Chapter 6.
Market Inter-Relationships

6.1 Background

6.1.1 Chapter Overview

This chapter describes the inter-relationships among California's various markets for energy and ancillary services. Section 6.1.2 provides a brief overview of market inter-relationships. Section 6.2 discusses relationships between the ISO real-time energy market and the PX forward energy markets. Section 6.3 discusses relationships between the ISO ancillary services markets and the PX forward energy markets. The reader may find it helpful to refer to Figure 2-3 in Chapter 2, which provides a time sequence of key events in the operation of the day-ahead, hour-ahead, and real-time markets.

6.1.2 Markets, Arbitrage, and Decentralized Optimization

The underlying approach adopted in restructuring California's electric industry was to replace centralized optimization, based on iterative numerical algorithms, with a process of coordinated decentralized optimization. This new process relies on iterative market clearing and arbitrage by market participants among the various energy and ancillary service markets. Under this market-oriented approach, each participant tries to optimize the use of its generation resources among the markets. Overall optimization is achieved through a learning process, in which participants engage in standardized interactions with the ISO, the PX and other market participants, and respond to prices, transmission constraints, and other market signals. The process relies upon prompt dissemination of non-proprietary market information by the ISO.

Within this market structure, the outcomes in the various ISO and PX markets are strongly inter-dependent. The sequential nature of these markets, in terms of both their temporal relationship to the actual trading hour (day-ahead, hour-ahead, and real-time) and the order in which they are cleared (PX energy, followed by ISO A/S, etc.), increases the range of possibilities for arbitrage by market participants compared to the centralized optimization approach, and also provides some defining structure to these arbitrage possibilities.

In centralized optimization, the mathematical optimization process imposes strict relationships among the markets and helps determine the relationships among prices for different products. In a market-oriented approach such as California's, description of price and quantity relationships across the markets depends on techniques such as analysis of historical data, application of behavioral models, and evaluation of assumptions regarding arbitrage among markets under equilibrium conditions.

6.2 ISO Real-time and PX Energy Markets

6.2.1 Background

California's market design does not impose any explicit penalties on generators or loads for any real-time deviations from the final schedules accepted by the ISO prior to each operating hour. Any deviation from scheduled supply or demand is settled at the hourly real-time imbalance price. Those SCs providing extra supply (or having lower than scheduled demand) earn this price, while those having extra demand (or providing lower than scheduled supply) pay this price. Thus, the ISO's imbalance market is, in practice, the only real, physical market for energy, upon which all financial settlements are ultimately based, and thus represents a *spot market* for energy.

Under efficient market conditions, in which buyers and sellers can arbitrage between the forward and real-time energy markets, prices in the PX forward energy and the ISO real-time energy markets should not differ significantly for an extended period of time. From the perspective of an individual buyer, however, several additional factors may be considered when deciding how much energy to procure through each of the markets:

- **Price Impacts of Shifting Demand Between Markets.** The ability of buyers to shift demand from the PX forward market to the real-time market currently provides the only significant source of demand flexibility in the energy markets. When large buyers face a steeply upward sloping supply curve in the PX market, they can often lower the PX price by shifting a portion of their expected demand into the real-time market, and thus limit their exposure to high day-ahead energy prices and lower their total costs. Even if the price in the real-time market exceeds the final, market clearing price in the day-ahead market, the higher real-time price is only applied to a relatively small portion of the buyer's total demand, while the lower day-ahead price is applied to the bulk of the buyer's demand.

- **Billing of A/S Based on Scheduled Demand.** During the first year of operation, an additional incentive for shifting load into the real-time market was created by the ISO's practice of billing A/S costs to SCs based on their *scheduled* rather than their *metered* loads. In effect, this practice has placed an additional cost upon energy purchased and scheduled through the day-ahead market that is not applied to energy purchased in the real-time market. This practice has given load schedulers an incentive to shift some of their procurement from the day-ahead market to the real-time market as a way to avoid paying A/S costs. As discussed in Chapter 3, A/S costs per MWh of load have averaged over 10 percent of the total energy cost in the PX day-ahead market. During the summer months A/S costs per MWh of scheduled load averaged between 12 and 15 percent of the cost of energy in the day-ahead market.

- **Price Volatility**. From the perspective of some buyers, the lower volatility of PX day-ahead prices relative to real-time prices may warrant a price premium for power purchased in the day-ahead market.

6.2.2 Comparison of Real-time and PX Day-ahead Energy Prices

Over the first year of operation, differences between prices in the real-time and the day-ahead markets have varied widely from hour-to-hour and month-to-month. Figures 6-1 and 6-2 display the differences between the monthly average prices in the two markets, for each month of the first year of operation, demonstrating a very clear seasonal pattern. The average monthly prices used in these figures are provided in Figure 6-4.[1] Figure 6-3 is a histogram of the differences between day ahead and real time hourly prices for all hours of the first year of operation. Figures 6-5 and 6-6 show differences in the daily average peak and off-peak prices in the real-time and PX markets.

Salient patterns in this comparison of real-time and PX prices are summarized below:

- During the first four months of market operation, real-times prices were significantly lower than PX prices, as the ISO typically needed to decrement supply in real time to mitigate over-generation. Over this period, average real-time prices were about 19 percent lower than PX prices. Even in July, when peak summer loads occurred and price spikes appeared in the real-time market, average hourly real-time prices remained 13 percent lower than PX prices.

- In contrast to the previous pattern, in the months of August through November real-time prices exceeded prices in the PX day-ahead market by 15 percent.

- Since October 1998, prices in the two markets have tracked much more closely, with average real-time prices just 2 percent below average PX prices.

The last pattern may be an indication that market participants have improved their ability to respond to price differences and arbitrage between them since the market opened. The possible trend toward improved arbitrage between the real-time and PX markets is illustrated in more detail in Figures 6-5 and 6-6. These figures show that the difference in prices in the two markets resembles a *mean reverting process*, in which any significant differences in prices tends to revert toward zero on a day-to-day basis. Although the differences between real-time and PX prices exhibit this mean-reverting pattern for the entire 12 month period, the *average* difference in prices, toward which prices revert, has changed over time. As noted above, real-time prices were systematically *lower* than PX prices in the first few months of operation, and systematically *higher* than the PX prices from August through November. Since November the difference in prices has been close to zero, with day-to-day differences being smaller and lasting for shorter periods of time. It should be noted, however, that having only a single year's market data makes it impossible to distinguish learning trends from seasonal trends or other longer-cycle factors affecting relative prices.

Figure 6-3 shows that the first year's hourly differences between prices in the two markets have been distributed quite symmetrically. The average annual prices in these two markets were virtually equal over the first 12 months of operation, as shown also in Figure 6-4.

[1] All comparisons are made in terms of simple hourly averages, i.e., not weighted by sales volumes in either market.

Figure 6-1. Comparison of Monthly Average Real-time and PX Prices

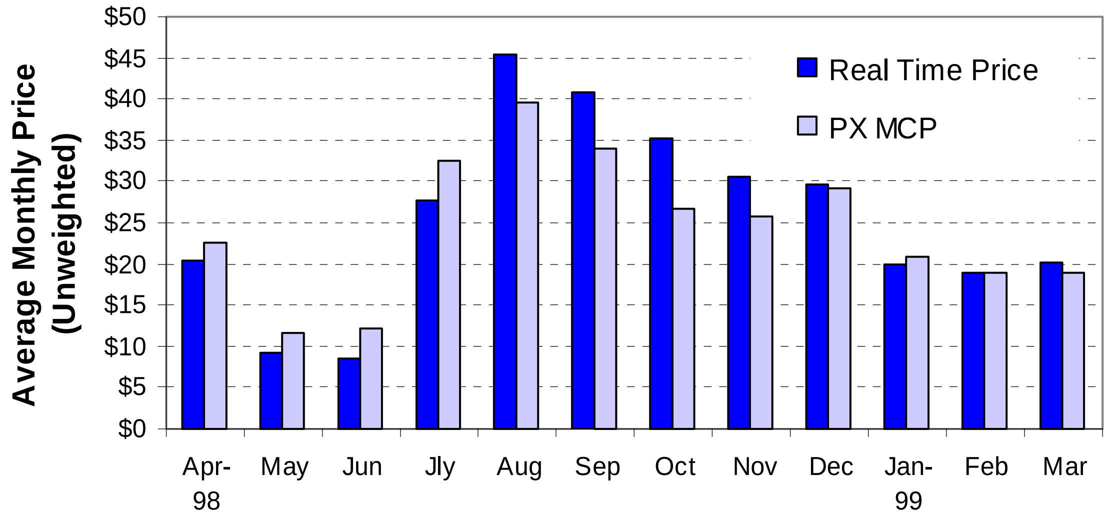


Figure 6-2. Percentage Differences Between Monthly Average Real-time and PX Prices

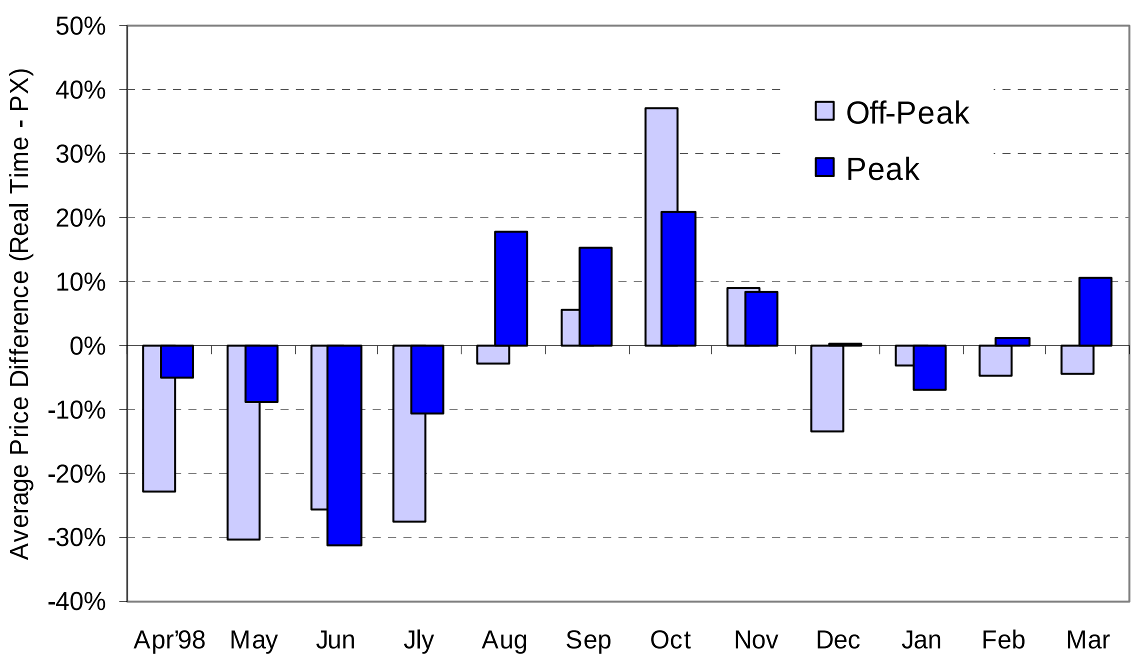
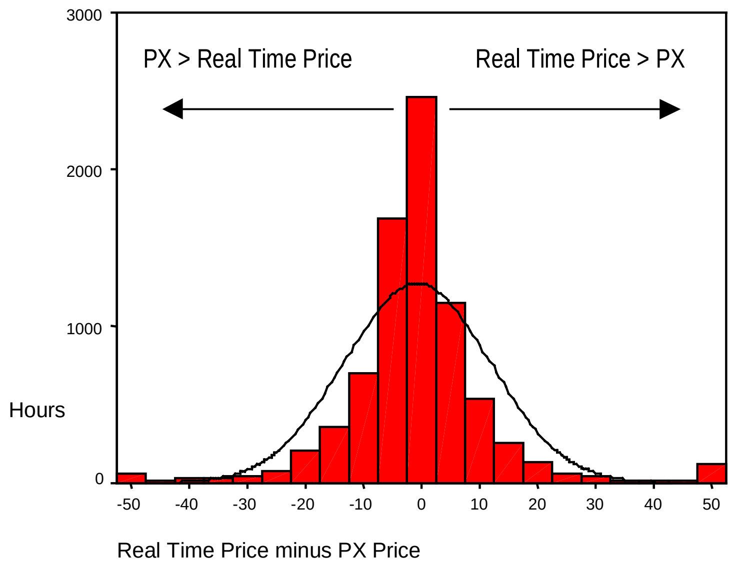


Figure 6-3. Differences in Hourly Real-time and PX Prices



Note: Histogram shows values less than -$50 as -$50, and values greater than $50 as $50.

Figure 6-4. Monthly Average Real-time and PX Prices

Month	Real Time	PX	Difference	
April	$20.34	$22.62	-$2.28	-10%
May	$9.80	$12.05	-$2.26	-19%
June	$8.38	$12.30	-$3.92	-32%
July	$27.69	$32.86	-$5.17	-16%
Aug	$44.19	$39.57	$4.62	12%
Sept	$37.14	$33.50	$3.64	11%
Oct	$30.45	$25.42	$5.03	20%
Nov	$26.46	$24.47	$1.99	8%
Dec	$27.38	$28.10	-$0.72	-3%
Jan	$19.60	$21.35	-$1.74	-8%
Feb	$18.98	$19.19	-$ .21	-1%
Mar	$20.09	$18.83	$1.27	6%
Total	$24.21	$24.19	-$ .02	0%

Figure 6-5. Differences between Daily Average Real-time and PX Prices (Peak Hours 7-22)

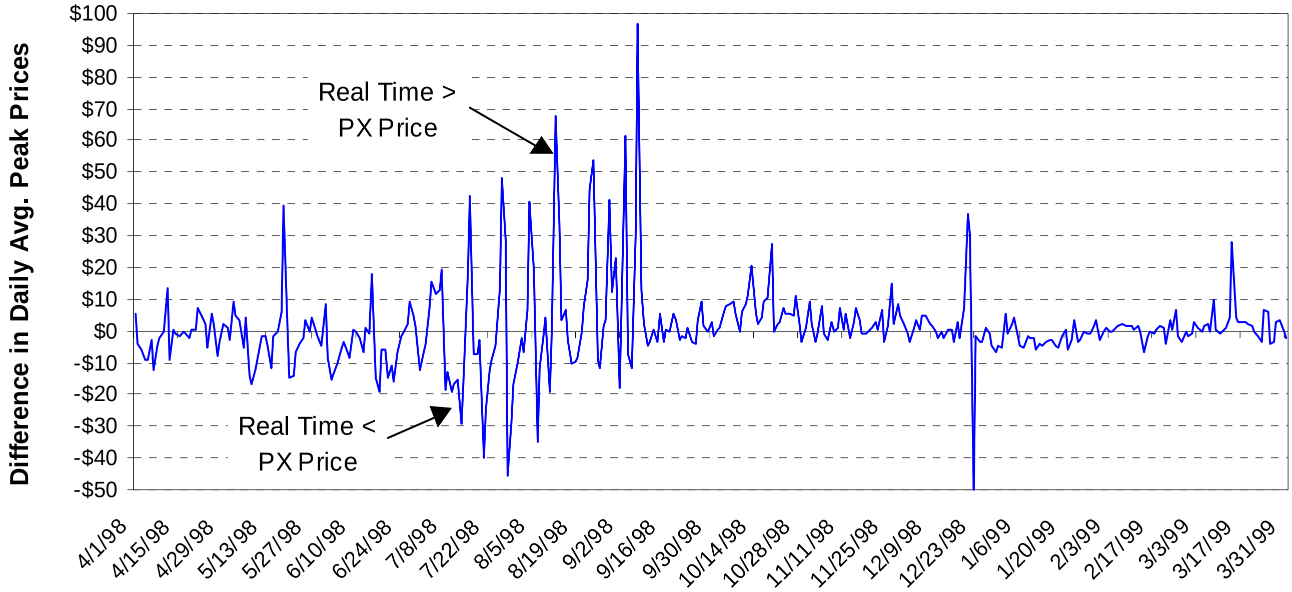
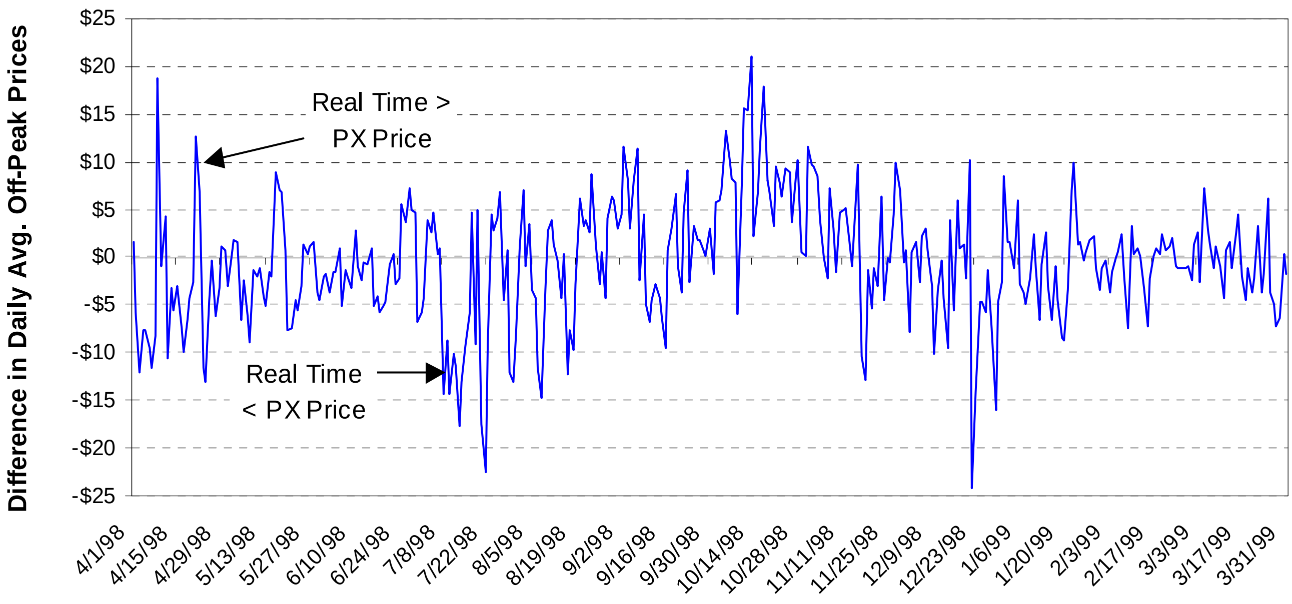


Figure 6-6. Differences in Daily Average Real-time and PX Prices (Off-peak)



6.3 PX Energy and ISO Ancillary Services Markets

6.3.1 Competitive Benchmarks for the Ancillary Services Markets

To assess the performance of the ISO's ancillary services markets, it is necessary to develop a benchmark of A/S prices and costs under efficient, competitive market conditions. One important benchmark of the competitiveness and efficiency of any industry is the relation of prices to the cost of service. Assessing the cost of providing A/S, however, presents a challenge for several reasons.

- First, no comparable markets for A/S exist which may be used as a benchmark for either the prices or the overall system costs of A/S. Under traditional utility planning, A/S were treated as a byproduct or a bundled component of overall energy service. In California's markets, prices for A/S are driven by both the direct costs of providing these services and the indirect opportunity costs of providing A/S instead of energy in the forward markets

- Second, determining the costs to individual generating units of providing A/S is complicated by the fact that most units provide both energy and A/S. An estimate of the cost of providing A/S is therefore highly sensitive to the assumptions used to allocate startup costs and annual fixed costs to these two markets. As with energy, many of the costs associated with providing A/S depend on prices and operating levels during the daily or weekly periods over which units may be committed to the different markets.

Despite the difficulties in assessing the costs of A/S, the relationship between A/S capacity costs and energy prices provides a key benchmark by which A/S prices may be assessed. The following sections outline key drivers likely to affect the relationship between energy and A/S prices in an efficient, competitive market.

6.3.2 Direct and Indirect Cost of Supplying Ancillary Services

The supply of A/S is composed of both *infra-marginal* units, with variable operating costs *below* market energy prices, and *super-marginal* units, with variable operating costs *above* market energy prices. The costs facing these units are illustrated in Figure 6-7.

Infra-marginal units, with variable operating costs below market energy prices, face an indirect opportunity cost if they provide A/S. For these units, the opportunity cost of providing A/S capacity is the foregone revenue of providing energy in the forward energy markets. It should be noted, however, that under California's market structure, units providing A/S can still submit separate bids for supplemental energy in the ISO's real-time imbalance market. Thus, the opportunity cost of not providing energy in the forward energy markets may be offset by sales of energy in the ISO's real-time market.

For super-marginal units, with operating costs higher than market energy prices, the costs associated with providing A/S stem from the fact that in order to provide A/S, these units must typically be already operating at minimum levels. For these units, the direct variable cost of providing A/S is a function of their variable operating costs relative to PX energy prices, minimum load levels, and ramping rates. An illustrative example of these direct costs is provided in the following section. Since these units have higher operating costs, there is typically less opportunity for these units to earn additional revenues from sales of energy in the real-time market. However, for hours when prices do rise in the real-time market, revenues from real-time energy sales do represent another source of revenue that can offset the cost of providing A/S capacity.

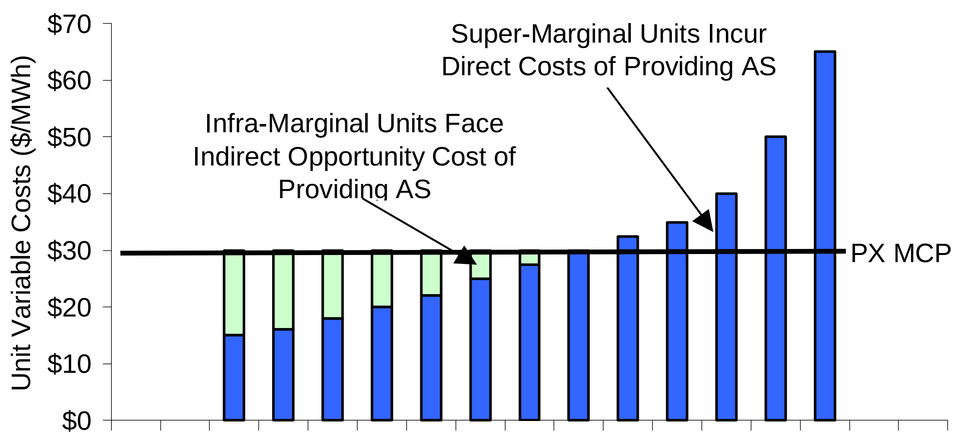
Under many conditions, the opportunity costs associated with providing A/S are significantly lower for individual units than the market energy prices, and may approach zero. For instance, during shoulder and off-peak hours, many thermal units ramp down to minimal operating levels, with the expectation of ramping back up to provide energy during subsequent hours or days when energy prices are higher. During these hours there are no real foregone opportunities for these units. To give another example, an important source of supply for A/S are combustion turbine peaking units. With startup times of 5 minutes or less and relatively low startup costs, they can provide Non-spinning and Replacement Reserves without actually being in operation. For these units, the variable operating cost of providing Non-spinning and Replacement reserve is likely to be minimal and may approach zero.

Two important exceptions to these simplified considerations include the following:

- The cost of providing Upward and Downward Regulation may be increased due to required modifications to a unit's operating level to enable it to provide these services, as well as additional operating costs associated with wear and tear.

- For hydro units, with storage capacity or other special constraints on water releases over different time periods, the opportunity cost of providing A/S in a given hour may depend on energy and A/S prices in other time periods. Optimizing use of these resources requires a careful consideration of how providing energy or A/S in one time period effects each unit's ability to provide energy or A/S in another time period.

Figure 6-7. Direct and Indirect Costs of Providing Ancillary Services



6.3.3 Illustration of the Relationship Between Energy and Ancillary Service Prices

As described above, the cost of supplying A/S involves both direct costs and indirect opportunity costs. This section illustrates how forward market energy prices are likely to be a key driver of both the direct and indirect costs of providing A/S, and presents a simplified example to illustrate the expected relationship between prices in these different markets.

For units with variable operating costs below forward energy prices, the foregone revenue from not providing energy is an opportunity cost associated with providing A/S capacity. Suppliers can be expected to factor this cost into their bidding decisions in both the energy and A/S markets. Figure 6-8 illustrates the opportunity cost of providing A/S for a unit with a variable operating cost of $20, during hours when the energy MCP is $30. In this example, the unit's opportunity cost associated with providing A/S is the difference between the energy MCP and the unit's variable operating cost, or $10. If efficient arbitrage exists between the energy and A/S markets, the unit could be expected to participate in the A/S market if A/S capacity prices clear above $10.

For a unit with variable operating costs higher than energy prices, the direct cost of providing A/S is a function of the unit's operating characteristics, as well as the difference between its variable operating costs and the energy MCP. Figure 6-9 below shows how the direct cost of providing A/S can be calculated on an hourly basis, based on these factors.

Figure 6-10 shows how, for this unit, the direct cost of providing A/S declines as the PX energy price increases. For hours in which the energy price exceeds the unit's variable operating costs, the direct cost of providing A/S becomes negative, reflecting the positive net revenues earned from sales of the energy produced at its minimum operating level. During these hours, the minimum price at which the unit would continue to provide A/S is driven not by the unit's direct operating costs, but by the indirect opportunity cost of foregone revenues from sales in the PX energy market.

Figure 6-11 uses the same data as in Figure 6-10 to depict the expected relationship between energy and A/S prices in a market where the unit in this example was the marginal supplier. As shown in Figure 6-11, the cost of providing A/S is higher at very low energy prices ($10 to $15), but drops as the energy price increases. As the price rises above the marginal costs of supply, the opportunity cost of providing A/S rises in tandem with the energy price. However, as energy prices rise, the difference between energy and A/S costs remains at $30. In this example, the $30 difference is equal to the unit's variable operating cost, which represent the difference in energy and capacity prices at which the supplier would earn the same net revenues, and would have no incentive to arbitrage between markets.

Figure 6-8. When PX Prices Exceed Variable Energy Costs, Ancillary Service Prices Should Reflect Opportunity Cost of Not Participating in Energy Markets

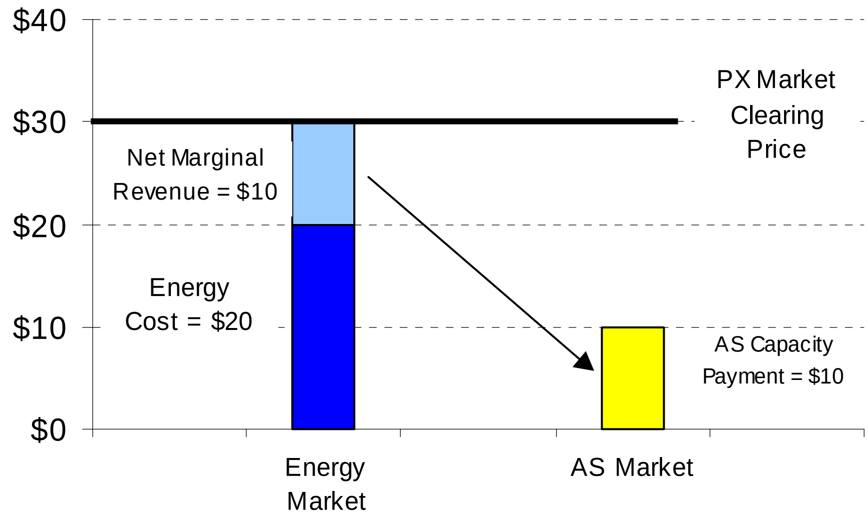


Figure 6-9. Illustrative Example of the Cost of Providing A/S

Maximum Generating Capacity	160 MW
Minimum Operating Level	40 MW
Ramp Rate	6 MW/min.
Variable Cost	
Minimum operating level	$40/MWh
Maximum operating level	$30/MWh
Potential Ancillary Service Capacity	
Spin and Non-spin	60 MW
Replacement Reserve	120 MW

Direct variable cost of spinning reserve
@ $25 energy price = $10

$$\frac{40\text{ MW x (\$40 - \$25 PX Price)}}{60\text{ MW Spinning Reserve}}$$

Figure 6-10. Effect of PX Prices on Ancillary Service Costs for a Unit with $30 Operating Cost

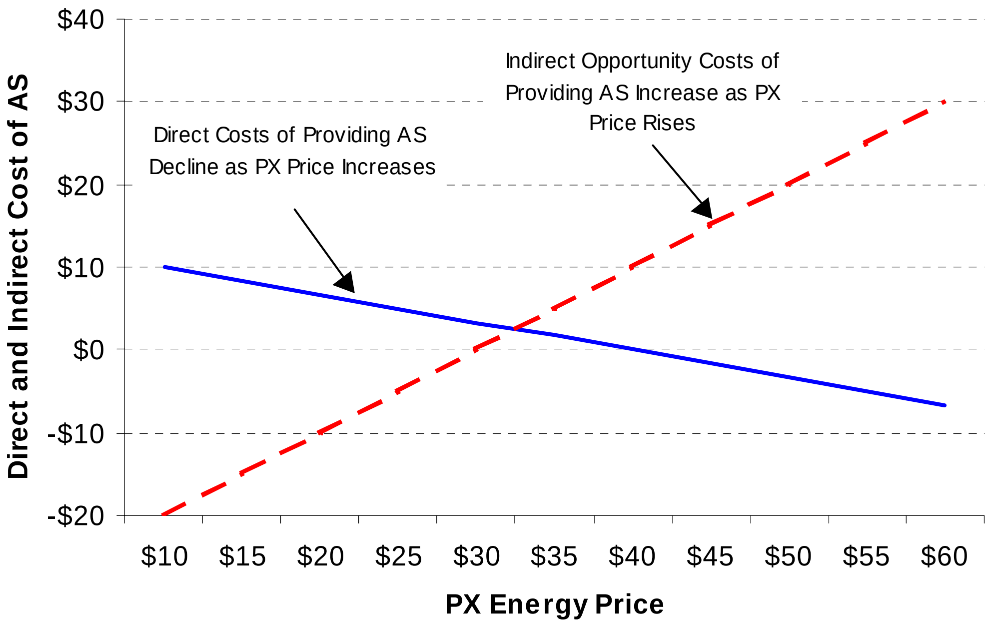
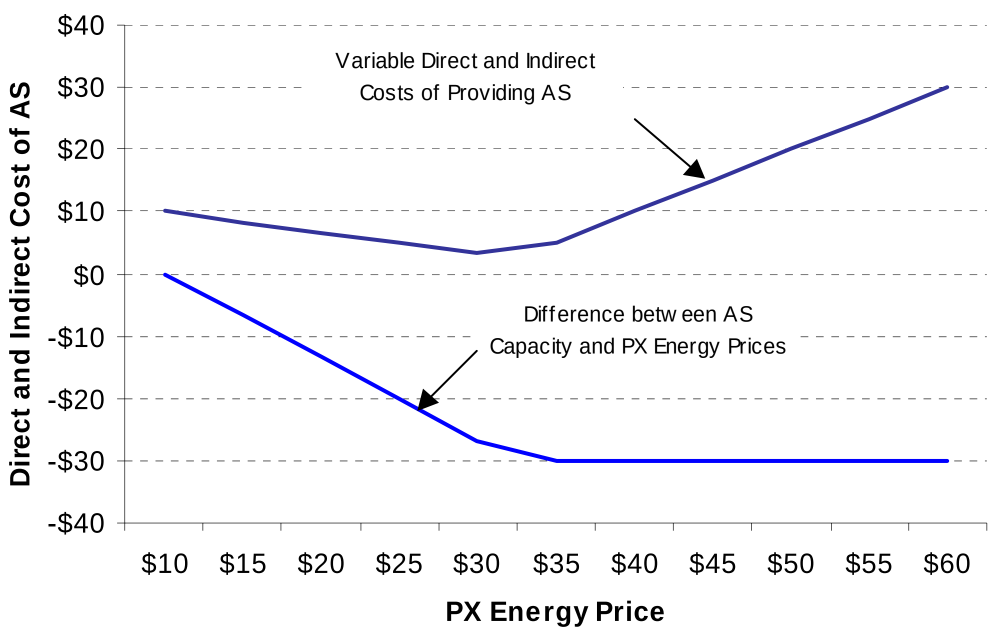


Figure 6-11. Relationship Between Ancillary Services Costs and PX Prices



6.3.4 Comparison of A/S Capacity and PX Energy Prices

This section compares prices in the ISO's different A/S markets to energy prices in the PX market. The analysis focuses on the difference in prices for capacity versus energy, in order to assess the extent to which prices in these two markets reflect supply costs and the ability of suppliers to arbitrage between markets.

Figure 6-12 compares average A/S prices to market clearing prices for energy in the PX market. Figures 6-13 through 6-15 provide histograms of the difference between hourly PX energy and A/S prices for each of the A/S during the ISO's first year of operation.

Figure 6-12 also provides averages for "trimmed" data, to illustrate the effect on average prices in hours when A/S capacity prices exceeded PX energy prices due to spikes in the A/S markets. Regulation capacity prices (including REPA payments when REPA was in effect) that exceeded the PX MCP by more than $100 were "trimmed" by setting these prices equal to the PX MCP. As shown in Figures 6-13 and 6-14, the relatively small number of hours when Regulation prices exceeded PX prices by $100 represent outliers, i.e., instances when the difference between Regulation and PX prices departed from an otherwise normally distributed pattern.

For all other A/S, capacity prices exceeding the PX energy price were trimmed by setting these prices equal to PX energy price, to reflect the fact that in efficient, competitive markets prices for capacity should not exceed prices for energy. As shown in Figure 6-12, trimming A/S price data in this manner provides an indication of how price spikes that occur in a relatively small number of hours have a significant affect on average prices and overall costs in the A/S markets.

Figure 6-12. Comparison of A/S and PX Market Clearing Prices

	A/S Market Clearing Prices		Difference in AS Capacity and PX Energy Price [2] (A/S MCP – PX MCP)	
	Weighted Average	Trimmed Mean [1]	Weighted Average	Trimmed Mean
Regulation + REPA (5/20/98 – 11/27/98)[3]	$62.81	$35.48	+ $34.17	+ $6.72
Regulation MCP (11/28/98 – 3/31/99)	$19.57	$16.68	- $ 3.24	- $ 5.83
Spinning Reserve (4/98 – 3/99)	$18.66	$ 8.83	- $ 7.56	- $17.78
Non-Spinning Reserve (4/98 – 3/99)	$10.71	$ 7.05	- $15.25	- $19.69
Replacement Reserve (4/98 – 3/99)	$10.80	$ 6.44	- $13.46	- $17.86

[1] For Regulation the prices (including REPA, when in effect) that exceeded the PX MCP by more than $100 were set equal to PX MCP +$100. For all other A/S, capacity prices exceeding the PX energy price were set equal to PX energy price. All prices were weighted by total A/S market purchases for each hour.

[2] Averages in table on difference in A/S capacity and PX energy price for each hour (PX MCP – AS MCP). Values trimmed as described in note 1 above.

[3] For periods when REPA was in effect, the effective Regulation price for each hour equals Regulation MCP + Maximum ($20, Real-time Imbalance Energy Price).

Figure 6-13. Relationship of Regulation and PX Energy Prices (with REPA, May 20 to Nov. 27, 1998)

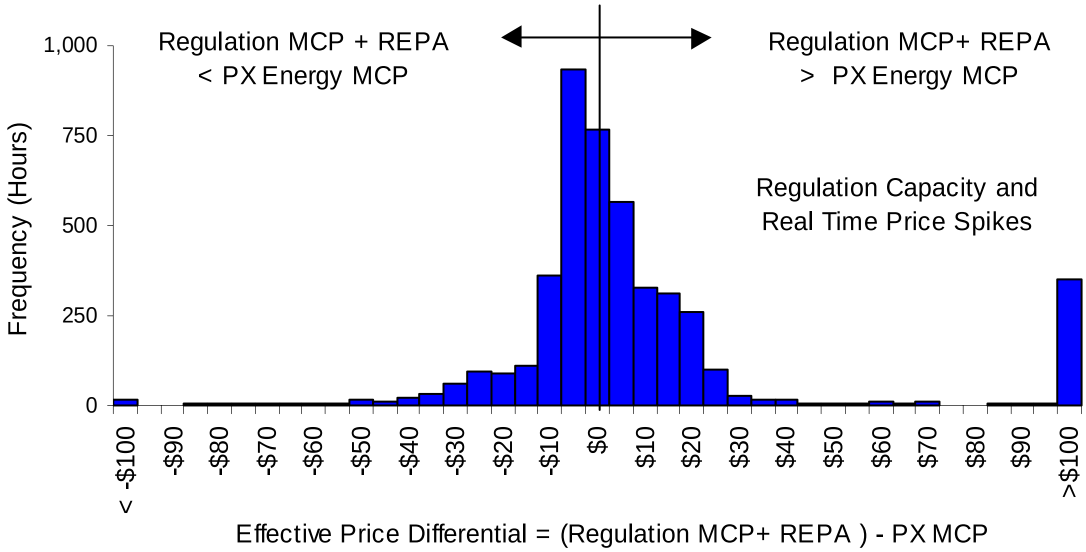


Figure 6-14. Relationship of Regulation and PX Energy Prices (without REPA, Nov. 28, 1998 to March 31, 1999)

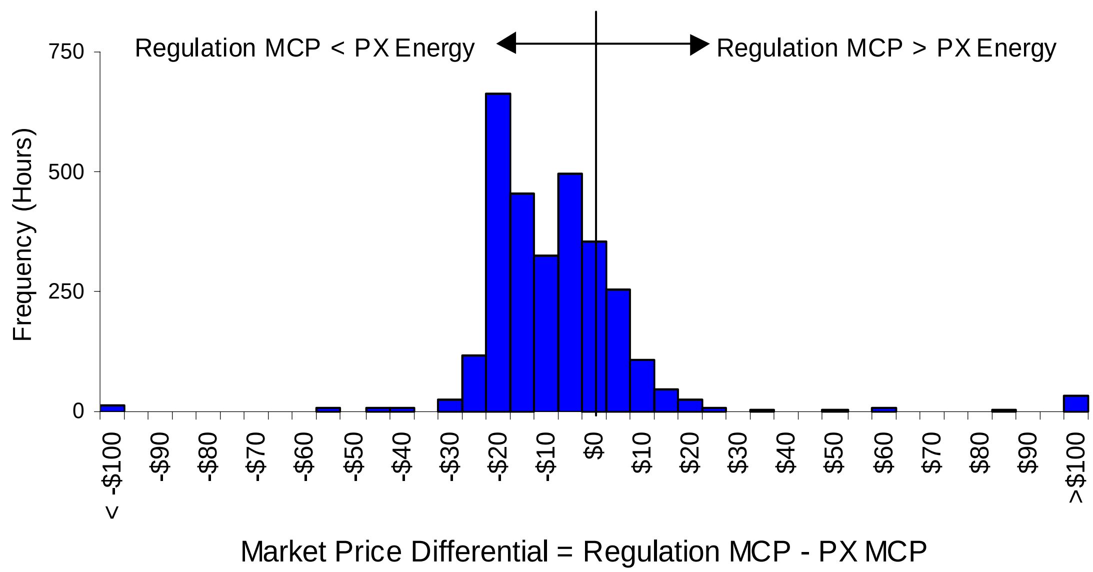
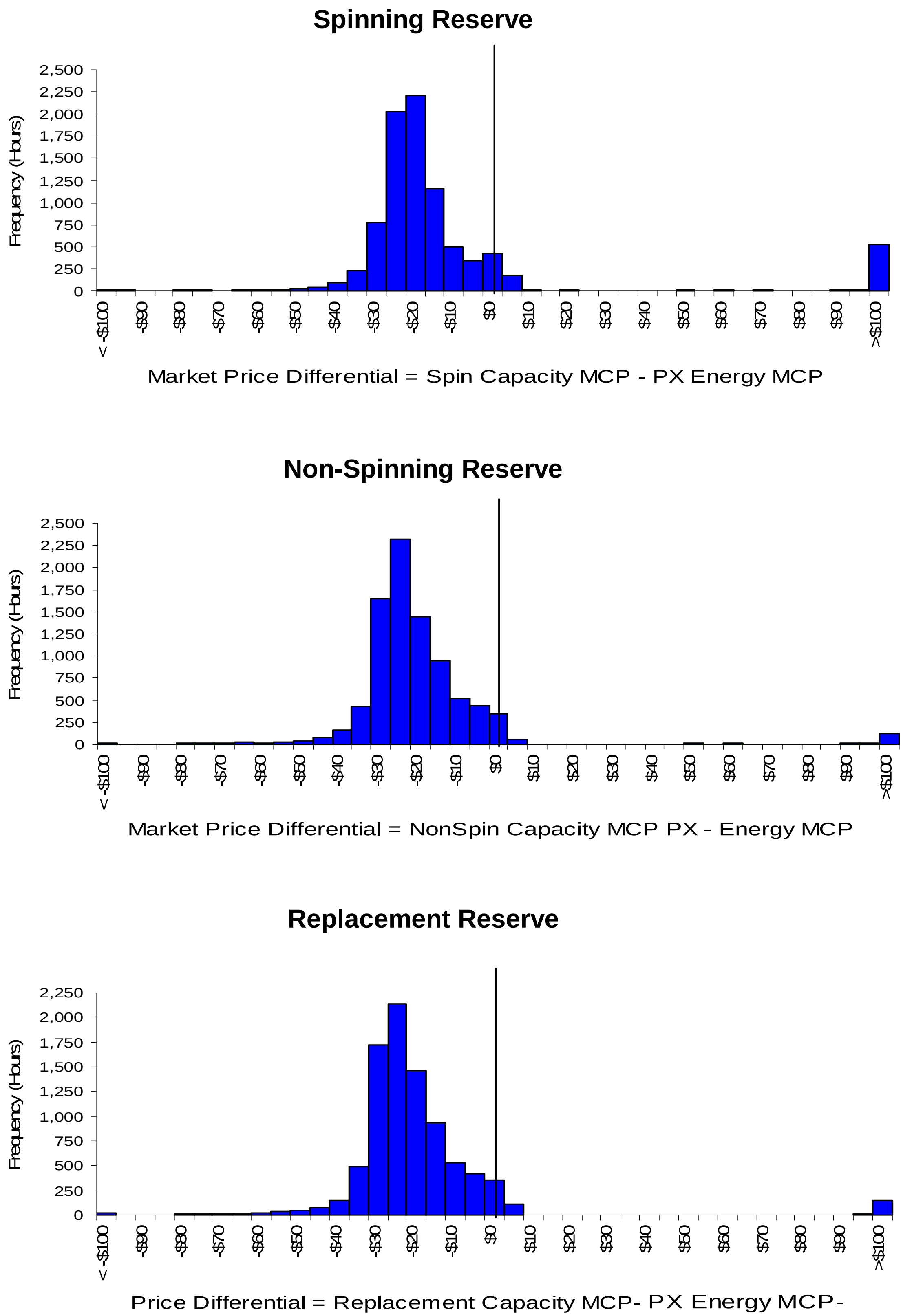


Figure 6-15. Other Ancillary Service Capacity and PX Energy Prices (April 1998 to March 1999)



As shown in the preceding figures:

- The prices of Regulation (including REPA payments when in effect) have frequently exceeded the price of energy by $10 to $30, particularly when REPA was in effect. During price spikes, however, Regulation prices have exceeded PX prices by $100 or more.

- While REPA was in effect, Regulation prices were on average nearly $34 higher than PX energy prices. It should be noted that, since REPA payments are based on real-time energy prices and are paid in addition to capacity payments, the effective price for Regulation frequently exceeded the $250 price cap placed on the real-time energy and other A/S markets. Based on trimmed data, which reduces the effect of price spikes on average prices, Regulation prices while REPA was in effect were about $7 higher than energy prices.

- After removal of REPA, Regulation prices were on average about $3 lower than PX energy prices. Based on trimmed data, which reduces the effect of price spikes on average prices, Regulation prices since REPA have been about $6 less than energy prices.

- Higher average prices for Spinning Reserve are primarily a result of the fact that more price spikes occurred in this market than in the markets for Non-Spinning or Replacement Reserve. As shown in Figure 6-12, average prices for Spinning Reserve are just slightly higher than prices for lower quality A/S, once data are trimmed to reduce the effects of price spikes on average prices.

- In other A/S markets, the differences in A/S capacity and energy prices during many hours reflect the $20 to $30 marginal operating costs of many units. After trimming the data to remove the effects of price spikes, the difference between A/S capacity and PX energy prices was about $17 to $20 in each of these markets.

6.3.5 Scenario Analysis of Ancillary Service Costs

This section presents a series of scenarios designed to assess the sensitivity of A/S costs to changes in the structure and efficiency of the ISO's A/S markets. The scenarios also provide benchmarks for assessing the future performance of the A/S markets. For this analysis, total A/S costs were calculated as a percentage of total energy costs for three scenarios, representing the range of factors that could cause this ratio to increase or decrease. For each scenario, total energy costs were calculated by multiplying the PX market clearing prices by the actual ISO load for each hour.

1. **Actual First Year Costs.** This scenario is based on estimated actual A/S costs for the ISO's first 12 months of operation.

2. **First Year Costs Without Cost-Based Rate Caps.** This scenario is intended to provide an upper bound on A/S costs, by estimating what they would have been under the past year's market conditions, with the FERC cost-based A/S price caps eliminated for all participants. For this scenario, actual market clearing prices were simply multiplied by the actual market clearing quantities for each hour of the first operating year. For this calculation, prices above the current $250/MW price cap, which occurred during several days in July, were set at the

cap.[2] The result of this scenario is that the overall cost of A/S would rise by more than 20 percent above Scenario 1. The increase in total A/S costs under this scenario reflects the fact that the cost-based caps were in effect during the summer months of 1998, when relatively high prices occurred, thus reducing dramatically the actual prices paid for A/S capacity.

3. **Efficient Arbitrage Between A/S Capacity and PX Energy Markets.** For this scenario, all historical market clearing prices for A/S capacity over $100/MW were constrained to be no more than $10 above the price of energy in the day ahead PX market. This scenario represents the fact that in efficient markets, in which suppliers arbitrage between the various energy and A/S markets, prices for capacity typically should not exceed prices for energy (which typically include actual energy costs, as well as a component for recovery of capacity costs). It should be noted that this scenario does not assume *perfectly competitive* markets. It merely assumes a *more efficient* market in terms of the ability of suppliers to arbitrage between markets, so that prices in the energy and capacity markets can equilibrate to levels which result in comparable net revenues for suppliers. This scenario is designed to highlight the effect of merely eliminating the number of cases in which A/S prices were extremely high and exceeded energy prices in the PX market by significant amounts. The scenario does not assume any change in prices during periods when prices were high in both markets, i.e., when A/S capacity prices did not exceed energy prices by more than $10.

Figures 6-16 and 6-17 illustrate the effect of the Scenario 3 assumptions on the annual A/S price duration curves.

- As shown in Figure 6-16, less than 10 percent of the total amount of Regulation capacity purchased by the ISO accounted for the bulk of total Regulation costs over the ISO's first 12 months of operation. About 8 percent of the Regulation purchased by the ISO was during hours when the price exceeded PX energy prices by $10 or more. Assuming that Regulation Reserves could be purchased for no more than a $10 premium over energy prices during these hours, total costs of Regulation would be reduced by nearly 50 percent.

- The price duration curves for other A/S are similarly skewed, with extremely high prices during hours when less than 5 percent of total A/S service capacity was purchased. Figure 6-17 provides a price duration curve for Replacement Reserve, which was typical of the other A/S, along with the hypothetical curve that would have resulted if Replacement capacity prices never exceeded PX energy prices by more than $10.

Figure 6-18 and 6-19 compare total A/S costs under the three scenarios. A comparison of Scenarios 1 and 2 shows that a significant reduction in A/S prices from first year levels would be required merely to compensate for the fact that all suppliers are no longer subject to cost-based caps and are paid the market clearing prices. Comparison of Scenarios 1 and 3 shows that A/S costs could be limited to within 10 percent of total energy costs if no major spikes occurred where A/S capacity prices greatly exceeded energy prices.

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[2] It should be noted that if the $250/MW price caps were not in affect during the peak summer period, the cost impact of paying market clearing prices for capacity during high-price hours may have been substantially offset by a decrease in prices due to additional supply being offered in those hours.

Figure 6-16. Regulation Price Duration Curve

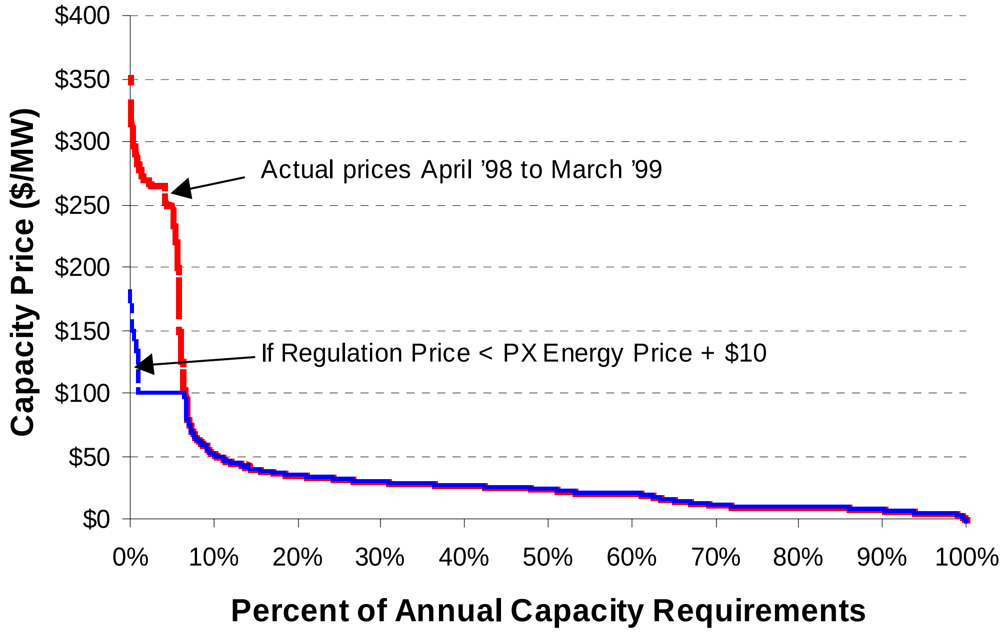


Figure 6-17. Replacement Reserve Capacity Price Duration Curve

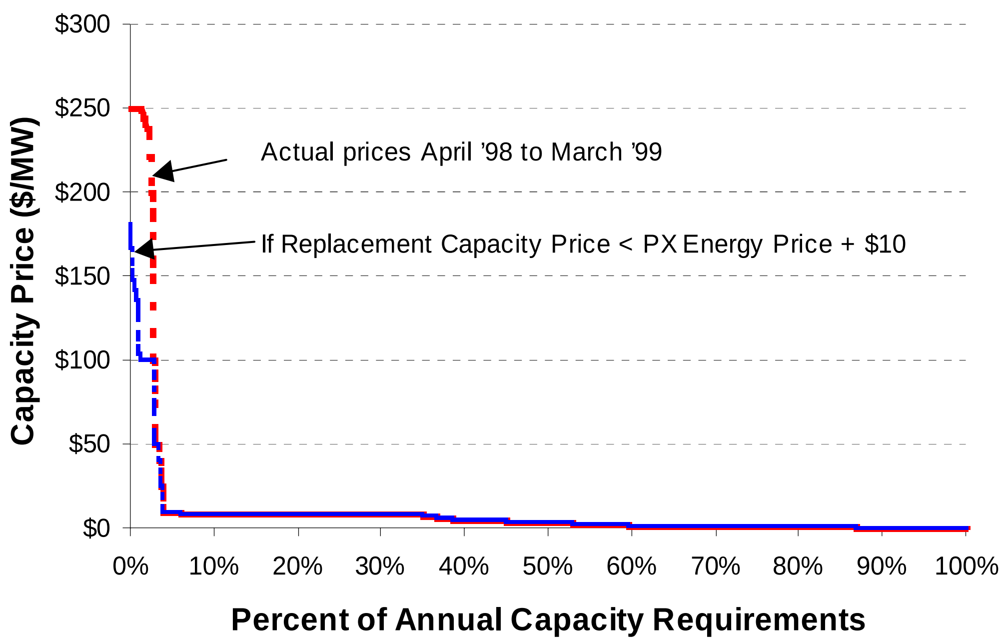


Figure 6-18. Annual Comparison of A/S Cost Scenarios

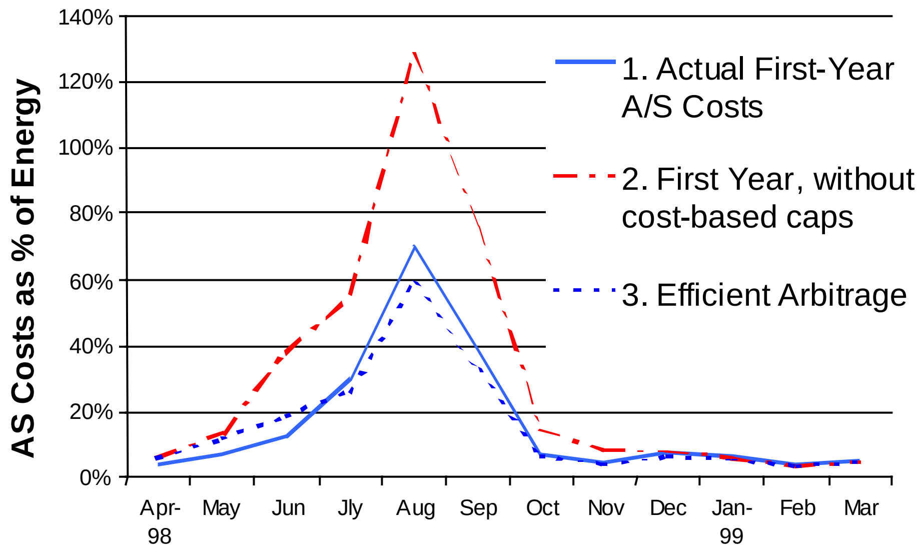
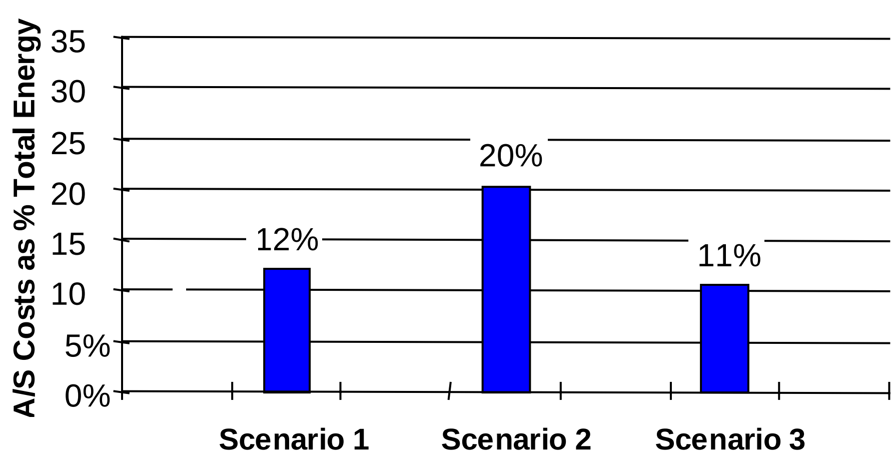


Figure 6-19. Annual Comparison of A/S Cost Scenarios



6.4 Rate Caps and Alternatives

As price caps are lifted there may be a need to implement alternative mechanisms to guard against extreme and sudden price spikes. All markets need to protect against the proverbial billion dollar bid being accepted. In anticipation of the raising of the present caps, the MSU is considering various types of "circuit breaker" mechanisms similar to those used in the stock and commodity markets to limit extremely large and rapid swings in prices. For example, a possible type of circuit breaker in the energy and A/S markets would automatically raise the existing cap level by a pre-specified amount after it has been hit two days in a row. Successive hits would continue to bump the cap up, but at a slower rate than if there were no controls. This mechanism would give buyers an opportunity to protect themselves against sudden swings by limiting the amount the price could move in a two-day period. The MSU believes mechanisms such as this will be an important factor in increasing the demand elasticity of the ISO's markets, without deterring new investment since prices will still be able to rise as a result of shortages. Such a mechanism could serve both as a way to transition out of the current price cap regime without suddenly eliminating the cap, and as an ongoing way to moderate price volatility in the markets. As the circuit-breaker levels are hit and price caps are lifted, the MSU will be able to assess the relative impacts of market manipulation and true supply shortages on market prices.

6.5 Reliability Must-Run Contracts

During the ISO's first summer of operation, we identified a number of incentives inherent in Reliability Must-Run (RMR) contracts that encourage withholding or bidding of capacity at very high prices in the energy and ancillary service markets. RMR contracts were modified during the subsequent fall and winter months to remove these incentives and minimize the impact of RMR contracts on other markets. This section describes the negative market impacts of RMR contract structures during the first year of operation, and how RMR contracts have since been modified to minimize these negative impacts.

6.5.1 Market Impacts of Existing RMR Contracts

Three forms of RMR contracts, commonly referred to as Contracts A, B and C, existed during the ISO's first year of operation:

- Under Contract A, when a unit was called upon to operate at a specific level to maintain system reliability requirements, it received a variable cost payment based on its variable operating costs, any applicable start-up costs, plus a *Reliability Payment* that covered a portion of its fixed costs. The Reliability Payment was intended to enable units to recover fixed costs over the course of a year, but was paid on a per MWh basis only when units provide energy in response to an RMR dispatch notice.

- Under Contract B, the ISO paid 100 percent of the fixed costs of a unit to the owner up front, in monthly *Availability Payments* not associated with specific calls on the unit for reliability services. A unit under Contract B was then reimbursed only for variable operating costs and startup costs (if applicable), whenever it was not scheduled through the day-ahead energy market and was called upon to provide energy to maintain reliability pursuant to an ISO dispatch notice. When a unit under Contract B was not called upon for reliability services, or when it had capacity available in excess of the ISO's reliability requirements, it was able to participate in the market, but its owner was required to credit back 90 percent of the profits so earned against the fixed-cost payments received from the ISO.

- Under Contract C, the owner received full fixed costs but earned no market revenues from the RMR unit. A unit was dispatched only when needed to meet RMR requirements, with the owner being reimbursed for variable operating costs each time it was dispatched. In 1998 no units were under Contract C, but as of March 1999, 596 MW of RMR capacity were under Contract C.

The structures of both Contract A and Contract B create incentives for unit owners to withhold capacity or bid very high in the PX day-ahead market. The first problem was that the owner of a Contract A unit that was entitled to a relatively high Reliability Payment faced an *opportunity cost* of winning in the PX day-ahead market (which is cleared before the ISO calls upon RMR energy), namely, the loss of the Reliability Payment. The owner therefore had an economic incentive not to bid or to bid very high into the day-ahead market whenever there was a high probability that (1) the ISO would call upon the unit to provide RMR service, and (2) revenues from the Reliability Payment would exceed net revenues from scheduling the unit in the day-ahead PX market.

The second problem, which applied to both Contracts A and B, was that an owner holding both RMR units and non-RMR capacity had an incentive to bid the RMR capacity either very high or not at all into the day-ahead or A/S markets, to increase revenues earned in those markets by the owner's non-RMR capacity. Under Contract B the owner had to rebate 90 percent of any market profits to the ISO, so there was little opportunity cost to keep the RMR unit out of the markets. By foregoing the 10 percent share of profit the RMR unit might earn and instead withholding the RMR energy from the day-ahead and A/S markets, the owner could raise market clearing prices and earn higher revenues from the non-RMR capacity.

The contract features described above provided a rational, profit-maximizing RMR owner with an incentive to withhold capacity or to bid high prices in the PX day-ahead energy market. The requirement to credit back 90 percent of market revenues earned by units under Contract B also created an incentive for these units to withhold or bid high in the A/S markets.

The MSC and the MSU tried to quantify the market distortions created by the contracts during the 1998 peak period. The MSC and the MSU estimated that potential inflation of market costs due to these distortions amounted to hundreds of millions of dollars. The MSU's *Report on Impacts of RMR Contracts on Market Performance* provides a more detailed analysis of the economic incentives created by these RMR contracts, and of the potential impacts of withholding or strategic bidding of RMR capacity on market costs.

For purposes of considering the benefits of modifying the RMR contracts, however, it was not necessary to determine their 1998 market impacts with precision. During the 1998 summer peak, the market was in a formative stage. Owners of generation resources were just beginning to test the market. The lessons learned would not be lost on 1999 participants. They could be expected, understandably, to exploit fully the profit potential inherent in the A and B contract structures.

Whether or not these bidding strategies were used in 1998, it could not be assumed that they would be ignored during future years.

6.5.2 Dispatch of RMR Units After the Day-ahead Market

Another way in which RMR contracts adversely affected California's energy market resulted from the current practice of dispatching RMR units after the clearing of the PX day-ahead energy market. This market design ignores the fact that RMR generation must run and ultimately will be used to meet demand. Thus it leads to excess supply being purchased in the day-ahead market, increasing the PX price. If demand in the day-ahead market did not include demand that would ultimately be met by RMR generation, the MCP would most likely be lower. The current design makes consumers pay twice for the local reliability provided by RMR units, once through direct fixed cost payments to RMR generators, and again through higher PX prices.

Under current ISO protocols, this excess supply spills over into the real-time imbalance market. When excess demand in real-time is less than the amount of RMR generation dispatched by the ISO after the close of the day-ahead market, non-RMR suppliers must be decremented to achieve balance. If excess demand in real-time exceeds RMR generation called for local reliability, the supply from RMR generation is, in effect, treated as must-take in the real-time market. In either case the spillover of RMR energy tends initially to lower real-time energy prices. At the same time, this practice may increase real-time demand by encouraging buyers to under-schedule their demand in anticipation of lower real-time prices. The end result may be higher or lower real-time prices, but with increased volatility.

6.5.3 Summary of the Partial RMR Settlement

In the spring of 1999, a partial settlement to revise the structure of RMR contracts was reached between owners of RMR units, the ISO, and transmission owners (TOs). The TOs pay the costs of RMR contracts as part of the overall costs of maintaining transmission system reliability. The following sections describe key features of this partial settlement, and how these RMR contract modifications may affect the energy and ancillary service markets.

6.5.3.1 RMR Contract Condition 1

Contracts A and B are replaced with a *market participation* contract, referred to as Condition 1 under the new contract. Under Condition 1 of the new contract:

1. Generation owners retain 100 percent of market revenues.

2. Compensation for RMR services is provided primarily as a fixed cost payment, in monthly installments with adjustments made based on actual unit availability. The payment includes pre-payment for startup costs, based on total number of startups for market and non-market transactions. The amount of the fixed cost payment for each unit under has not yet been determined, however, but has been reserved for litigation. On an interim basis, fixed cost payments will be based on levels filed with the partial settlement, with differences between the interim and final fixed cost payment levels resolved through a refund or surcharge to be made once final payment levels are determined.

3. RMR dispatch notices will be provided after close of the day-ahead energy and A/S markets. The agreement provides that anytime after October 1, 1999 the ISO may file with FERC for authorization to allow the ISO to issue dispatch notices for RMR energy prior to the opening of the day-ahead market, with a requirement that RMR owners electing the contract payment (see item 4) be treated as must-take in the PX day-ahead market.

4. Upon receiving a dispatch notice, RMR unit owners would have the option of selecting between a market and contract transaction.

   a. Under the contract transaction, owners would be reimbursed for variable operating costs of energy provided to meet RMR requirements.

   b. Under the market transaction, owners would notify the ISO of the market in which they intend to schedule the required RMR generation (day-ahead, hour-ahead, or real-time imbalance). If the owner chooses a market transaction in the hour-ahead or real-time market, the RMR energy would be treated as must-take in the selected market, using the mechanism of a zero-price energy bid for an amount of energy equal to or greater than the RMR requirement being met.

5. Owners will receive payment for any ancillary service capacity which RMR units win in the day-ahead market, but are pre-empted from providing A/S due to RMR energy requirements established after the close of the day-ahead market.

6.5.3.2 RMR Contract Condition 2

Under the partial settlement, the current Contract C is, in effect, replaced by Condition 2 of the new contract. Under Condition 2 of the new contract:

1. Generation owners do not retain any market revenues from operation of units; revenues from market transactions are credited to transmission owners.

2. Compensation for RMR services is provided primarily in the form a fixed cost payment, with adjustments made for actual unit availability. The fixed cost payment is equal to the full fixed costs (going forward fixed costs plus capital recovery costs).

3. When units are dispatched for RMR, energy necessary to meet RMR requirements will be bid into the subsequent energy markets as must-take.

4. Units only participate in market transactions during hours when the ISO has issued a dispatch notice for the unit.

5. During hours when the ISO issues a dispatch notice, the dispatched unit will be required to bid the full amount of energy and A/S capacity into subsequent markets at rates specified in RMR contracts. For energy, bid levels are based on the variable cost payments made to generation owners. For A/S, bid levels are based on formula rates similar to those previously used to set cost-based price caps. Units shall not otherwise engage in market transactions.

6.5.4 Market Impacts of the Partial RMR Settlement

6.5.4.1 RMR Contract Condition 1

- **Elimination of Reliability Payment Under Contract A**. The elimination of the Reliability Payment under current Contract A removes the disincentive to schedule the RMR units in the day-ahead market when (a) there is reasonable probability that the units will be called under RMR, and (b) market prices are lower than the total variable payment that would be received if the unit were called under RMR (i.e., variable operating costs plus Reliability Payment).

- **Fixed Payment for Startup Costs**. Payment of startup costs through a fixed, pre-agreed amount, which is added to the fixed option payment received by each unit, removes another potential disincentive for unit owners to start up units and participate in the market when there is reasonable probability of being called under RMR.

- **Retention of All Market Revenues by Unit Owners**. As previously noted, the requirement that units under current Contract B refund 90 percent of market revenues has the effect of reducing the opportunity cost of withholding RMR capacity from the market or bidding capacity from RMR units at higher prices in order to increase market prices earned by other units in a generator's portfolio. By allowing units to retain 100 percent of market revenues, Condition 1 of the new contract removes this disincentive.

- **Compensation through Fixed Option Payment.** By providing compensation to RMR units owners primarily through a fixed pre-agreed option payment, the new contract provides a more transparent and easily quantified price signal reflecting the premium being paid to meet local reliability requirements through RMR contracts. This price signal can be used by the ISO and other market participants to develop and assess competitive alternatives for meeting the local reliability requirements through new generation facilities, transmission system upgrades, or other options (e.g. demand reduction). In this manner, the structure of the new RMR contracts will more effectively promote longer-term competition among different alternatives for meeting local reliability requirements.

6.5.4.2 RMR Contract Condition 2

- **Market Participation Under Condition 2 of the New Contract**. Under the new contract, units electing to operate under Condition 2 of the contract would retain no market revenues, but would receive full fixed costs plus variable operating costs. Thus, Condition 2 in effect replaces Contract C of current RMR agreements. Bidding rules of Condition 2 require the full capacity of units to be bid into energy and A/S markets during hours when they are dispatched for RMR, and would therefore result in a significantly higher level of market participation than exists under the current Contract C. However, overall market participation of units under Condition 2 would be significantly decreased relative to historical levels, as well as levels of market participation under Condition 1. For instance, analysis of 1998 operating data for RMR units indicates that under bidding rules for units under Condition 2, the amount of energy and A/S provided by RMR units switching to Condition 2 could decrease by as much as 35 percent and 63 percent, respectively, compared to the amount of energy and A/S capacity provided by these units during 1998.[3] Decreased market participation by units under Condition 2 would result in higher energy and A/S prices.

- **Fixed Cost Payment**. First, it is important to note that the level of fixed cost payments for units under Condition 2 primarily involve issues of equity rather than economic efficiency. An important exception to this is that option payments must be such that units do not have an incentive to select Condition 2 rather than Condition 1. This issue and the equity of option payments are discussed below.

6.5.5 Key Unresolved Issues

Under the partial settlement agreement, two key unresolved issues with significant potential impacts on the design and efficiency of California's energy markets are reserved for further negotiation and potential litigation.

6.5.5.1 Level of Fixed Option Payment

The level of fixed option payments for units under Condition 1 are interim, and are subject to adjustment through a refund or surcharge, depending on the outcome of further negotiation and potential litigation. To ensure that units needed for reliability are not "mothballed," fixed cost payments under RMR contracts need only include going forward fixed costs, rather than total fixed cost (including capital recovery payments covering *sunk* costs). However, since RMR unit owners are allowed to select between Condition 1 and Condition 2 of the new contract, each owner will select whichever contract option provides the greatest perceived benefit. Thus, fixed option payments under Condition 1 must be carefully structured in order to avoid having a significant amount of capacity select Condition 2 of the new contract.

6.5.5.2 Treatment of RMR as Must-Take in Day Ahead Market

The interim settlement eliminates the major features of Contract A and B that reduce the economic incentive for RMR units to participate in the energy and Ancillary Service markets. However, the variable cost payment received when units are called to provide RMR energy can still provide an incentive for units not to participate in the day-ahead market during hours when market prices are lower than variable operating costs, but it is nonetheless economic for units to continue operating at minimum levels due to start-up costs and other operating constraints. Thus, the only way to eliminate the effect of these variable cost payments entirely is to pre-dispatch RMR generation and treat this energy as must-take in the day-ahead market.

As noted above, unless demand that will ultimately be met by RMR generation is "netted out" of demand in the day-ahead market (i.e. by requiring that RMR generation be scheduled through a bilateral contract or treated as must-take in the PX day-ahead market), excess supply will be purchased in the day-ahead market. The agreement to defer the issue of treating RMR as must-

[3] Calculated for the period from April to December 1998, based on the sum of scheduled energy and A/S provided by an RMR unit during hours when that unit had a Minimum Reliability Requirement specified by the ISO for that hour, as a percentage of the total amount of scheduled energy and A/S provided by RMR units over this same time period.

take in the day-ahead market was made in the interest of reaching a partial settlement agreement under which modified RMR contracts could be implemented by the summer of 1999. By allowing the ISO to file for FERC approval of a tariff provision for treatment of RMR as must-take in the day-ahead market on or after October 1, 1999, the partial settlement allows for this issue to receive thorough consideration by FERC without delaying implementation of the other modifications prior to the critical peak load season of 1999.