4. Ancillary Services Markets

4.1 Summary of A/S Market Performance in 2004

- On a weighted average basis, the price of ancillary services declined by 12 percent compared to 2003.
- Regulation prices decreased, only slightly in the case of regulation up, but quite substantially in the case of regulation down.
- Spinning reserve and non-spinning reserve prices increased slightly.
- The CAISO started procuring reserves zonally in the latter half of 2004. It made other changes to the market to enhance supply, principally allowing units constrained under the must-offer provisions to bid into the spin and non-spin markets without being financially penalized.

4.2 Background

The CAISO procures regulation, spinning reserve and non-spinning reserve in the day-ahead and hour-ahead markets such that the total procurement plus self-provision meets or exceeds the WECC minimum operating reliability criteria (MORC) and NERC control performance standards (CPS2). The CAISO procures ancillary services at the lowest overall cost while maintaining the reliability of the system and the competitiveness of the markets. The definitions for the three ancillary services are:[1]

- **Regulation**: Provided by generation that is running and synchronized with the CAISO controlled grid, so that the operating level can be increased (incremented) or decreased (decremented) instantly through automatic generation control (AGC) to allow continuous balance between resources and demand. The CAISO operates two distinct capacity markets for this service, regulation up and regulation down.
- **Spinning Reserves**: Provided by generation that is running ("spinning") with additional capacity that is capable of ramping over a specified range within 10 minutes and running for at least two hours. The CAISO needs spinning reserve to maintain system frequency stability during emergency operating conditions and unforeseen load swings.
- **Non-spinning Reserves**: Provided by generation that is available but not running. It must be capable of being synchronized to the grid and ramping to a specified level within 10 minutes, and then be able to run for at least two hours. Curtailable demand can provide non-spinning reserve provided that it is telemetered and capable of receiving dispatch instruction and performing accordingly within 10 minutes. The CAISO needs non-spinning reserve to maintain system frequency stability during emergency conditions.

1 The CAISO no longer procures replacement reserves.

CAISO market participants can self-provide any or all of these A/S products, bid them into the CAISO markets, or purchase them from the CAISO. The CAISO procures two other ancillary services on a long-term basis: *voltage support* and *black start*. It does this primarily through reliability must run (RMR) contracts. In the rest of the section, we use the term "ancillary services" only to refer to the three reserves defined above.

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

4.3 Changes in Market Structure in 2004

The CAISO made substantial changes in its A/S markets during 2004. There were two main initiatives: to procure A/S zonally when system conditions warranted such a split, and to allow units that were constrained under the provisions of the must-offer obligation (MOO) to bid into the day-ahead (DA) markets without losing their minimum load cost compensation (MLCC) and uninstructed energy (UE) payments. There were a number of reasons for these initiatives. The most immediate were the heightened sensitivity to reserve requirements in the aftermath of the August 14, 2003 Northeast Blackout and the thinning A/S bid stack in SP15.

4.3.1 Zonal Procurement

Traditionally, the CAISO procured A/S across the entire control area based on least cost. This approach was adequate when the availability of the services themselves was evenly distributed, and when there was sufficient reserve transfer capability between zones. In 2004, the CAISO began to notice that it procured most of its A/S from NP15 and less from SP15, the inverse of the load ratio between the two zones. There were a number of factors that contributed to this change:

- Increased energy imports from the southwest resulted in generators in SP15 staying off-line.
- In 2004, about 2,000 MW of additional RMR capacity was under Condition 2 of the contract, which units only bid into the A/S markets if they have been dispatched by the ISO and have any remaining capacity available. This 2,000 MW of capacity represents about 300 MW of potential 10-minute reserve capacity that was often not bid into the A/S markets.
- More A/S capable units came online in NP15. This new A/S capability displaced the less efficient units in SP15, which had proportionally fewer A/S capable new units come online.
- Through the first half of the year, market rules established that units constrained on under the must-offer obligation were not able to bid into the A/S markets without jeopardizing their MLCC and UE payments.

> This became a problem particularly in SP15. This was the zone with the most intra-zonal constraints (South-of-Lugo, Sylmar, SCIT, etc.). Generating units in the south were constrained on and prevented from bidding into the A/S markets, thereby thinning the A/S bid stack in that zone.

By the first quarter of 2004, the CAISO was procuring approximately 85 percent of A/S in NP15. The CAISO questioned the deliverability of these reserves and determined that such a least-cost procurement pattern was not giving enough emphasis to deliverability. Consequently, the CAISO embarked on a series of initiatives aimed at making the procured ancillary services inherently more deliverable by changing the procurement pattern, as well as trying to increase the volume of the bid stack, especially in the south. A more voluminous bid stack would, most likely, lower the overall cost of A/S, as well as ameliorate any market power concerns, which are particularly sensitive issues when bid sufficiency is low.

The CAISO had always retained the authority to split zones, but had ceased doing so in 2001. The CAISO began a dialogue with stakeholders in the spring of 2004 with the aim of explaining the issues to participants and seeking approval for its proposed zonal procurement solution. This solution allowed operators to forecast the flows on Path 26 to determine whether or not zonal procurement was necessary. They would procure zonally if it was. The CAISO held stakeholder meetings, produced a white paper on zonal competitiveness, and solicited comments. The process resulted in a decision to go ahead with zonal procurement during times of insufficient transfer capability between northern and southern California and to dovetail the issue with the MLCC initiative mentioned below. On August 3, 2004 the CAISO reactivated the practice of splitting the procurement of ancillary services when necessary.

4.3.2 Amendment 60 Minimum Load Cost Compensation

The Federal Energy Regulatory Commission (FERC) created the must-offer obligation in its April 26, 2001 Order as a market power mitigation measure during the 2000-2001 western electricity crisis. The purpose of the must-offer obligation was to prevent physical withholding by requiring that any in-state supplier transacting business on the CAISO controlled grid (except for hydro-electric generation) must bid any available capacity (i.e., not on outage or already committed in a bilateral transaction) into the CAISO's real-time market. Over time, the CAISO has struggled to arrange a method of compensation for these generators that would not result in perverse incentives. There have been a series of compliance filings that have attempted to strike an appropriate balance. The most recent of these was initiated by concerns voiced about the MLCC process at a technical conference in Washington, D.C. in September 2003. As a result, the CAISO undertook to re-examine the must-offer process. It subsequently held stakeholder meetings on October 8 and 27, 2003, November 19, 2003, January 16, 2004, and March 10, 2004.

4.3.2.1 Previous Relationship Between MLCC and A/S bidding

Under the pre-existing market rules, the CAISO would rescind MLCC payments for each hour in which a generating unit was awarded or self-provided ancillary services. CAISO findings indicated that the revenues from the A/S markets alone were generally insufficient to cover a unit's start-up and no load operating cost. However, if a unit

received the MLCC payment, its operating costs were usually exceeded by the magnitude of the UE payment. Thus, generators that were committed by the CAISO and were likely to receive the MLCC and UE payments were unlikely to risk these payments by bidding into the A/S market. This was especially true given the inherently unpredictable nature of the hour-by-hour awards and the price setting mechanism. Additionally, over 90 percent of A/S procurement was done in the day-ahead market, which ran from 10:00 a.m. to 1:00 p.m. However, the units that were constrained would only know their final status at 8:00 p.m. that evening. If they wanted to bid into the A/S market, they would have to gamble with the uncertainty of being committed by the CAISO later in the day.

The CAISO thus made two proposals concerning A/S:

1. To remove the disincentive to bid into the ancillary services markets, the CAISO proposed to pay MLCC even if a unit was awarded ancillary services. This would remove the disincentive to bid into the A/S markets.
2. The CAISO proposed a new must-offer waiver (MOW) and A/S timetable:
    a. Waiver requests must be submitted by the deadline for submitting initial preferred schedules to the CAISO (typically 10:00 a.m.).
    b. The CAISO would then publish advisory energy and ancillary service schedules at approximately 11:00 a.m.
    c. The CAISO would then grant or deny waiver requests by 30 minutes after the time those advisory schedules were published (approximately 11:30 a.m.).
    d. Must-offer generators may then bid into the day-ahead ancillary service markets when revised preferred schedules are submitted (12:00 p.m.).

Under this proposal, a unit owner would know if the unit had been granted a waiver prior to the final publication of A/S schedules. This would allow CAISO committed units to bid into the A/S markets. The units constrained on would only be able to bid into the spin and non-spin markets, as the regulation up and down markets require a forward schedule. The spin and non-spin services also suffered from inadequate bid sufficiency.

The stakeholder community substantially accepted both of these issues. On July 11, 2004, the CAISO stopped making units ineligible for MLCC when they had a final HA A/S award. Later, on September 1, 2004, the CAISO moved the MOW Denial notification back so that it occurred between the Preferred and the Revised Preferred A/S runs. Both of these dates are evident in Figure 4.1 that shows the bidding behavior of units that have been committed by the CAISO. Prior to July 11, bidding into the A/S markets was the exception rather than the rule. Thereafter, hour-ahead bids became common, and once the market timing changed, day-ahead bids increased at the expense of the hour-ahead bids.

Figure 4.1 Hourly Average Gross Capacity Bid into DA and HA Markets by Constrained-On Units

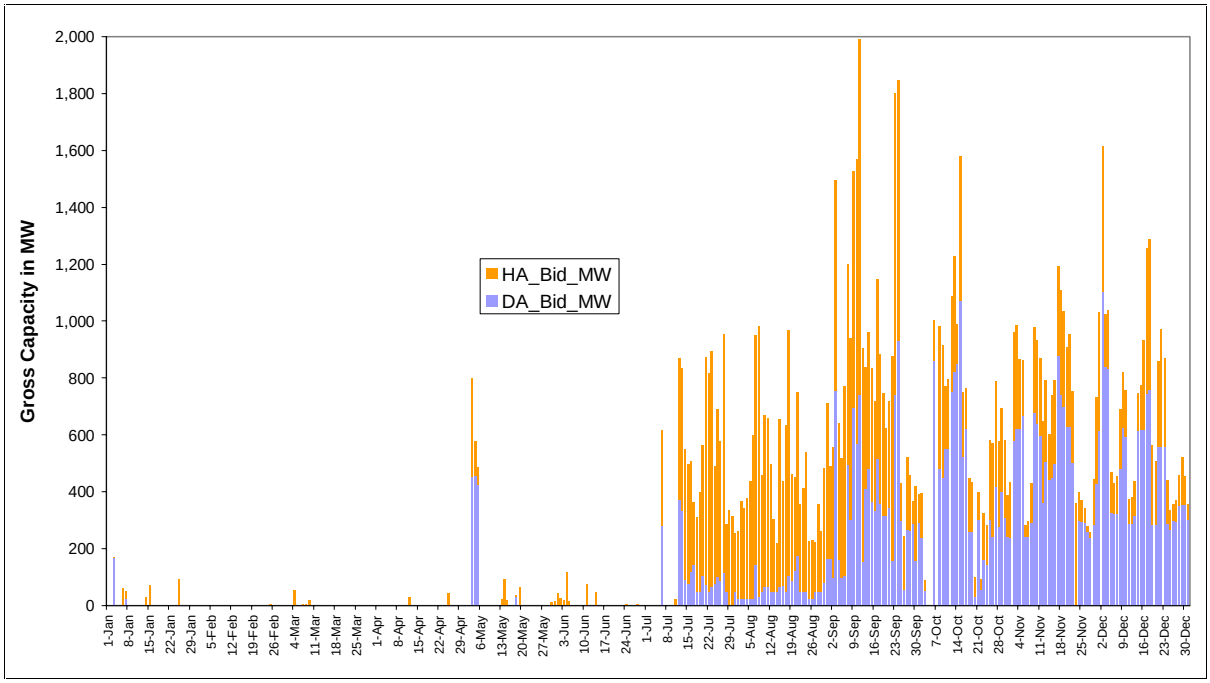
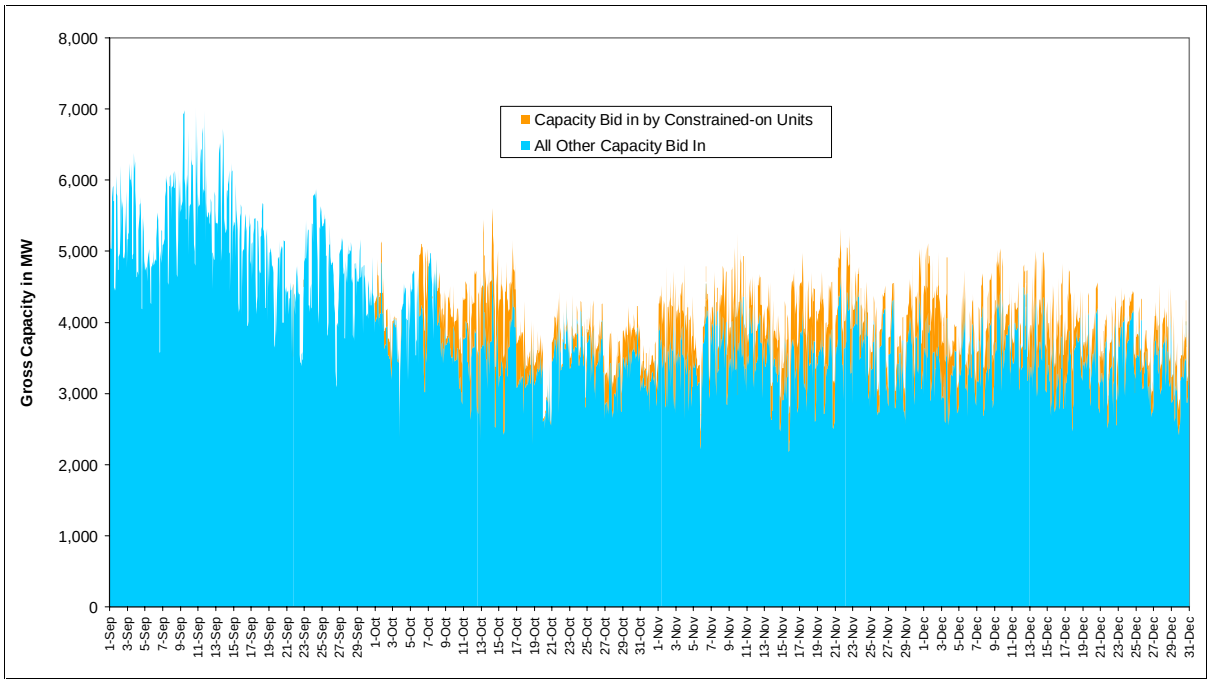


Figure 4.2 shows the extent to which the extra capacity provided by units that were committed by the CAISO, but had previously been unable to provide capacity, has served to increase the gross capacity offered into the CAISO's spin and non-spin markets. On average, in the last quarter of 2004, the incremental capacity available in the spin and non-spin day-ahead markets due to the non-rescission of MLCC payments rule change increased the total capacity bid into those markets by 12.3 percent.

Figure 4.2 Incremental A/S Capacity Provided by Constrained-On Units in the Day Ahead Market

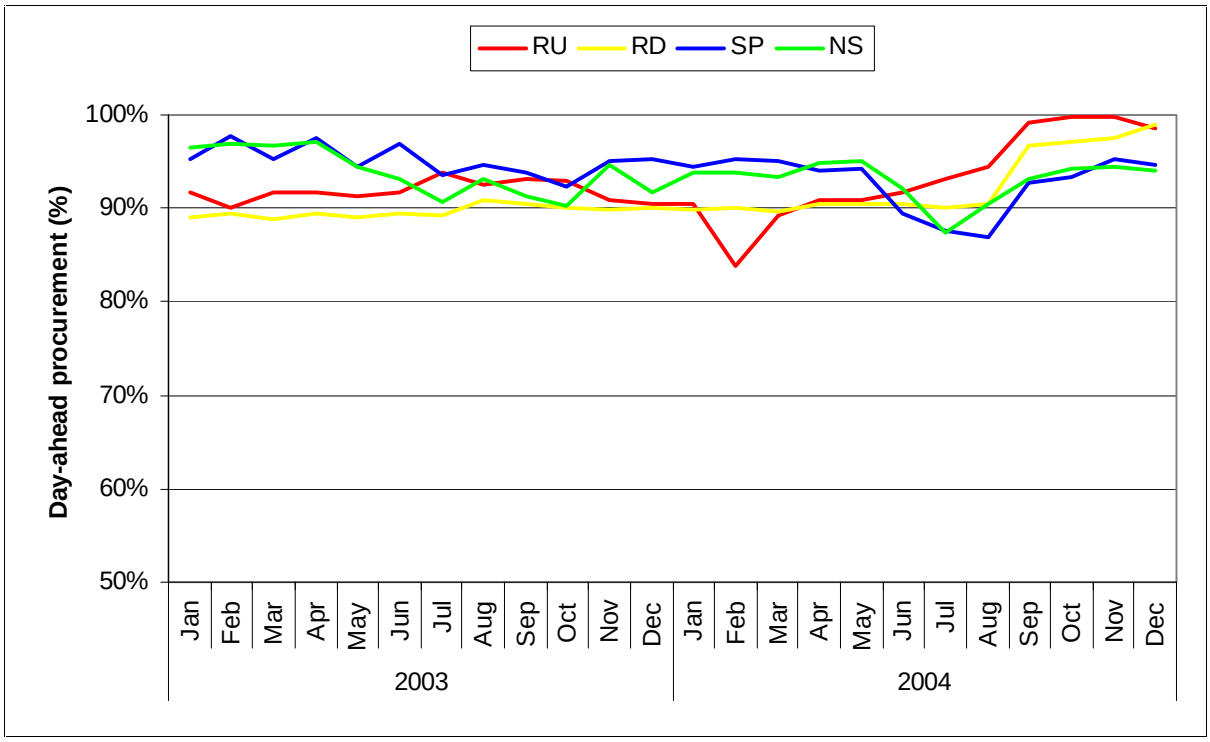


4.3.3 Other Issues in the A/S Markets

4.3.3.1 100 Percent Day Ahead Procurement

The CAISO had always split its procurement of ancillary services between the day-ahead and hour-ahead markets. Traditionally, the CAISO procured approximately 90 percent of the capacity it needed in the DA market. This allowed it to take advantage of better load forecasting as real-time approached and lower overall costs. The CAISO decided that it should move to 100 percent DA procurement. The major reason for this was to improve reliability. If bid sufficiency was poor, sometimes the CAISO would not know if it was deficient until the HA market closed (three hours before real-time). If this happened, then the CAISO had few choices from which to procure extra supplies in the short window before real-time. By moving to 100 percent DA procurement, the CAISO would know the day before whether or not sufficient A/S could be procured through the market. If not, the CAISO could take the necessary steps, such as using RMR capacity. The effect of this change can be seen quite clearly in Figure 4.3. 100 percent DA procurement began on September 1, 2004. Figure 4.3 shows a marked shift upwards after August. There is still some procurement in the HA markets, mainly due to load forecast changes, outages, and occasionally bid-sufficiency problems in the DA market.

Figure 4.3 Hourly Average Day-Ahead Procurement, 2003-2004



4.3.3.2 Continuing Challenges Regarding RMR Contracts

For some time now, the A/S market has faced challenges concerning RMR contracts, particularly Condition 2 RMR contracts. Each year, the CAISO contracts with specific units required to support reliability in designated local areas. Units with RMR Condition 2 contracts receive full cost recovery but are subject to restrictions on both operation and participation in the CAISO markets. Condition 2 units are not permitted to run unless dispatched by the CAISO for local reliability under the terms of their contract. Condition 2 units are required to bid any remaining available capacity into the CAISO ancillary service markets after being dispatched (in the day-ahead or hour-ahead) by the CAISO but are prohibited from bidding in otherwise. While this restriction is instrumental in preserving the availability of limited-use resources for times when local reliability conditions require additional energy support, the restriction also results in hours when a unit could have provided ancillary services to the CAISO but was not permitted to do so. Combustion turbines under Condition 2 contracts, for example, could easily provide non-spinning reserve when not needed for local reliability. This extra supply would help alleviate bid insufficiency and lower prices, especially during shoulder season months. The CAISO has calculated that, on average, there are about 145 MW of non-spinning reserve in SP15 and 230 MW in NP15 that fall into this category on an hourly basis. If these units were allowed to bid their capacity into the non-spin market, then CAISO estimates suggest that annual cost savings of approximately $7.8 million could be realized. The current RMR pro forma contract does not allow this and, unfortunately, its negotiation not long after the startup of CAISO operation was protracted and litigious. Consequently, there is a deep reluctance to reopen this issue despite its documented inadequacies.

4.4 Prices and Volumes

Overall, ancillary services prices decreased 12 percent from a weighted average price of $9.81 in 2003 to $8.63 in 2004. The overall price decrease was driven by a substantial decline in the cost of regulation down, which fell 40 percent from $18.43 in 2003 to $10.95 in 2004. Regulation up prices declined slightly, while spin and non-spin increased by 10 and 5 percent respectively. Overall A/S procurement volumes increased by 5 percent over 2003, across all services, with the exception of regulation down, which dropped 1.9 percent in volume. Regulation up volume showed almost no increase.

Table 4.1 Annual A/S Prices and Volumes, 1999-2004[2]

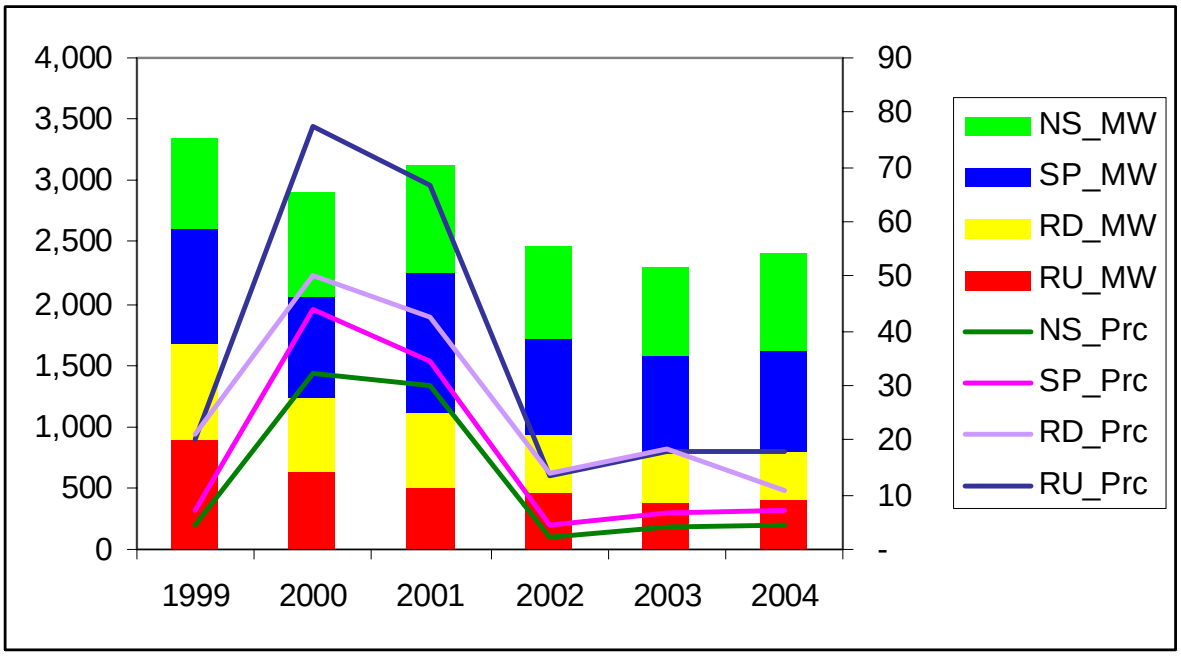
	Year	RU	RD	SP	NS	GrandTotal
Price in $	1999	20.22	20.84	7.07	4.35	11.97
	2000	77.28	50.15	44.07	32.46	41.03
	2001	66.72	42.33	34.69	30.03	36.42
	2002	13.41	13.76	4.66	2.15	7.08
	2003	18.08	18.43	6.62	4.20	9.81
	2004	17.95	10.95	7.25	4.43	8.63
Volume in MW	1999	903	769	942	735	3,687
	2000	633	594	818	861	3,479
	2001	492	614	1,148	862	3,420
	2002	460	469	775	763	2,524
	2003	381	416	767	722	2,309
	2004	395	408	817	782	2,427

The price and volume pattern since 1999 are shown below in Figure 4.4.[3]

2 Average A/S prices – whether annual or monthly – are computed by weighting the hourly prices for each market against the total procurement of the product. This computation values the portion of the service that was self-provided at the market price.

3 The ancillary services markets have changed in several ways since their inception. These changes are depicted in this graph. During 2000-2001, reserves were procured at atypical levels to maintain reliability through the energy crisis. During 2002, replacement reserve procurement was suspended. Also during 2002, the calculation for the regulation reserve requirement was modified resulting in reduced procurement. For these reasons, 2000 and 2001 are atypical years.

Figure 4.4 Annual A/S Prices and Volumes, 1999-2004

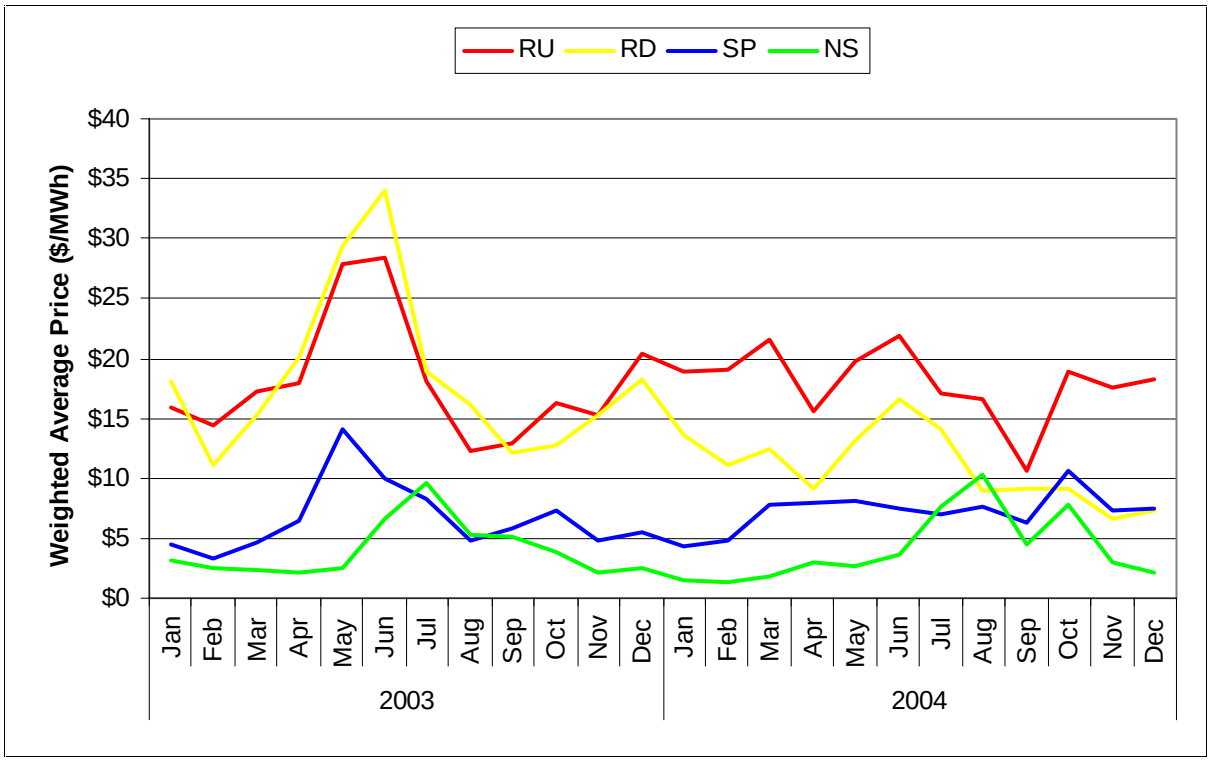


4.5 Monthly Prices

Figure 4.5 shows the price pattern by month over the last two years. The regulation prices had much the same pattern as last year, with less noticeable peaks in May and June of 2004. Price spikes during the early summer are related to the snowmelt, as hydroelectric resources, which often supply capacity in the A/S markets, are instead selling energy. This thins the bid stack and results in deeper procurement through the bid stack. Non-spin prices had much the same pattern as 2003 with a summer spike caused by greater market power in the high load months. Regulation up, spin and non-spin all had subsequent coincident peaks in October of 2004 for a number of different reasons.

- The maintenance season began in October but this decrease in available capacity was poorly correlated with the decline in load, which took a few more weeks to manifest itself.
- Phase 1B was implemented on October 1, 2004 and the CAISO procured increased quantities of regulation up and regulation down for the first month of operation. Higher procurement of regulation up, in particular, resulted in less capacity available to provide spinning reserve and, hence, higher prices and deeper procurement through the bid stack for that service.
- There was increased market splitting in October, which had the effect of increasing prices in SP15 and decreasing them in NP15.
- The Pacific DC intertie was taken completely out of service for the last quarter of 2004 resulting in operational constraints.

Figure 4.5 Monthly Weighted Average A/S Prices, 2003-2004

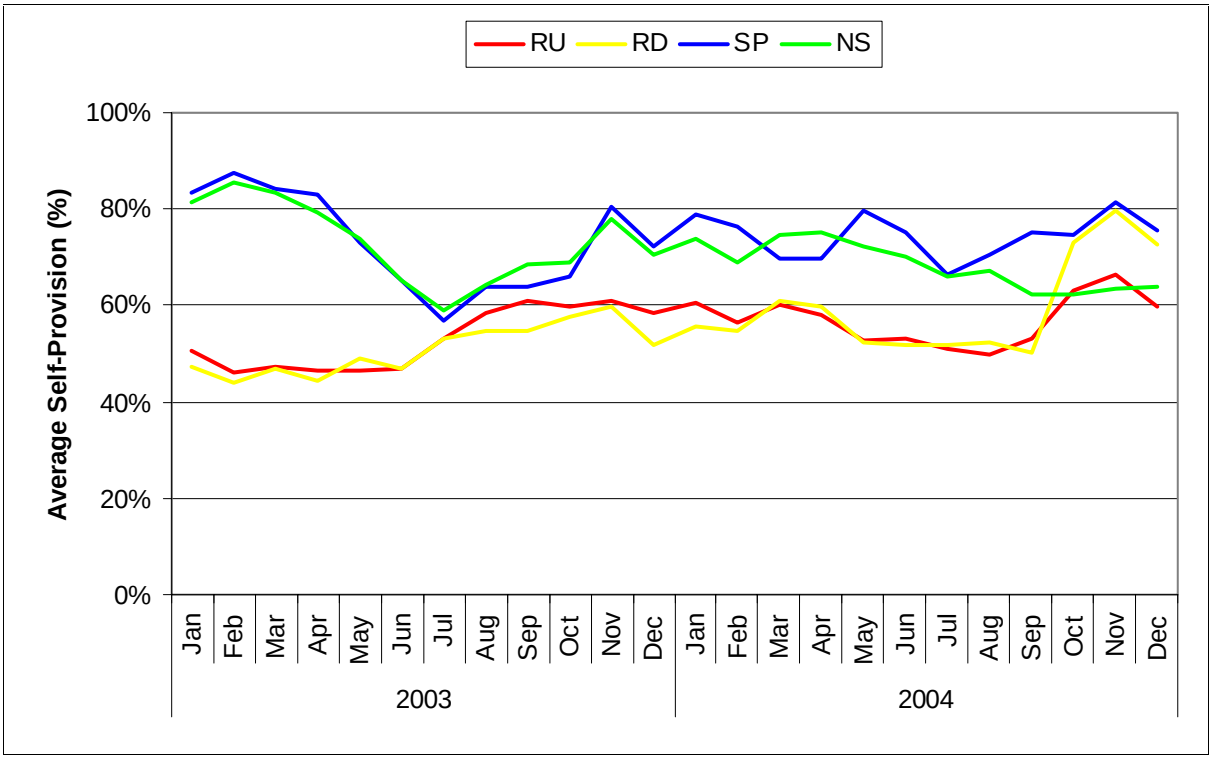


4.6 Ancillary Service Market Supply

4.6.1 Self Provision

Self-provision of ancillary services continued to be a major component in the A/S markets in 2004. There was average self-provision of between 50 and 80 percent of A/S requirements. There is less self-provision of regulation than spinning and non-spinning reserve. All services saw an increase in self-provision in October and November. This was most likely a consequence of the increase in market prices, which encouraged load serving entities to self-provide. Figure 4.6 shows this graphically.

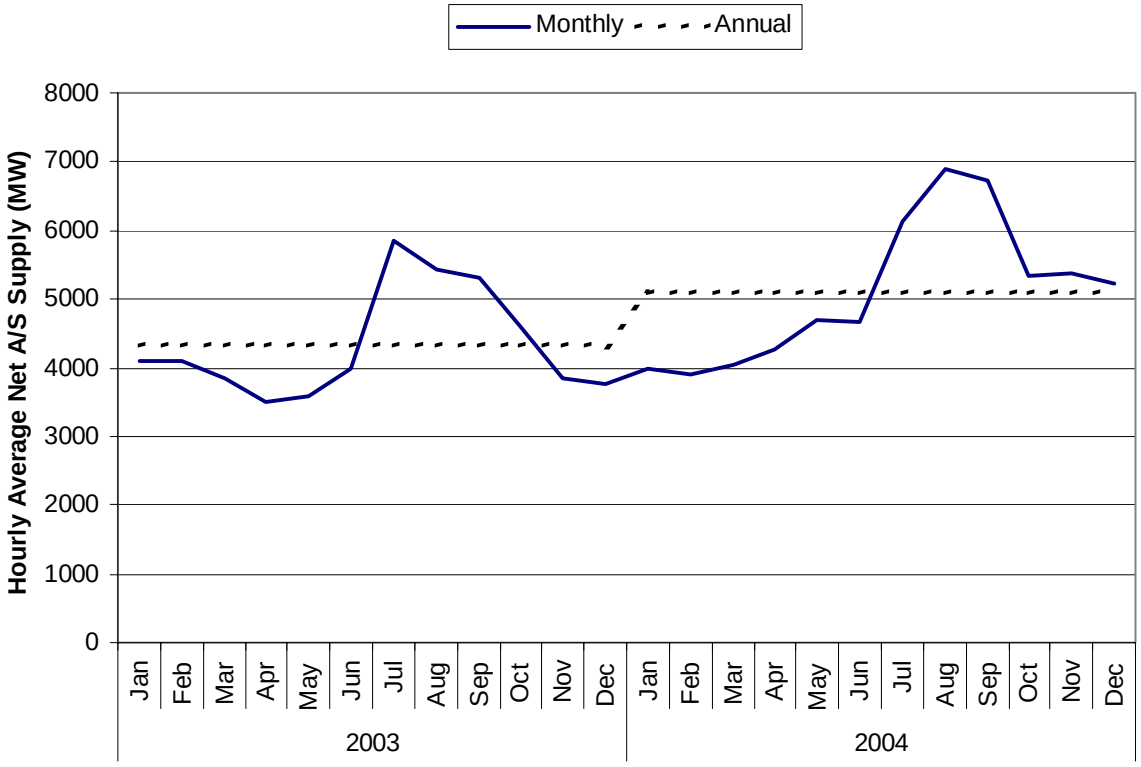
Figure 4.6 Hourly Average Self-Provision, 2003-2004



4.6.2 Market Supply

Offers of physical capacity to the A/S markets increased by 18 percent from 2003 to 2004. We attribute some of this increase to the removal of the disincentive to bid into the A/S markets by units constrained on under provisions of the must-offer-obligation on July 11, 2004. The monthly pattern in Figure 4.7 shows both the increase in supply as more units turn on in the summer and the sharp drop-off in supply between September and October, which resulted in an increase in self-provision and an increase in A/S prices.

Figure 4.7 Average Hourly Net A/S Supply by Month, 2003-2004[4]

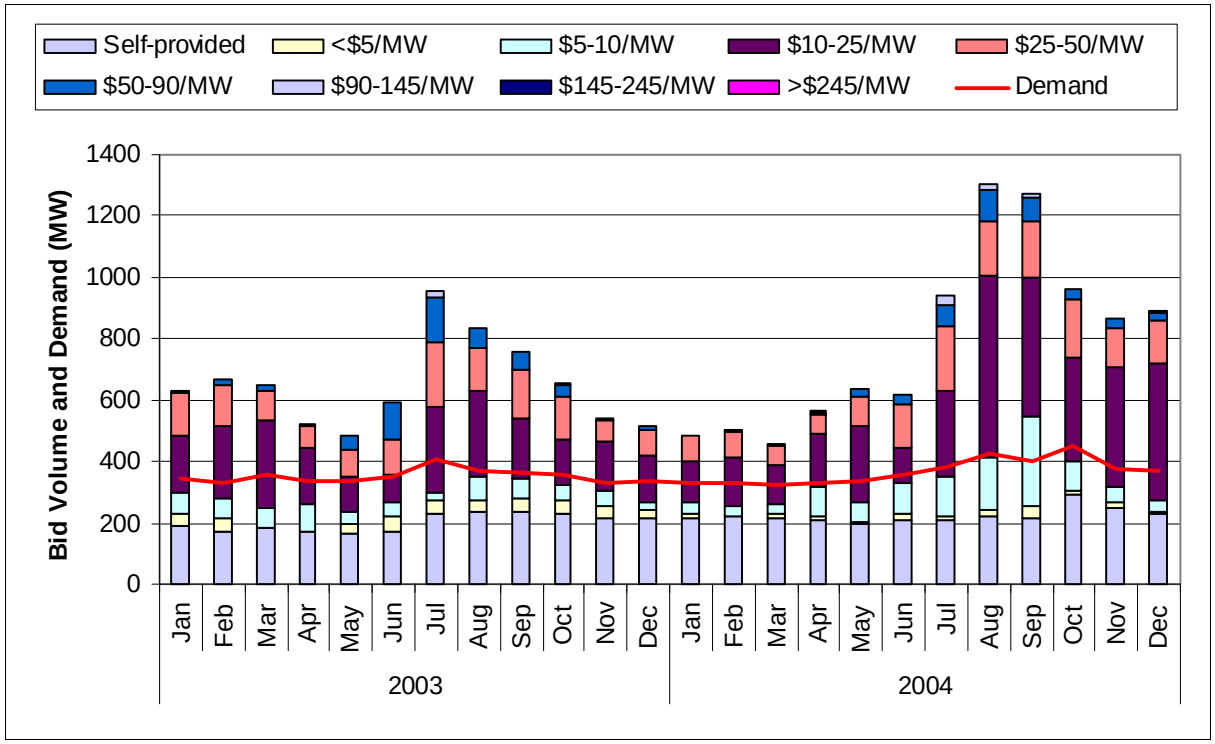


4 Net A/S supply measures the physical capacity offered to the market. The same physical capacity can be offered to several markets in the case of upward reserves. The market clearing mechanism only allocates the capacity to one market. For this reason, summing the capacity offers from a resource overstates the physical capacity offered to the markets. This does not apply to self-provision, because the SC allocates the capacity to each market.

4.6.2.1 Regulation Up (RU)

The increase in market supply of regulation up is clearly visible in Figure 4.8, especially in August and September. Much of the increase in supply was in the $10-$25 range. As can be seen in Figure 4.8, the higher prices in October were due, in part, to higher procurement of regulation up during the first month of Phase 1B implementation and to slightly reduced supply due to maintenance outages.

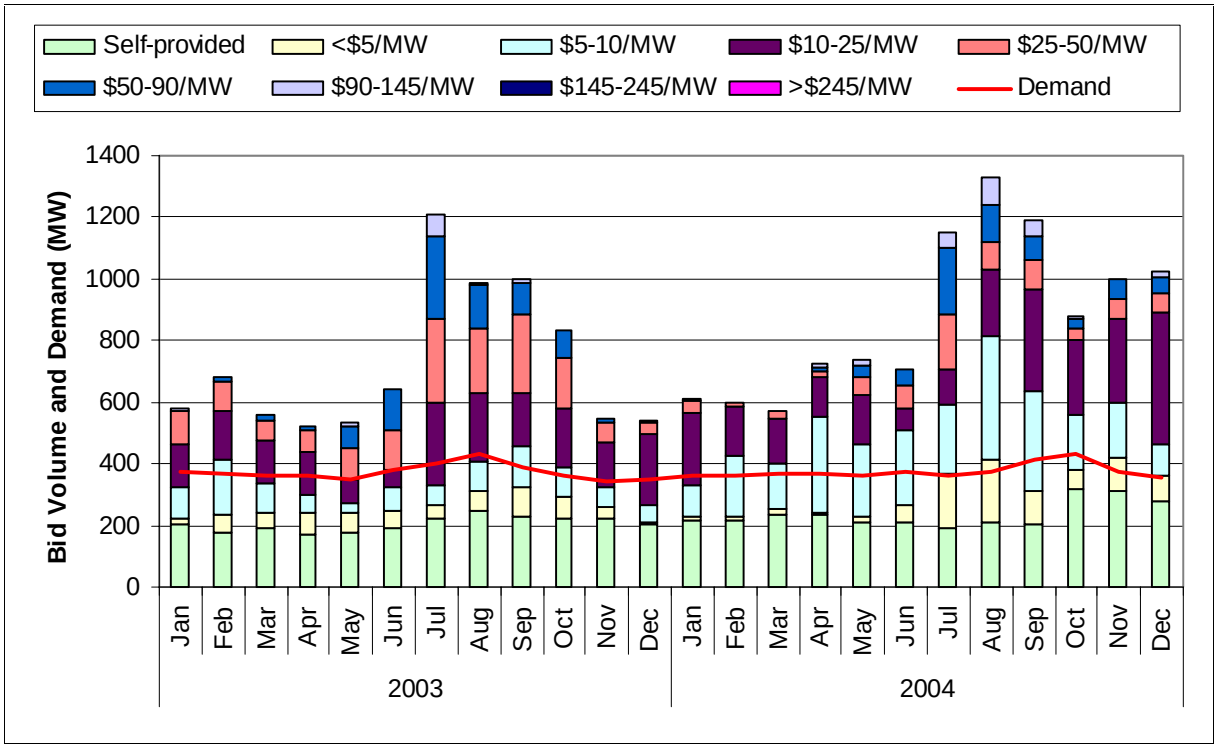
Figure 4.8 Hourly-Average, Day-Ahead Regulation Up Bid Composition, 2003-2004



4.6.2.2 Regulation Down (RD)

The price of regulation down decreased substantially during 2004. There was a significant increase in the supply of lower priced bids, especially in the $5-$10 bid range, which accounted for the decrease in regulation down prices in 2004 from 2003. Load growth in 2004, particularly in the off-peak period, helped to provide greater downward capacity. Figure 4.9 shows that the higher prices in October were also due, in part, to higher procurement of regulation services during the first month of Phase 1B implementation.

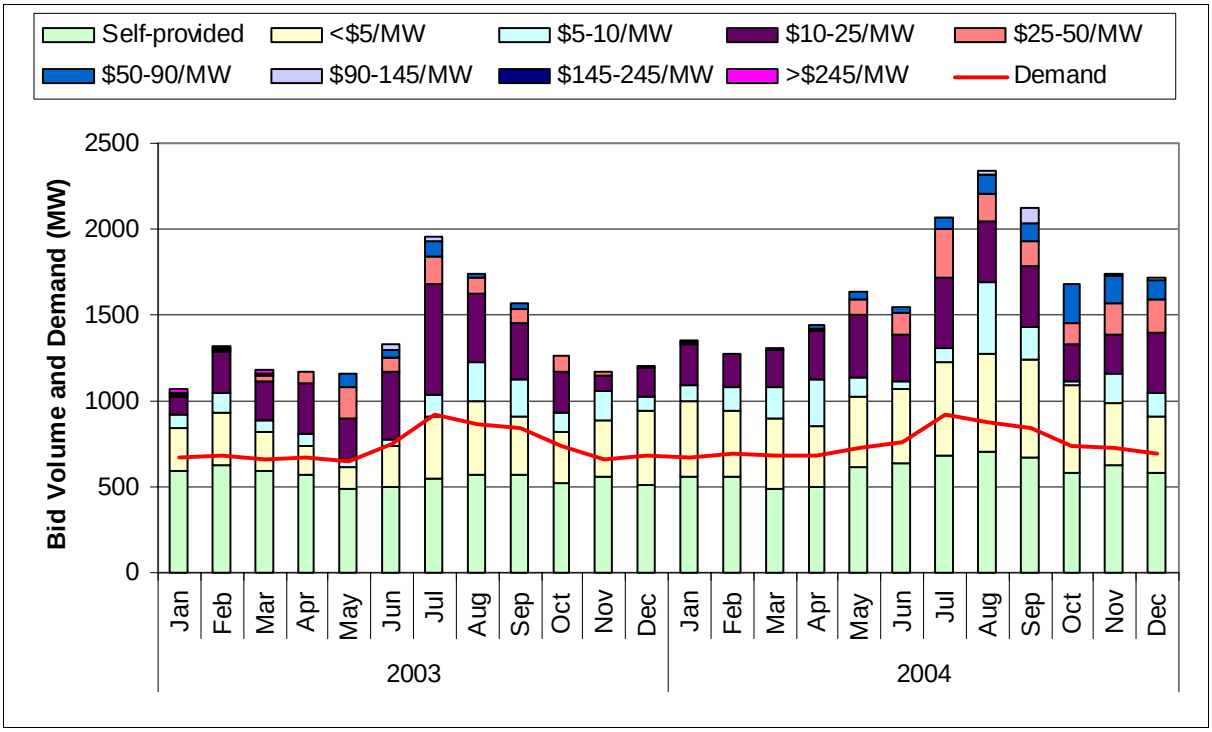
Figure 4.9 Hourly-Average, Day-Ahead Regulation Down Bid Composition, 2003-2004



4.6.2.3 Spinning Reserves (SP)

Spinning reserve prices were moderate during most of 2004. However, the spinning reserve market was subject to price spikes especially in August due to high loads as well as in October for the reasons mentioned in Section 4.5. The procurement, shown in Figure 4.10, did not change as it did for regulation up and regulation down.

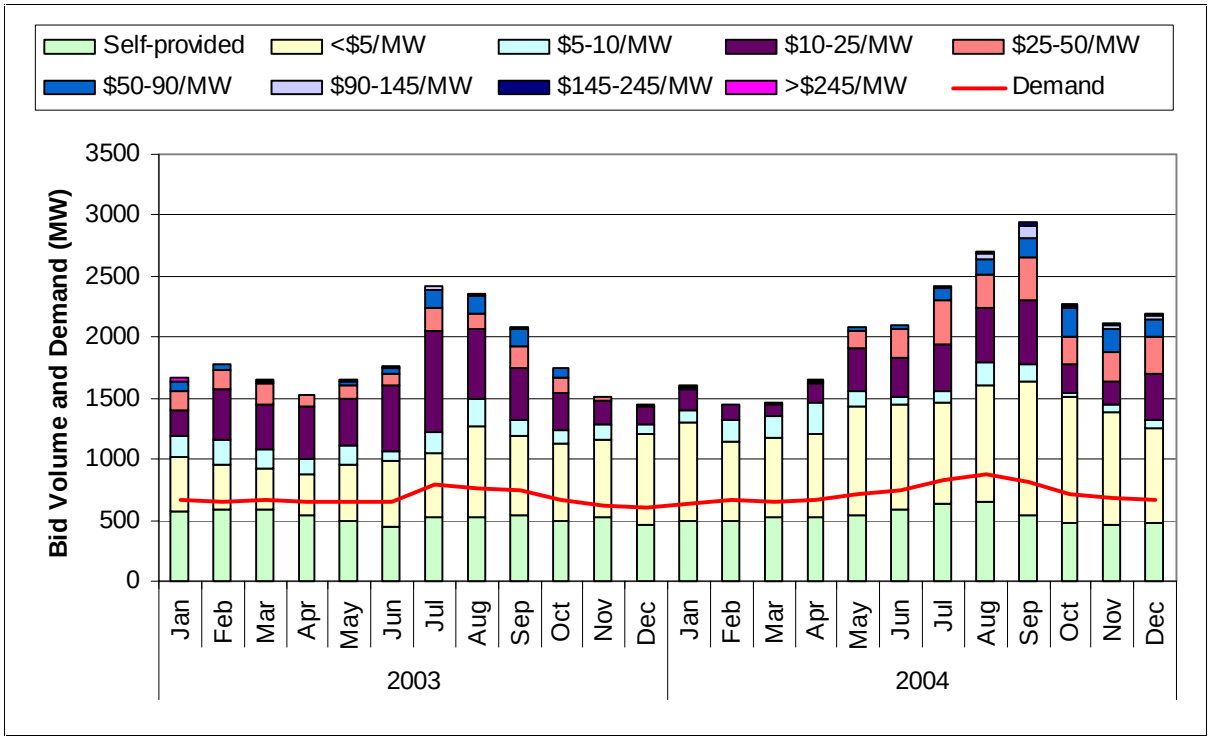
Figure 4.10 Hourly-Average, Day-Ahead Spinning Reserve Bid Composition, 2003-2004



4.6.2.4 Non-spinning Reserves (NS)

The non-spinning reserve (NS) markets experienced similar changes to those in the spinning reserve markets. However, like spinning reserve, it also did not have increased procurement in October as regulation up and regulation down did.

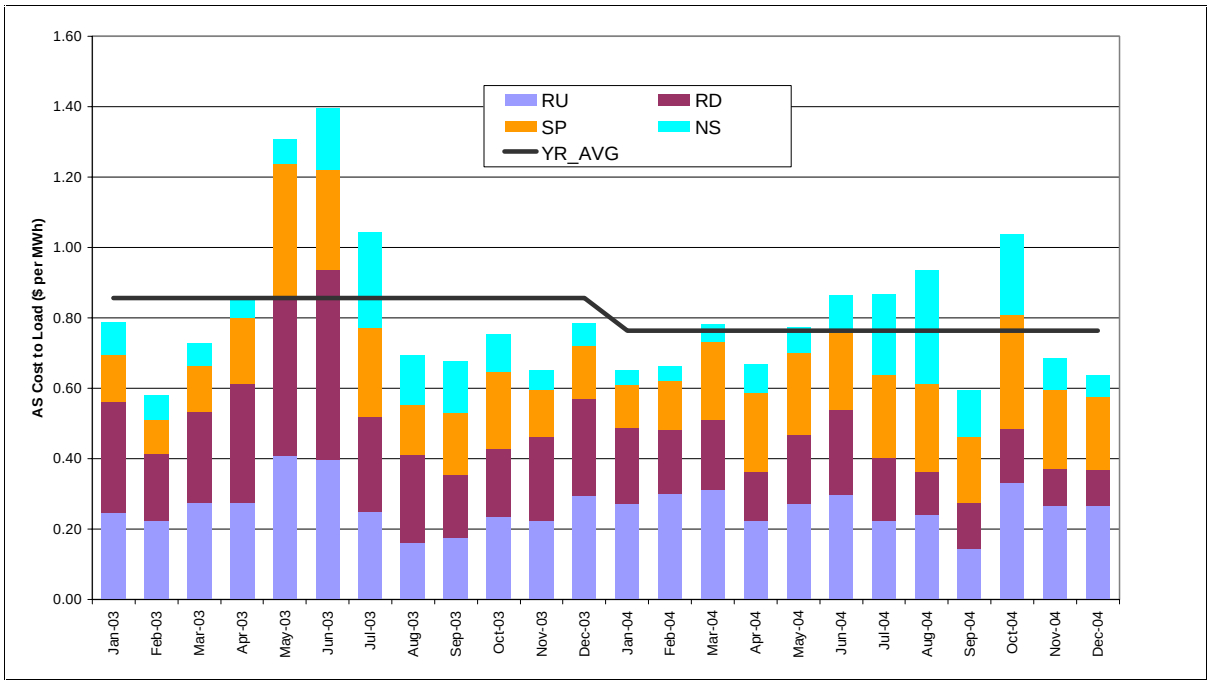
Figure 4.11 Hourly Average Non-Spinning Reserve Bid Composition, 2003-2004



4.7 Cost to Load

The cost of ancillary services to load fell by 11 percent from an average of $0.856/MWh in 2003 to $0.763/MWh in 2004. The monthly variation of this cost is shown in Figure 4.12.

Figure 4.12 Monthly Cost of A/S per MWh of Load



4.8 Bid Sufficiency

We define bid sufficiency as having sufficient available capacity bid into the markets to meet minimum requirements. This is a very conservative measure of bid sufficiency as all suppliers in these hours are pivotal. Bid sufficiency is viewed as a market problem in that, should the market supply of A/S be exhausted or should there be fewer than two suppliers, the CAISO can procure A/S from RMR units. Bid sufficiency deteriorated in 2004 compared to 2003. Bid sufficiency is measured in two ways: the gross capacity short, and the number of hours for which there was a shortage. In August and December of 2004, for example, the capacity shortage was much greater in August even though there were more shortage hours in December. The total capacity short increased by 18 percent from 2003 with a significant increase in non-spin capacity short and a corresponding decrease in regulation down capacity short. Overall though, 2004 suffered from greater bid insufficiency than 2003. In terms of the number of hours in which shortages were present, the same pattern prevailed. Bid sufficiency in regulation down improved, but deteriorated in the other three services, especially in non-spin.

Table 4.2 Bid Sufficiency 2003 – 2004

Year	Total Capacity Short in MW				
Service	RU	RD	SP	NS	TotalCapacityShort
2003	6,172	11,333	11,932	4,290	33,726
2004	7,310	4,519	15,641	12,338	39,809
Percent	18%	-60%	31%	188%	18%
	Number of Hours in which a Shortage of any magnitude existed				
Service	RU	RD	SP	NS	TotalHoursShort
2003	168	389	344	100	1,001
2004	408	137	556	462	1,563
Percent	143%	-65%	62%	362%	56%

Figure 4.13 Bid Insufficiency by Capacity and Hour