimum Load Compensation Costs (MLCC) include start-up and no-load costs paid to generation units that are denied must-offer waivers.

5 The same improvement in the estimation of unknown bilateral forward costs used in the Energy Cost Index was also used in the All-In Price Index. Thus, 2003 numbers differ from those reported in the 2003 Annual Report.

Table 2.4 All-In Price Index: 2002-2004

		2002		2003		2004		Change '03-'04
Est. Forward-Scheduled Energy Costs, excl. Interzonal Congestion and GMC	$	40.92	$	44.20	$	46.64	$	2.44
Interzonal Congestion Costs	$	0.18	$	0.12	$	0.23	$	0.12
GMC (All charge types, including RT)	$	1.00	$	1.00	$	0.90	$	(0.10)
Incremental In-Sequence RT Energy Costs	$	0.49	$	0.63	$	1.47	$	0.84
Explicit MLCC Costs (Uplift)	$	0.26	$	0.54	$	1.21	$	0.66
Out-of-Sequence RT Energy Redispatch Premium	$	0.02	$	0.19	$	0.43	$	0.24
RMR Net Costs (Include adjustments from prior periods)	$	1.60	$	1.95	$	2.67	$	0.72
Less In-Sequence Decremental RT Energy Savings	$	(0.08)	$	(0.29)	$	(0.86)	$	(0.57)
Total Energy Costs	$	44.39	$	48.34	$	52.69	$	4.36
A/S Costs (Self-Provided A/S valued at ISO Market Prices)	$	0.68	$	0.86	$	0.77	$	(0.09)
ISO-related Costs (Transmission, Reliability, Grid Mgmt.)	$	4.15	$	5.00	$	6.82	$	1.83
Total Costs of Energy and A/S ($/MWh load)	**$**	**45.07**	**$**	**49.20**	**$**	**53.46**	**$**	**4.26**
A/S Costs % of All-In Price Index		1.5%		1.8%		1.4%		-2.2%

Figure 2.10 Annual all-in prices



2.3 Short-term Forward Energy Market Competitiveness

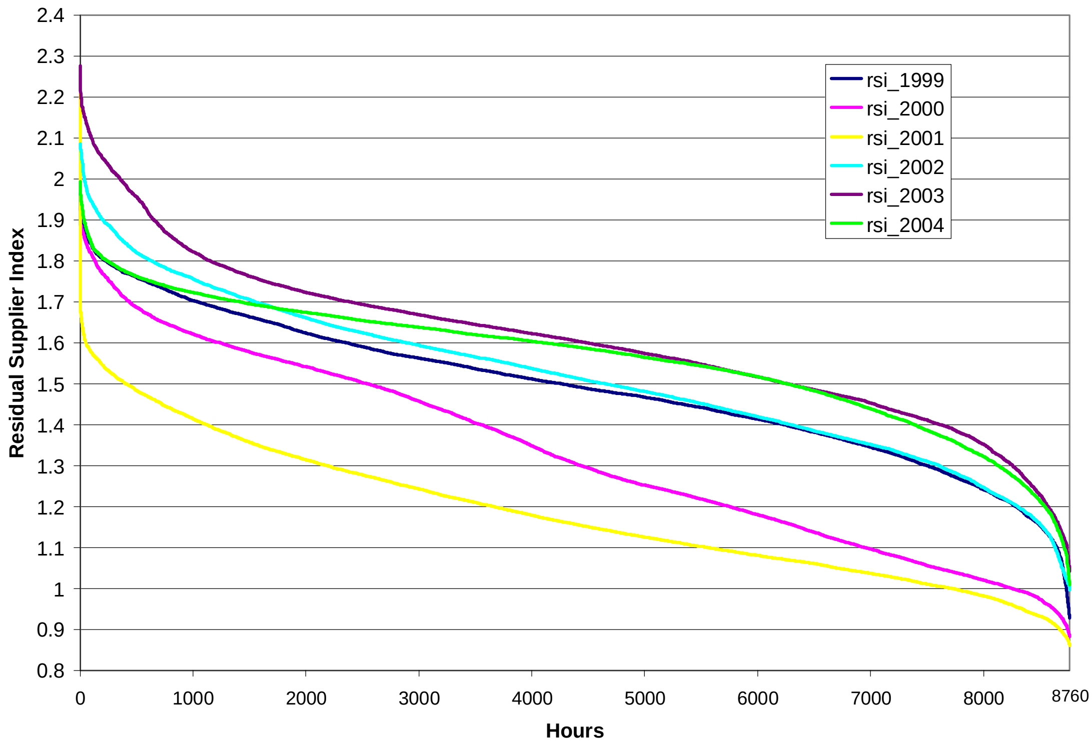
2.3.1 Structural Measures of Whether Suppliers are Pivotal in Setting Prices: Residual Supplier Index

The residual supplier index (RSI) is an index used to measure the market structure rather than market outcomes. This index measures the degree to which suppliers are pivotal in setting market prices. Specifically, the RSI measures the degree that the largest supplier is "pivotal" in meeting demand. The largest supplier is pivotal if the total demand cannot be met absent the supplier's capacity. Such a case would translate to an RSI value less than 1.0. When the largest suppliers are pivotal (an RSI value less than 1.0), they are capable of exercising market power. The closer the RSI gets to 1.0, the greater the potential for a large supplier to exercise unilateral market power through raising their bids or withholding generation. In general, higher RSI values correspond to greater market competitiveness.

The RSI indices in 2004 were nearly as high as in 2003, which were the highest of the past five years. Using an RSI level of 1.1 to compare between years,[6] in 2004 the RSI levels were less than 1.1 in less than 0.55 percent of the hours (only 48 hours out of 8760). In contrast, there were 3,215 hours or 37 percent of the hours in 2001 where the RSI was less than 1.1. These results indicate that the California markets in 2004 were again significantly more competitive than in 2001 and 2000 as a result of the addition of new generation and high levels of net imports over the period. The RSI levels are consistent with the market outcomes and short-term energy market price-cost mark-ups we observed in 2004. The significant amount of long-term contracts entered into in 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. Taking the account of the long-term contracts would likely raise the RSI values even higher. The RSI analysis shows that the underlying physical infrastructure was much more favorable for competitive market outcomes in the period of 2002 through 2004 than in 2001 as reflected by the higher RSI levels. Figure 2.11 compares RSI duration curves for the past five years.

6 The 1.1 RSI level was chosen simply as it is close to 1.0 which would indicate a situation in which the potential to exercise market power is high.

Figure 2.11 Hourly Residual Supplier Index 1999-2004



2.3.2 Short-term Energy Price-to-Cost Mark-up Analysis[7]

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.

Previous issues of the Department of Market Analysis Annual Report on Market Issues and Performance 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 bi-lateral forward contracts to prices from Department of Water Resources' California Energy Resources Scheduler (CERS) energy procurement deals. CAISO has updated its methodology 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, CAISO makes use of hourly short-term forward price data via purchased indices from Powerdex,[8] an independent energy information company. Powerdex surveys buyers and sellers of energy at key Western hubs and compiles hourly prices.

[7] Short-term energy is defined as forward purchased energy purchased within 24 hours of real-time operation.
[8] http://www.hourlyindexes.com - P.O. Box 710886, Houston, TX, 77071

The CAISO continues to utilize a “single resource portfolio” methodology to meet the objective of developing a competitive benchmark for short-term bilateral energy markets. The methodology depends on several assumptions: every asset in the portfolio bids competitively, all bids are at marginal cost, and the portfolio clears against the total of actual historical hour-ahead generation schedules in each hour of benchmark development.

Additional conditions were necessary to develop the competitive hour-ahead bilateral market clearing price benchmark. All of the resources in the portfolio are assigned unit commitment levels based on historical hour-ahead schedules. Hydroelectric units in the portfolio are optimally dispatched to reflect total metered output for the given week in history. Pumped storage generation units optimally pump and generate within the bounds of storage and release constraints as well as pumping efficiency. Resources in the cogeneration, renewable and QF classes, in addition to resources with unknown variable costs, were forced to operate in direct accordance with their forward energy schedules. California imports are modeled to flow economically, bound by hourly intertie availability, and are priced at historical Powerdex hub price levels for the California-Oregon Border (COB) and Palo Verde (PV).

The CAISO market model utilizes PLEXOS for Power Systems™ as the market simulation tool. PLEXOS employs a linear programming based production cost model, which allows for co-optimization with ancillary service markets. PLEXOS for Power Systems™ is produced by Drayton Analytics, Pty Ltd.[9] The majority of the data for the model is sourced from CAISO market operations records. When variable cost information is not available through operations data, the CAISO attempts to obtain it from data purchased from Henwood Energy Services, Inc.[10] Henwood is also the source for the pumped storage reservoir volumes and pump efficiency data employed in the model.

For calendar year 2004, the CAISO observed short-term mark-ups ranging from 1.2 to 22.5 percent, a slight increase over the prior year. Figures 2.12 and 2.13 summarize competitiveness in the short-term forward energy markets. SP15 posted seven months with mark-ups greater than 10 percent while NP15 logged five such months. Months with the greatest mark-ups were September and October, corresponding to tighter supplies, given the high end of summer load levels and the Pacific DC Intertie outage, and some uncertainty on the part of market participants, given changes in the CAISO real-time market structure. On the whole, 2004 short-term forward markets functioned effectively, leading largely to competitive pricing in both the NP15 and SP15 regions. The CAISO continues to harbor concerns over price mitigation issues. Given the upward trend in mark-ups through 2004 and the ability of suppliers to sharply increase these in a short period of time, regulators have a basis on which to carefully consider the extension of additional mitigation tools.

[9] http://www.draytonanalytics.com - PO Box 13, North Adelaide, SA 5006, Adelaide, Australia
[10] http://www.henwoodenergy.com - 2379 Gateway Oaks Dr., Suite 200, Sacramento, CA, 95833

Figure 2.12 2004 Short-term Forward Market Index – NP15

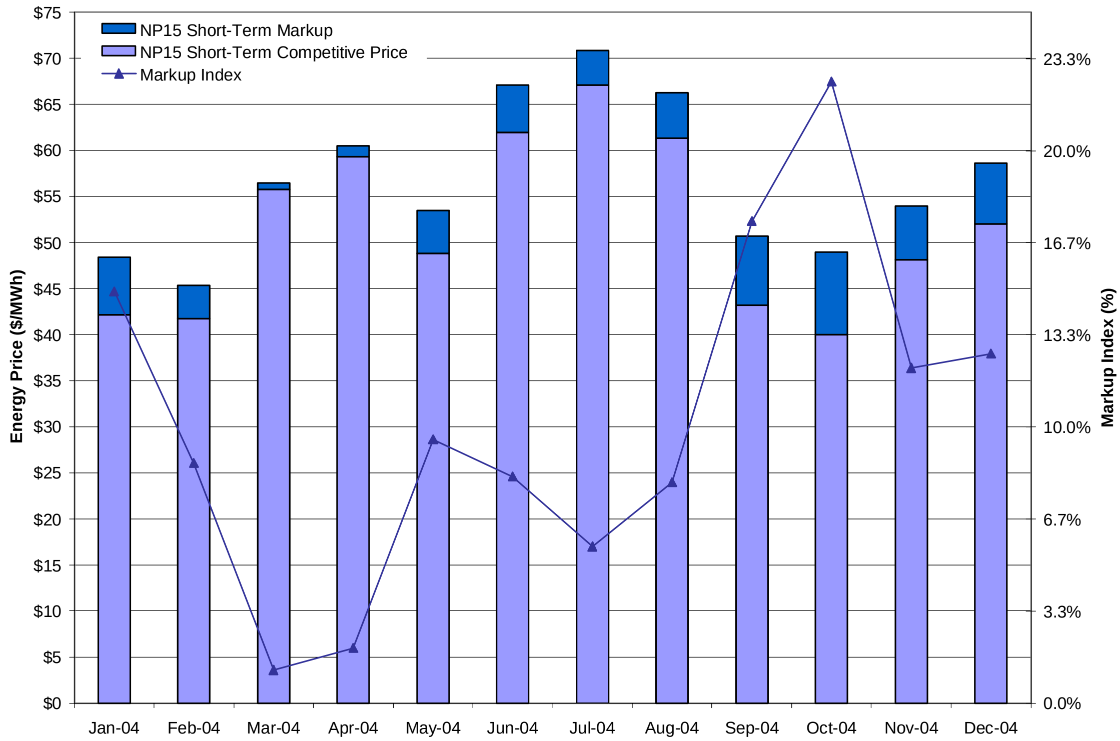
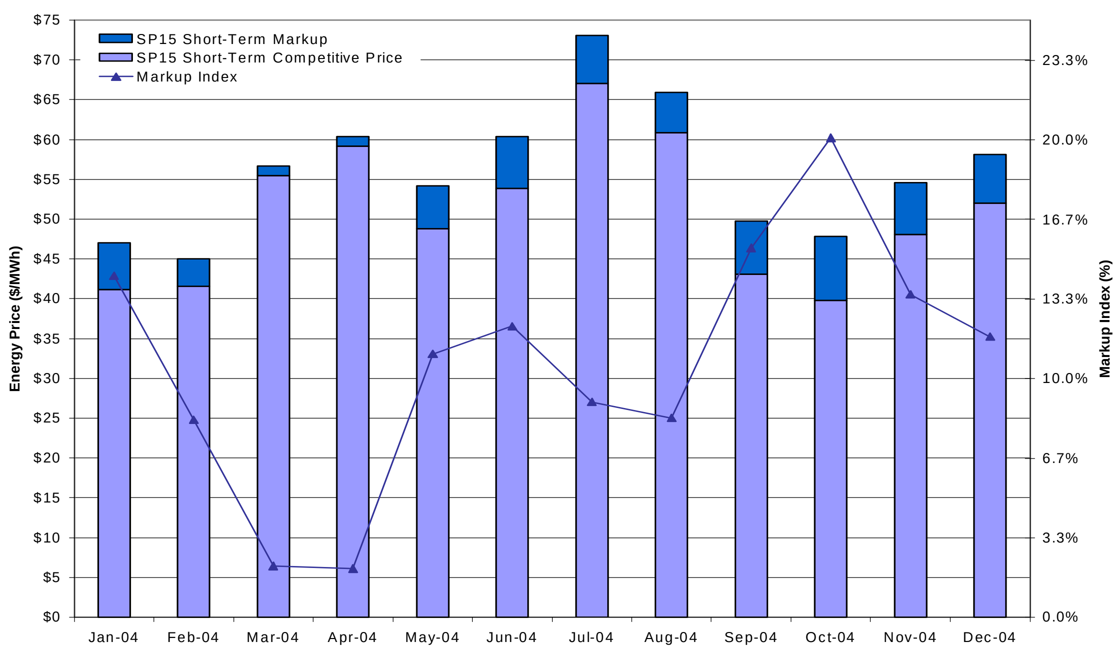


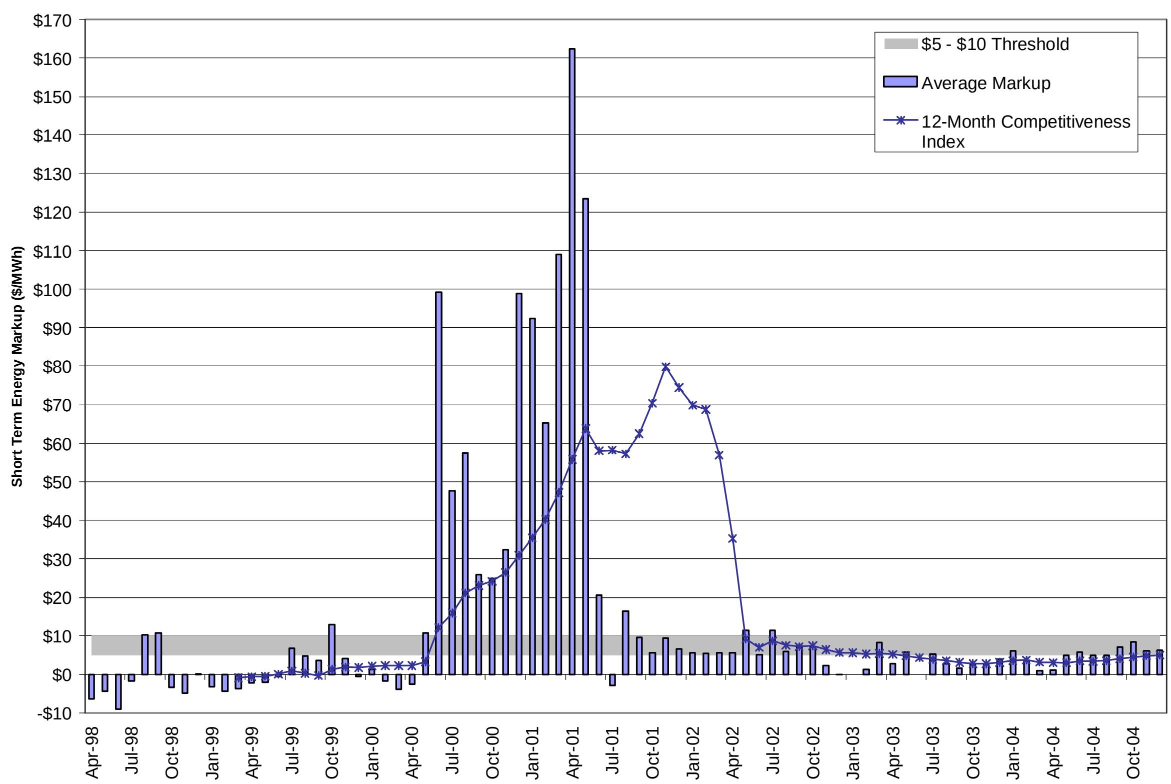
Figure 2.13 2004 Short-term Forward Market Index – SP15



2.3.3 Twelve-Month Competitiveness Index

The CAISO employs several indices during market competitiveness assessments. The index in Figure 2.14 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 approximated competitive prices. 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.

Figure 2.14 Twelve-Month Competitiveness Index Through December 2004



2.4 Real-time Market Performance Indices

2.4.1 Real-time Market Price to Cost Mark-up

DMA has developed a real-time price to cost mark-up index designed to measure market performance in the real-time market. This index compares real-time market prices to estimates of real-time system marginal costs. The analysis only includes resources that were actually dispatched for real-time energy by the CAISO, therefore it excludes resources or certain portions of resources that were unable to respond to dispatch instructions for reasons such as physical operating constraints.[11] While an index based upon the small volume of transactions in the real-time market is not the preferred method of measuring the performance of the short-term energy market in California, it provides a measure of market performance trends for the imbalance energy market.

The real-time competitive market clearing price 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 obligations.

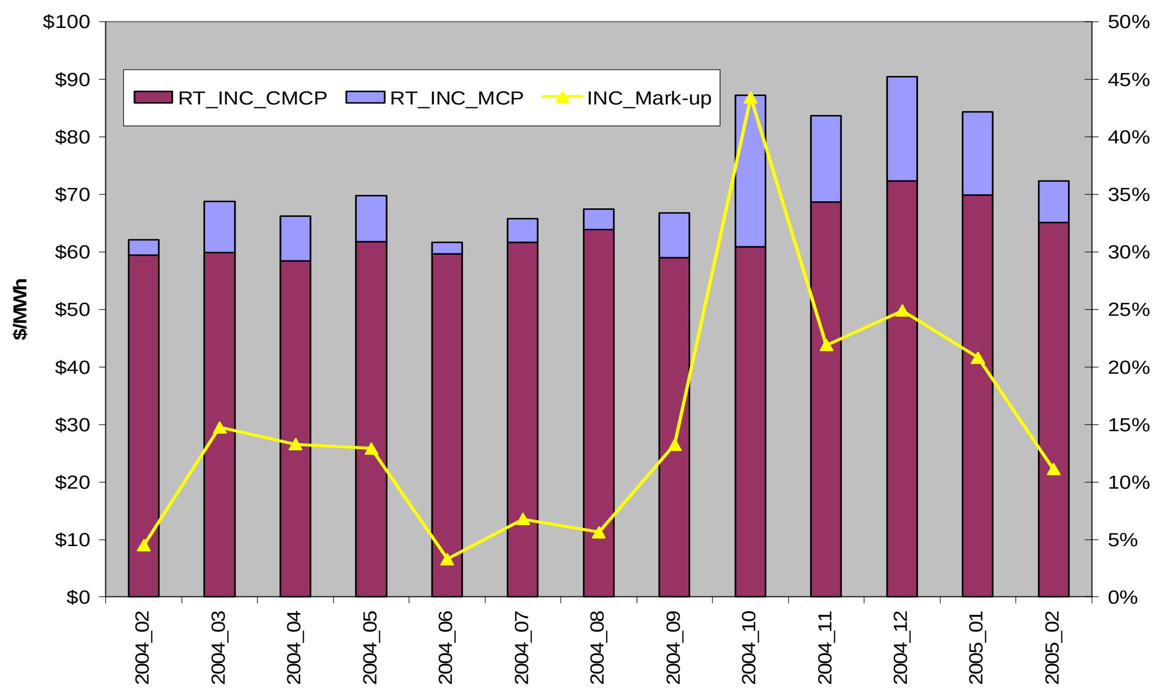
While we would not expect actual prices to equate to the competitive baseline prices, the index provides some insight into trends of real-time market performance. For more than two years, we have observed average monthly mark-ups that have averaged less than 20 percent, indicating a fairly healthy real-time energy market which we attribute primarily to the low (or often negative) imbalance energy demand resulting from the limited underscheduling that has occurred since 2001.

The low mark-ups trend that had been observed ended briefly in October 2004 with the implementation of the new real-time market application software (RTMA). RTMA was implemented as part of the CAISO's market redesign and technology upgrade (MRTU). The higher mark-up over competitive baseline prices was the result of several factors. First, RTMA takes into account generation unit operating constraints in determining real-time market dispatches. We expect this change to make the market more efficient over time but initially the new systems encountered some problems related to generation units' operating data that was not accurately input into the RTMA. For example, initially when the real-time market operation was switched over to the RTMA, several units had default ramp rates set at minimum ramping levels which caused the RTMA software to dispatch deep into the bid stack to meet imbalance energy requirements. This resulted in actual prices that were significantly higher than competitive baseline prices, which are based on the units' actual ramping capabilities. Similarly, certain reliability must run units (RMR) had the same maximum and minimum ramp rates stored in the CAISO's database, restricting these units from bidding in variable ramp rates with their supplemental real-time energy bids. To compensate, these units used pricing as a proxy for their ramping restrictions, which resulted in inefficient pricing. The CAISO has made great progress in addressing RTMA issues. This has resulted in significant improvements to real-time market performance.

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

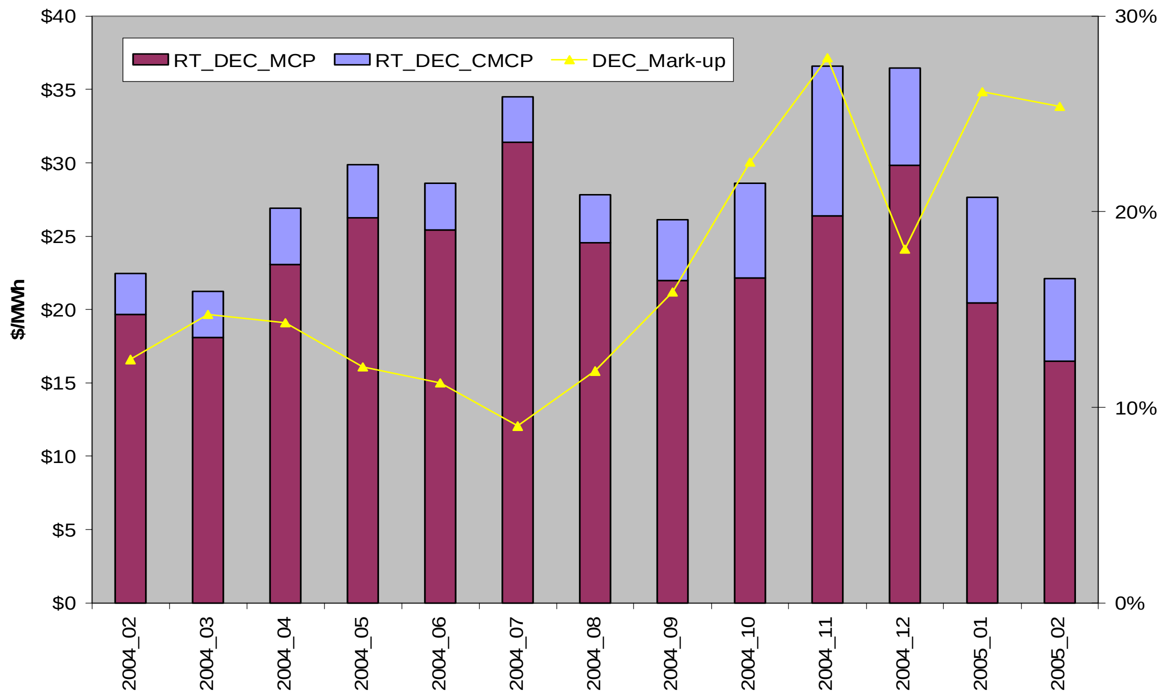
Figure 2.15 shows the monthly average mark-up above competitive baseline prices for incremental real-time energy dispatched in 2004. As shown in the figure, the downward mark-up trend ended in October 2004 with the implementation of the new RTMA systems but has since trended downward to levels previously observed prior to RTMA implementation as issues associated with the new real-time software have been addressed. Similarly, Figure 2.16 shows the mark-up below the competitive baseline decremental price for decremental dispatch intervals. Higher decremental dispatch volumes have resulted in slightly higher mark-ups for decremental dispatches. They averaged between 10 and 20 percent before increasing to nearly 30 percent after the implementation of RTMA in October 2004. Software tuning continues on the RTMA and we expect mark-ups to continue their downward trend as real-time markets continue to be competitive due to forward scheduling of energy that is near actual load levels. This has resulted in low demand for real-time energy outside of the morning and evening load ramping periods.

Figure 2.15 Real-time Incremental Energy Mark-up above Competitive Baseline Price[12]



[12] Generating unit marginal costs are based on operating information supplied to the CAISO and locational fuel costs. Incremental Reference level bid values calculated by Potomac Economic as part of the CAISO market power mitigation measures are used when cost information is not available.

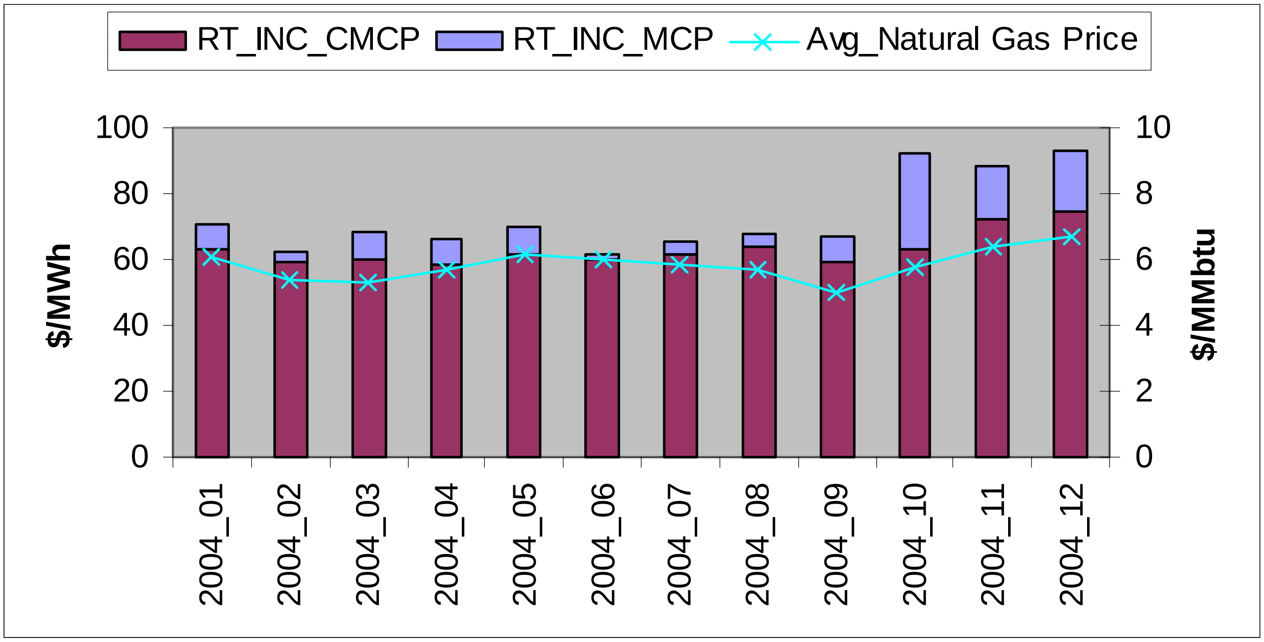
Figure 2.16 Real-time Decremental Energy Mark-up below Competitive Baseline Price[13]



As discussed above, we calculate the CMCP by replacing bid prices for dispatched units by cost information for dispatched thermal units and reference prices if such cost information is not available. The CMCP closely follows the trend in gas prices. As shown in Figure 2.17 below, April, May, and June have more hydro generation so the monthly average CMCP is 10 times weighted gas prices, while in other months the CMCP is roughly 11 times the corresponding natural gas price.

13 Generating unit marginal costs are based on operating information supplied to the CAISO and locational fuel costs. Decremental Reference level bid values calculated by Potomac Economic as part of the CAISO market power mitigation measures are used when cost information is not available.

Figure 2.17 CMCP Relation to Natural Gas Prices



2.4.2 Real-Time Market Residual Supplier Index Analysis (RSI)

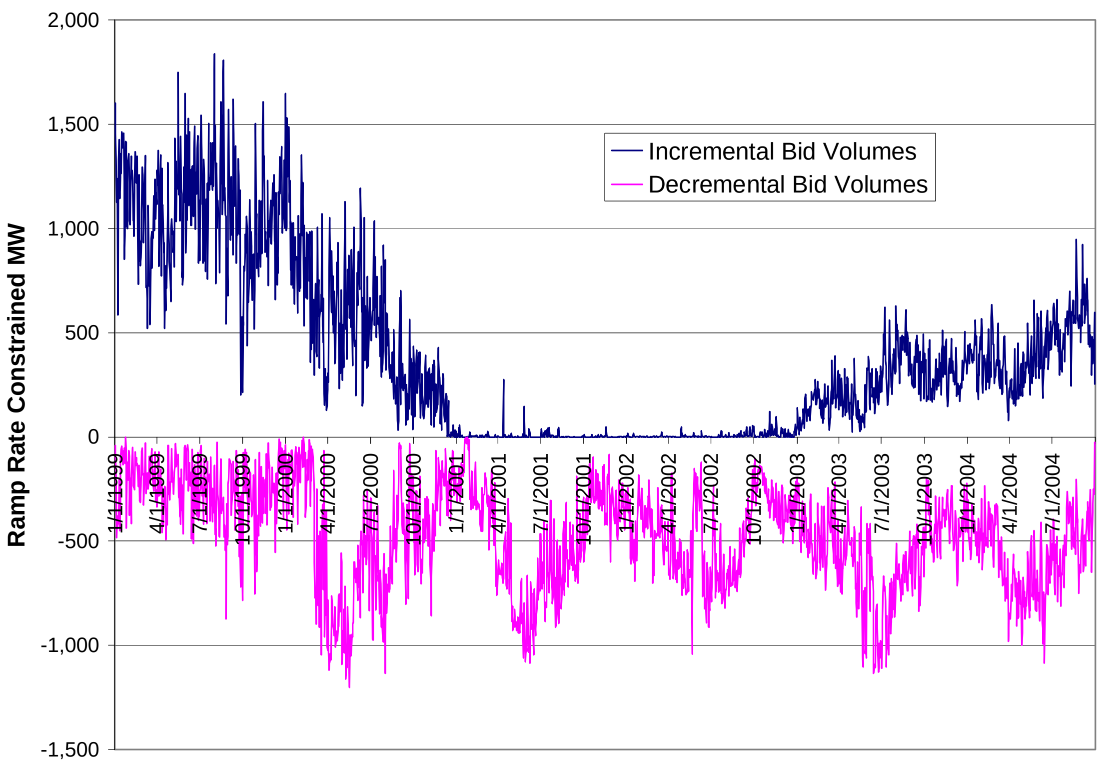
As mentioned above, the CAISO uses the residual supplier index (RSI) to measure the physical aspects of the market and the degree to which suppliers are pivotal in setting market prices. Figures 2.19 through 2.22 depict RSI duration curves and RSI relation to market clearing prices for both incremental and decremental real-time imbalance energy since RTMA became operational on October 1, 2004, through December 31, 2004, based on energy bids supplied to the CAISO real-time imbalance energy market.

Real-time market splits have a significant impact on real-time market competitiveness. CAISO operators often have to split the market between zones due to transmission constraints. For the majority of the time, the real-time market was not split between zones and the imbalance energy market encompassed the entire CAISO control area. Under this condition, supply conditions were better than the time when the market was zonally split between the NP15 and SP15 congestion zones. However, even under the no-splitting situation, RTMA was often forced to dispatch resources deep into the stack to meet imbalance energy requirements.

During periods of real-time market splits, imbalance conditions in NP15 seldom required incremental energy dispatches. This was unlike SP15, where incremental energy was often needed to meet imbalance energy demands. This resulted in more volatile incremental energy prices in SP15. The same phenomenon is true for decremental energy dispatches in NP15. During periods of market splits high demand for decremental energy in NP15 resulted in more volatile prices.

Figure 2.19, the RSI duration curve for real-time incremental imbalance energy, shows that when prices were set on a system wide basis, RSI levels were near or below 1.0 around 30 percent of the time. When transmission congestion between SP15 and NP15 required the real-time market to be split, the results were less favorable as incremental energy was needed in SP15 and must be met with fewer supply resources. During periods of market splits, RSI levels were near or below 1.0 in SP15 more than 50 percent of the time. Most of the low RSI values calculated occurred during periods of load ramping, which require a rapid increase in imbalance energy over a short period of time. This highlights the fact that in the real-time market, it is not a lack of physical generation resources available to meet imbalance requirements, but the lack of sufficient ramping capability of the set of resources available to meet imbalance needs that leads to the unfavorable competitive conditions during ramping periods. This is often the result of a deficiency of fast ramping hydro resources supplying ramping energy bids into the real-time market. Figure 2.18 below shows the daily energy bid into the real-time imbalance energy market by resources that have greater than 40 MW/minute ramping capability. As shown, the amount of quick ramping resources in the real-time bid stack declined dramatically in 2001 as a result of poor hydro conditions. These resources have been slow to return to the real-time market and are still well below 1999 levels. Load ramps are in turn met by a large number of slower ramping thermal generation resources that must be dispatched to meet the fast changing imbalance requirements.

Figure 2.18 Total Energy Bid into Real-time Market with Ramp Rate > 40 MW/min



As shown in Figure 2.20, there is a strong relationship between high real-time incremental market clearing prices and low RSI values. We expect this as lower RSI values indicate less competitive market conditions. Although the real-time energy markets throughout 2004 largely produced competitive outcomes, there were often short periods of time as described above when most of the available real-time energy supply offered to the CAISO had to be dispatched to meet imbalance energy requirements. During these periods, pivotal suppliers were present and price spikes often occurred.

Figure 2.19 RSI Duration Curve for Incremental Energy

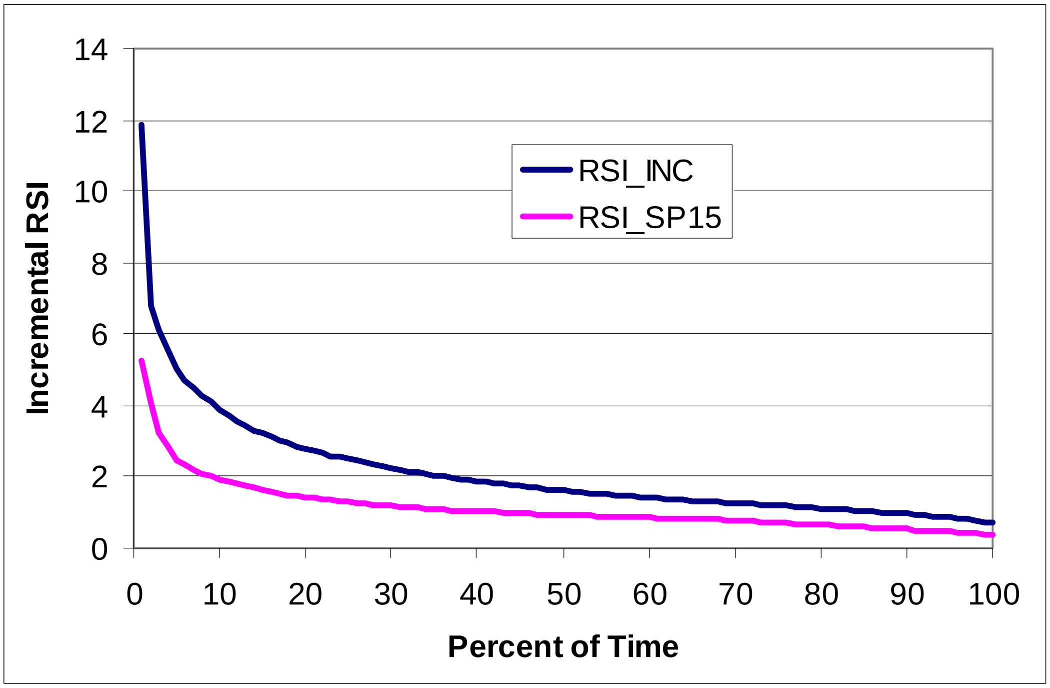
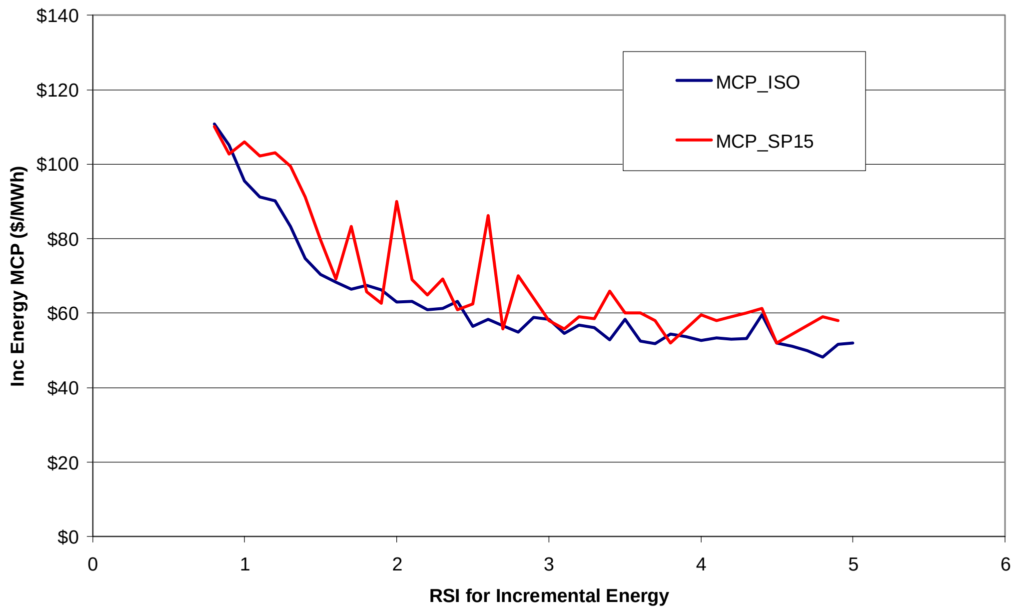


Figure 2.20 RSI Relationship to Real-time Incremental Market Clearing Prices



Figures 2.21 and 2.22 show the RSI relationships during decremental dispatch periods. As shown in Figure 2.21, the RSI for decremental dispatched was near or below 1.0 around 35 percent of the time. Low RSI values for decremental dispatches usually occurred during low load off-peak hours when real-time decremental supply is scarce due to units operating near or at minimum output levels. During these periods, decremental market clearing prices were often low as shown in Figure 2.22.

Figure 2.21 RSI Duration Curve for Decremental Energy

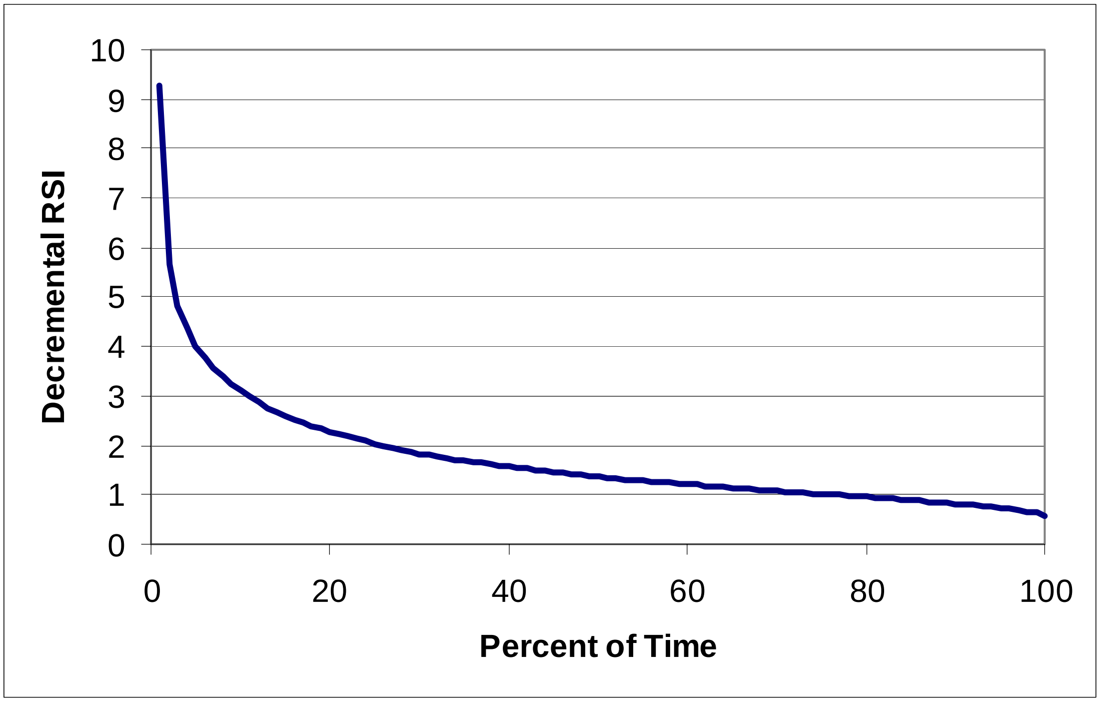
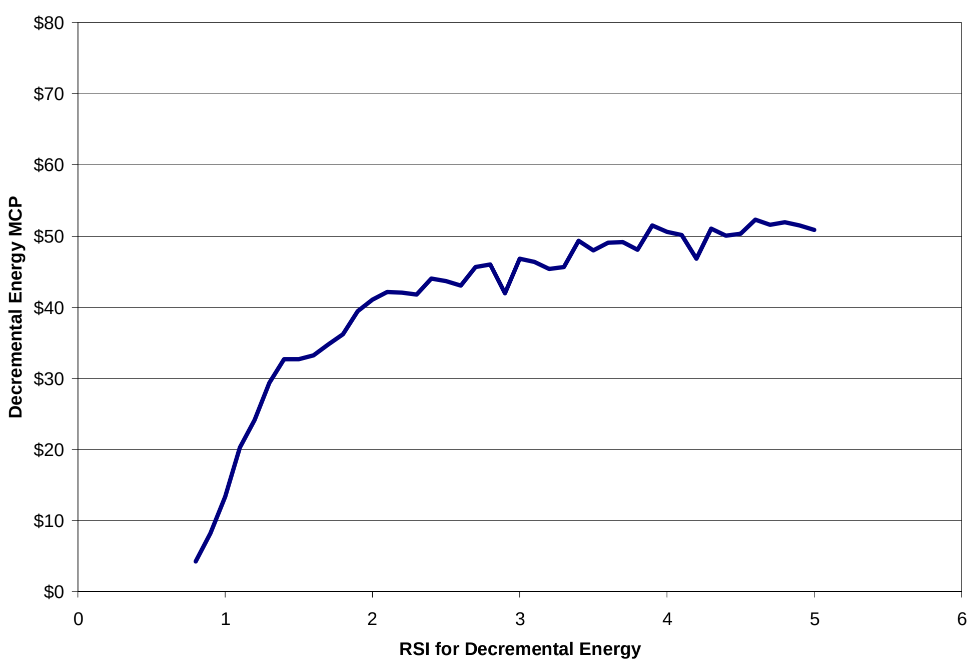


Figure 2.22 RSI Relationship to Real-time Decremental Market Clearing Prices



2.5 Net Revenue Analysis and Revenue Adequacy for New Generation

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

The majority of projects proposed in California and the WECC during the last several years have been gas-fired combined cycle plants of approximately 500 MW. This analysis is based on a typical 500 MW combined cycle unit and a typical 100 MW combustion turbine unit as defined in a 2003 California Energy Commission (CEC) study.[14] Tables 2.5 and 2.6 summarize the key generation unit assumptions for a typical new combined cycle unit and a typical new combustion turbine unit used in this analysis derived from the CEC study.

[14] "Competitive Cost of California Central Station Electricity Generation Technologies," California Energy Commission, Report # 100-03-001F, June 5, 2003, Appendices C and D.

Table 2.5 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 2.6 Analysis Assumptions: Typical New Combustion Turbine Unit

Maximum Capacity	100 MW
Minimum Operating Level	40 MW
Ramp Rate	6 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

Revenues were calculated for a hypothetical unit selling solely in the CAISO real-time imbalance energy and ancillary service markets to provide a benchmark for prices in the CAISO's markets.[15] As shown in Table 2.5, the CEC estimates that over a 20 year period, a new combined cycle unit would need to recover on average $90/kW-year or $90,000/MW-year in fixed costs to be profitable. Similarly, the CEC estimates the fixed cost recovery requirement for a new combustion turbine unit to be $78/kW-year or $78,000/MW-year as shown in Table 2.6. We ran a net revenue analysis for both the 2003 and 2004 calendar years. For a baseline, we assumed the generator was located in an unconstrained area and would self-commit when it was profitable to do so. Next, we estimated the additional revenue a combined cycle generator could have received under the must-offer commitment process had the generator located in a transmission constrained area within SP15. This additional CAISO commitment revenue is generated from the double energy payment made under the current must-offer rules and is noted as MLCC (minimum load cost compensation) in Table 2.7. Under the must-offer obligation rules, generators that are denied must-offer waiver obligations by the CAISO are compensated for their start-up and minimum load operation costs as well as paid the uninstructed energy price for the minimum load energy. This construct results in a double payment for the minimum load energy and significantly increases the net revenue a unit could earn in a constrained area.

The results show that in 2003, in the unconstrained area analysis, a combined cycle unit selling solely into the CAISO imbalance energy and ancillary service spinning reserve markets would have received a net revenue in the range of approximately $47 to $58/kW-year for NP15 and SP15 respectively. In 2004, the largely decremental imbalance energy market combined with higher operating costs resulted in lower net

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[15] The operational and scheduling assumptions used for each unit are summarized below:

1. We first determined an initial operating schedule based on real-time energy prices and the unit's marginal operating costs. The unit was scheduled up to full output when hourly prices exceed variable operating costs.
2. We modified the initial schedule by applying an algorithm to determine if it would be more economical to shut down the unit during hours when real-time 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 exceed real-time energy prices.
3. We applied a series of simplified ramping constraints to the unit's schedule to approximate the degree to which the unit would need to deviate from this schedule given the unit's ramp rate.
4. We included all startup costs associated with the simulated operating of the units in operating costs.
5. We calculated ancillary service revenues by assuming the unit could provide 50 MW of spinning reserve each hour it was available for service. We based revenues from the ancillary service on day-ahead market prices.

Other assumptions:

- We simulated a combined forced and planned outage rate of 8 percent by decreasing total annual net operating revenues by this amount.
- Gas prices used in the analysis are the daily spot market gas prices for southern and northern California.

revenues of $32 to $55/kW-year for NP15 and SP15. This was significantly less than the $90/kW-year net revenue requirement that would be required to signal new investment. However, under the constrained area analysis, the addition of MLCC revenue would have increased the net revenue of a combined cycle unit in SP15 by $16.87/kW-year resulting in net revenue of $72/kW-year.[16] It should be noted that these revenues do not necessarily constitute a stable revenue stream and would unlikely provide an incentive for new generation to locate in a specific area. However, the analysis does demonstrate that there are significant revenue additions possible for units located in constrained areas, although even with the additional revenue from the MLCC, the net revenue is still below the $90/kw-year estimated net revenue requirement for a new combined cycle generator.

We also conducted the unconstrained analysis for the hypothetical combustion turbine. A new combustion turbine unit selling solely into the CAISO imbalance energy and non-spinning reserve markets in 2003 would have received a net revenue in the range of approximately $32 to $36/kW-year for NP15 and SP15 respectively. In 2004, the net revenue for the combustion turbine unit was lower than 2003 levels in NP15 at $21/kW-year but significantly higher in SP15 at $45/kW-year. Net revenue in both zones was much lower than the $78/kW-year cost estimate to support new generation entry of a combustion turbine, this was again primarily as a result of the small volumes transacted in the real-time imbalance energy market. We attribute the increase in revenues in SP15 to the significant increase in the frequency of real-time market splits in 2004 over 2003 levels. This also contributed to the much lower net revenues in NP15 as prices tend to be suppressed during periods of market split.

The unconstrained net revenue results for both a new combined cycle unit and a new combustion turbine are well below the estimated range of revenue that would be needed to stimulate investment in new supply relying only on spot market revenues. These results serve to highlight the key role that forward contracts and/or capacity markets must play in stimulating investment in new supply with the current structure of California's wholesale market and the importance of effective resource adequacy rules to facilitate new generation infrastructure. The constrained area net revenue results that include the additional MLCC revenues illustrate the significant impact this compensation has on revenue adequacy in today's market, increasing the net revenues by more than 30 percent. In 2004, the CAISO paid out more than $285 million in MLCC to generators located in constrained areas for local reliability reasons.

In Chapter 1, we discussed the recent developments in the establishment of resource adequacy standards for the California electric markets. They will establish a framework to ensure that bilateral contracts are secured that provide adequate revenue for suppliers located in transmission constrained areas. Tables 2.7 and 2.8 show the 2003 and 2004 expected capacity factors, energy revenue, ancillary service capacity revenue, operating costs, and net revenue of the combined cycle and combustion turbine units used in this analysis.

[16] The additional net revenue under the MLCC was established by committing the unit in the market only during those periods when 1) it was not profitable to self-commit and 2) when the CAISO had committed a unit in the Los Angeles Basin for reliability purposes.

Table 2.7 2003 and 2004 Financial Analysis of New Combined Cycle Unit

	2003		2004	
	NP15	**SP15**	**NP15**	**SP15**
Capacity Factor	57.6%	60.1%	58.0%	63.4%
Energy Revenue ($/kW-yr)	$ 263.9	$ 280.3	$ 265.8	$ 301.6 + MLCC $ 16.9
Ancillary Service Capacity Revenue ($/kW-yr)	$ 3.2	$ 2.8	$ 3.1	$ 2.9
Operating Cost ($/kW-yr)	$ 220.6	$ 225.6	$ 237.3	$ 249.4
Net Revenue ($/kW-yr)	$ 46.5	$ 57.5	$ 31.7	$ 55.1 + MLCC = $ 72.0

Table 2.8 2003 and 2004 Financial Analysis of New Combustion Turbine Unit

	2003		2004	
	NP15	**SP15**	**NP15**	**SP15**
Capacity Factor	16.0%	20.2%	11.9%	16.6%
Energy Revenue ($/kW-yr)	$ 103.7	$ 130.8	$ 81.1	$ 114.6
Ancillary Service Capacity Revenue ($/kW-yr)	$ 20.6	$ 19.2	$ 13.5	$ 27.8
Operating Cost ($/kW-yr)	$ 91.9	$ 113.6	$ 73.6	$ 97.3
Net Revenue ($/kW-yr)	$ 32.4	$ 36.4	$ 21.0	$ 45.1

2.6 Effectiveness of System-wide Market Power Mitigation Measures

The significant number of long-term contracts the State of California established in 2001 and significant amounts of new generation have provided effective spot market power mitigation from 2002 through 2004 at the system level. When load serving entities are adequately supplied though longer-term arrangements, precise market power mitigation rules become less crucial because the small residual exposure of consumers to spot price volatility will not subject them to large cost impacts. Adequate supply also reduces incentives for supply resources to try to elevate spot prices. Market power mitigation measures are in place to reduce the risk of market manipulation and opportunistic exploitation of contingencies and extreme circumstances. At the same time, mitigation should not excessively dampen spot market volatility, as that may encourage load serving entities to reduce their forward contract cover and rely more on the spot markets. The following section discusses the effectiveness in 2004 of the current market power mitigation measures that affect system-wide real-time market-clearing prices that were implemented in October 2002.

2.6.1 AMP

The CAISO implemented its Automated Mitigation Procedure (AMP) on October 30, 2002, as part of Phase 1B of the Market Design 2002 (MD02) process directed by FERC in its Order of July 17, 2002. AMP is a procedure designed to prevent the exercise of market power and is applied to all bids submitted to the CAISO's real-time market. AMP is also applied to address local market power to both INC and DEC bids awarded out of sequence. We discuss this in Chapter 6 (Intra-zonal Congestion). The following discusses the performance of AMP applied to INC bids paid at the market clearing price.

As in 2003, no supplier in 2004 ever submitted a bid and received a dispatch in response to that bid in which the bid was mitigated. Real-time balancing in 2004 was overwhelmingly in the decremental direction, given sufficient scheduling and commitment of generation pursuant to the must-offer obligation. In the periods in which generation had to be incremented to meet load, the balancing market usually had strong supply relative to demand.

Under the current market rules, AMP is only to be applied in periods where the expected price is above $91.87/MWh. To facilitate this, the CAISO developed a price screen that predicts real-time energy prices for the following hour. Throughout 2004, the AMP price screen had little ability to predict the price for real-time balancing energy for January through September, the period for which data are available.[17] This appears due, in part, to the fact that the price prediction software ran at 53 minutes ahead of the beginning of each hour of operation. Because price spikes so often were due to contingencies and operational activity that would occur closer to the beginning of the hour, or well into the hour, the price screen could not account for these events. The predictive mechanism also repeatedly made false-positive identifications; i.e., hours in which the screen software predicted an incremental price above $91.87/MWh and some quantity of dispatched energy but no such price or dispatch occurred. Table 2.9 shows the number of price spikes, and false-negative and false-positive identifications for January through September 2004.

Table 2.9 AMP Price Screen Test Performance, January through September 2004[18]

	Correct Identifications	False Negatives	False Positives
2004 Q1	1	79	25
2004 Q2	2	42	23
2004 Q3	0	29	18
Total:	3	150	66

[17] RTMA software calculates AMP internally and does not output the results of the price prediction algorithm. Thus, it was not possible to compare predicted to actual prices after RTMA deployment.

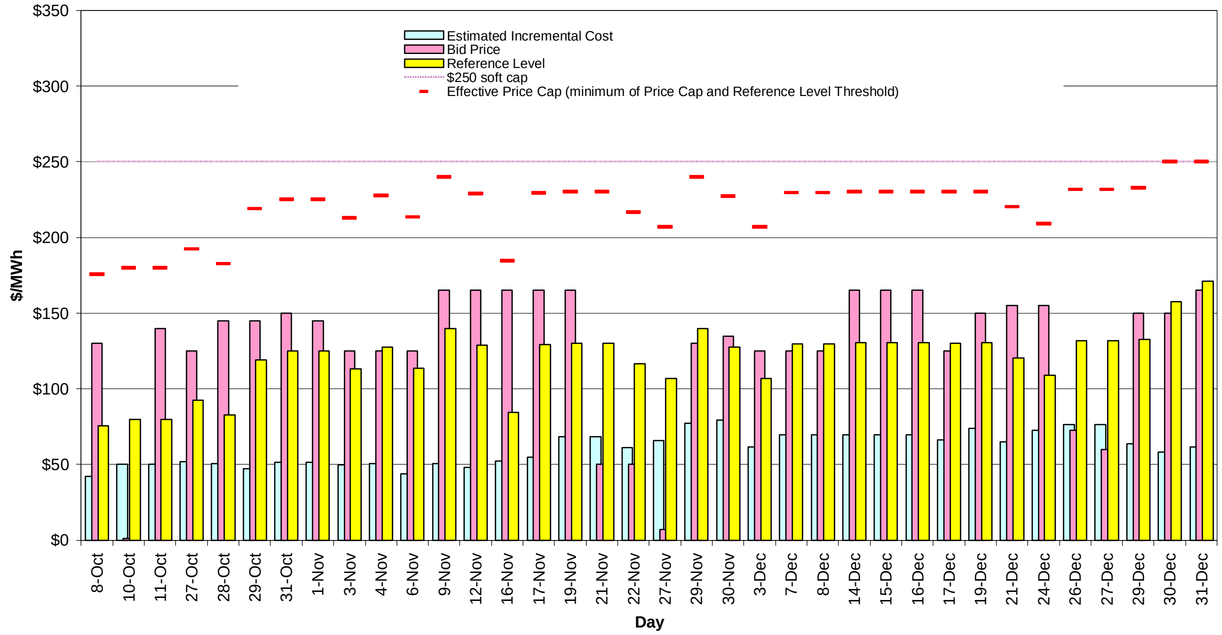
[18] False Negatives are hours in which the predictor did not expect at least one interval price above $91.87 but there was one. False Positives are hours in which the predictor did expect at least one interval price above $91.87 but there were none.

Because of the low predictive power of the price screen, DMA has independently calculated the ability of the conduct and impact tests to limit the exercise of systemwide market power. Since implementation, the impact test has never been violated, and thus AMP has not yet actually mitigated any bids.

Between January and September 2004, units sometimes were able to bid and effectively set high incremental prices, usually during a contingency. Except on rare occasion, these units were bidding in a manner that would not have failed the conduct test. That is, they were bidding within their individual reference level thresholds, no higher than the lesser of $100/MWh above or three times their reference levels. Of the 15 individual price spike hours (with hourly average prices in excess of $100/MWh) between January and September and price-to-cost mark-up in excess of 40 percent of cost, we identified price-setting units as having failed the conduct test in four hours. In actuality, AMP did not detect any of these four hours, because the price screen did not predict prices above $91.87/MWh in those hours and, as a result, the conduct test was not applied.

Between October and December, a small number of units repeatedly acted as price-setters without failing the conduct test. Certain steam generators within SP15 in particular were able to ratchet up reference levels while bidding under conduct test thresholds and then set prices in the range of $155-175/MWh almost daily. This was about $80/MWh above estimated incremental production cost during this period. By late December, these production costs resulted in conduct test failure thresholds in excess of the $250/MWh soft price cap. At this point, the price cap was binding, so a bid that would have failed the conduct test would not have been eligible to set the price anyway. Thus, the “effective price cap” for a unit would be the minimum of the conduct test failure threshold and the $250/MWh price cap. One such unit’s bid prices, reference levels, estimated incremental costs, and “effective price caps” are shown in Figure 2.23. Ratcheting up of reference levels is possible by submitting high bids during uncompetitive real-time market periods which often occur during load ramping periods as discussed under the real-time market performance section earlier in this chapter.

Figure 2.23 Bids, Reference Levels, Estimated Costs, and "Effective Price Cap" for a Unit that frequently set the RTMA Price in 2004 Q4



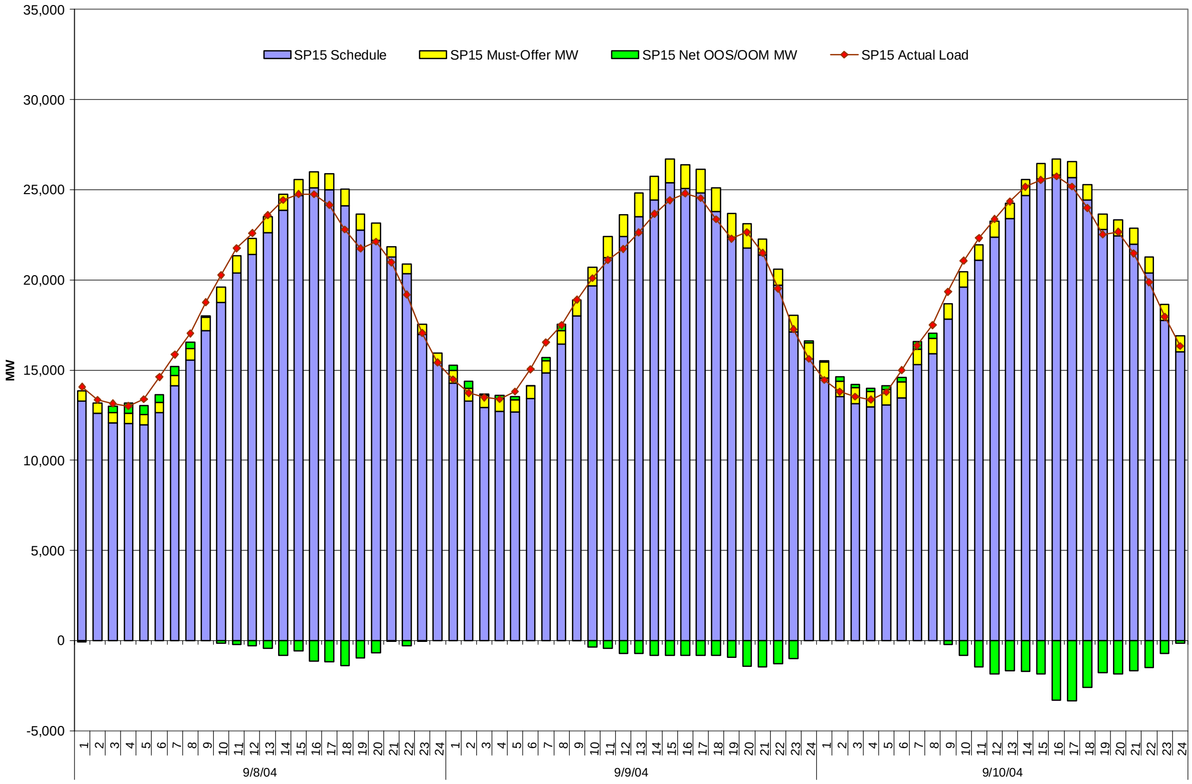
2.6.2 Must-offer

Given the healthy supply conditions during 2004, it could be argued that the must-offer obligation was not critical to mitigate against physical withholding, which likely would not have been a profitable strategy in the 2004 western energy markets. However, the must-offer obligation was used extensively by the CAISO in 2004 to commit units for local reliability reasons. The CAISO frequently denied must-offer obligation waiver requests when generation was needed for local or zonal reliability reasons due to significant intra-zonal congestion within southern California.

As an example, generation capable of producing over 5,000 MW within SP15 was retained at minimum load during the peak days of September 8-10 by denying waiver applications. In order to meet the peak load while simultaneously managing congestion at the Miguel Substation and several other choke points, the CAISO committed units with minimum-load output of 877 MW during the SP15 all-time peak hour on September 10, between 3:00 and 4:00 p.m. The must-offer-committed units themselves provided a total of 3,985 MW of generation at the peak. The committed generation in addition to forward scheduled energy was sufficient for balancing supplemental energy to cover the all-time SP15 peak load of 25,473 MW, without resorting to out-of-market procurement for a system condition.[19] Figure 2.24 compares SP15 actual load to SP15 scheduled volume, must-offer procured generation operating at minimum load, and OOS/OOM procurement, for September 8-10, 2004.

[19] In this hour, the CAISO procured 6 MWh of incremental energy and 3,416 MWh of decremental energy out of sequence and/or out of market to manage intra-zonal congestion. No incremental energy was procured to manage a system condition.

Figure 2.24 SP15 Actual Load v. Scheduled, Must-Offer, and OOS Energy, Sept. 8-10



2.6.3 Damage Control Price Cap

Pursuant to the breakpoint price cap methodology directed in FERC Orders of April 26 and June 19, 2001, and affirmed in later Orders, bids at or above $250/MWh that receive dispatches are paid as bid (i.e., paid their bid price). The market-clearing price in those intervals is set by the highest-priced dispatched bid below $250/MWh.

In general, the $250/MWh price cap on incremental prices and the -$30/MWh price cap on decremental prices did not constrain real-time market clearing prices in 2004. As we noted previously, the $250/MWh incremental soft price cap was binding for only five units whose reference level exceeded $150/MWh in late December (described above in Section 2.4.1). The price cap was not binding in any hour between January 1 and October 13, 2004. Beginning October 14, and continuing intermittently through December 31, two units did submit bids at or above the $250/MWh soft price cap and received dispatches, all between 9:00 p.m. and 1:00 a.m. One such unit, on October 14, had applied for a waiver from the must-offer obligation but had been denied. As a result, it was entitled to receive minimum-load cost compensation. The other unit had bid supplemental energy at exactly $250/MWh, and was dispatched on 11 different days between November 16 and December 23.

The -$30/MWh decremental price floor was binding in approximately 15 hours between January and September 2004 (BEEP), and in an additional 59 hours between October and December 2004 (RTMA). In all but one case, one or more scheduling coordinators submitted bids at -$30/MWh, received dispatches, and were paid as bid. Actual decremental market-clearing prices during these periods ranged from -$0.01 to $41/MWh and were most often $5.31/MWh. On December 16, a bid from an import of -$250/MWh was dispatched for approximately 3 MWh, and was paid as bid; i.e., the bidding scheduling coordinator received $250/MWh to decrement output. The market-clearing price during these intervals ranged between -$0.33 and $220/MWh.