CALIFORNIA ISO

Report on California Energy Market Issues and Performance: May-June, 2000

Special Report

Prepared by the Department of Market Analysis
California Independent System Operator
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Summary of Findings and Recommendations

In late May and June of this year, prices in the California energy markets were significantly higher than expected. Prices in the Power Exchange's Day Ahead market and the ISO's real time energy market reached the ISO's $750 price cap during many hours. The ISO's Department of Market Analysis (DMA) examined market activity during these two months to determine the underlying causes for the high wholesale prices. DMA found that the high prices were the result of the combination of several factors, including (1) unusually high demand for electricity region-wide due to unseasonably high temperatures and recent economic growth, (2) a doubling of gas prices over the last year, and (3) the fact that no significant new supply has been added in California in recent years. The combination of very tight supply and demand conditions — in conjunction with very limited ability of consumers to reduce consumption in response to rising prices — created absolute shortages of supply, as well as the opportunity for the exercise market power during many hours. The exercise of this market power further inflated wholesale prices well above levels that would have resulted under competitive market conditions.

The performance of the ISO markets over the past two years has shown that workable competition has existed for most hours of the year (i.e. for all but about 1 to 2% of total annual hours). During those hours, supply has been sufficient to cause competition among suppliers. Our findings show that when workable competition exists, prices tend to be close to the short-run variable cost of the highest-cost generating unit required to meet demand. However, during high load hours, the combination of tight supply conditions and the limited ability of consumers to reduce consumption in response to prices creates the situation in which any firm that owns a significant share of the generation serving the state can exercise market power to inflate wholesale prices.

While California has experienced robust economic growth during the past decade, there has been very little investment in new generation and transmission within California over the last 15 years. As a result, the ample reserve capacity California has enjoyed in the past has shrunk to a dangerously low level. During peak load days in May and June, reserve margins were further reduced by unusually high levels of generation unit outages and a decrease in available supplies of out-of-state energy. This combination caused unusually high prices in both the PX and ISO markets and resulted in a high overall cost of wholesale power. If supply had increased to keep pace with even a modest share of the growth in demand over the past decade, there would have been sufficient reserve margins and a sufficient number of new supply entrants to allow competitive markets to moderate electricity prices this summer.

In markets where consumers have the ability to respond to price increases by reducing consumption, extraordinarily high prices during periods of true shortage of supply may be seen as legitimate "scarcity rents" because they reflect the willingness of consumers to pay for electricity. Moreover, where scarcity prices are set by consumer willingness-to-pay and there are no barriers to the entry of new suppliers, occasional high prices under scarcity conditions are important signals to new generators to enter the market. However, where consumer responsiveness and new entry are severely limited, as in today's electricity markets, the ability of suppliers to exercise market power under tight supply conditions cannot be limited by competitive market forces. In this situation effective mitigation of market power must be accomplished through rules, procedures and incentives designed into the structure of the markets themselves. The fundamental solution to mitigate this market power is to create ways for consumers to respond to increasing prices and accelerate entry to the market by new suppliers.

Based on our examination of the market, we believe that actions have to be taken to remedy the high costs experienced in May and June, and additional actions will be taken to further improve the performance of the market. All of the recommendations noted below are part of a comprehensive ISO Action Plan that outlines a number of short- and long-term initiatives which require ISO, UDC and state agency action. The ISO Board has already taken the immediate step to contain wholesale energy costs by lowering price caps to $250. This is only a first step. Additional actions are needed, and could include:

- **Accelerating the permitting and siting of generation and transmission projects**. One of the primary reasons for high prices has been the underlying tight supply conditions in the California market, which have been developing for more than a decade. Action should be taken to increase the amount of in-area generation through expedited siting and permitting of generation and transmission facilities that will be critical to ensuring that the supply of resources keeps up with needs created by accelerated load growth. We believe that expedited approval can and must be accomplished without compromising the need for adequate environmental impact review. In fact, we would expect enhanced environmental quality to result with the addition of cleaner, more efficient generation, and the re-powering of aging and inefficient resources with cleaner technologies.
- **Placing a priority on developing load responsive programs and removing barriers to load's ability to hedge**. These structural changes are critical to promoting competitive market outcomes by allowing load to protect itself from high prices. In the near-term, while the utility distribution companies (UDCs) are the retail electricity providers for the vast majority of California's load (and the exclusive default service providers), this involves expanding the ability of the UDCs to develop extensive load response programs and to enter forward hedging contracts in the wholesale markets. Forward financial contracts when combined with a retail rate freeze are an important measure for mitigating market power in all restructured spot markets.
- **Ensuring that the UDCs have adequate incentives to conduct their wholesale market activities in the most efficient manner possible to keep retail rates low.** At present the retail rate freeze and the rules for collecting CTC provide such incentives. However, as the recent experience of SDG&E's ratepayers indicates, once these mechanisms end there may be inadequate incentives for the UDCs to strive to minimize the costs of electricity for end users. Direct incentives such as the retail rate freeze on UDCs are critical mechanisms to mitigate market power in the wholesale electricity markets. This is because UDCs have the financial interest (dollar for dollar) to maintain low wholesale costs. This incentive causes them to work diligently using their knowledge of markets and remaining resources to keep wholesale prices low.
- **Promoting robust retail competition by removing key regulatory barriers.** In the longer–term, promoting competition among retailers will provide the incentive to keep electricity supply costs low. Among the current regulatory barriers are the lack of definition and structure for default service rates and the structure needed to provide the right incentives and opportunities for competitive provision and innovation in revenue cycle services (e.g. metering, meter reading, billing services, etc.).

Since the above recommendations will take time to implement, the ISO has imposed an immediate reduction of the price caps in its markets to $250/MWh as a short-term measure to contain wholesale prices. In addition, we are examining other changes to market procedures that might be implemented in the short-term to increase the incentives for generation owners to schedule their energy on a forward basis rather than transacting substantial percentages of total system needs in the real-time market.

In summary, the major cause of high wholesale prices this summer has been the absence of new investment in generation and transmission to meet the growth in demand over the past decade. The major cause of these high prices being passed on to retail customers in the SDG&E service area was the absence of means for final customers to respond to high wholesale prices, and the failure to provide any other market participant besides final customers with the financial incentive to maintain low wholesale prices. The Department of Market Analysis has identified the above measures, which include offering real choices to retail customers to protect themselves against high prices, as crucial to helping promote a more competitive wholesale electricity market in California.

EXECUTIVE SUMMARY

This report reviews the performance of California's energy and ancillary service markets from late May to mid July. It focuses on the key causes and market structure issues underlying the series of price spikes and high costs over this period. The body of the report examines in more detail the specific factors that contributed to price spikes in May and June. The major factors can be summarized in three areas:

- High Demand and Tight Supply in California and Regional Markets
- Market Design and Operational Features that Contributed to High Cost
- Market Power and Scarcity Rent

I. High Demand and Tight Supply in California and Regional Markets

- **High Peak Demand Growth**. A major factor underlying the price spikes in May and June was high levels of demand. This was due to robust economic growth throughout the West over the last few years, coupled with unseasonably high temperatures, which reached 1-in-10 year highs for the months of May and June in many parts of the state. Average daily peak loads grew by 13% in May and 15% in June compared to these same months of 1999.
- **Units on Scheduled Maintenance and Forced Outages**. Because May and June are typically marked by relatively moderate loads, high hydro run-off, and some of the lowest energy prices of the year, this is traditionally a period when maintenance is done to prepare generation units for the peak summer months. In addition, the May and June price spikes coincided with an unusually high rate of forced outages within the ISO system, as well as in other control areas. During the May 22 price spike, about 22% of the state's nearly 17,000 MW of thermal generation recently divested by the state's IOUs to Non-utility Generation Owners (NGOs) was unavailable due to scheduled maintenance and forced outages. During the June price spikes, an average of about 10% of this generation capacity was unavailable due to scheduled maintenance and forced outages. Although these current outage rates may seem high compared to long-term historical outage rates, we expect that maintenance and forced outage rates may increase from historical levels due to the increasing age of the existing stock of generation plants.[1] These unit outages – combined with a variety of transmission system outages – also played a key role in local area shortages and reliability problems. These issues are the subject of reports and information provided by other departments of the ISO.
- **Higher Gas Prices**. There has been a significant increase in natural gas prices with an almost doubling from $2.50/MMBTU in June of 1999 to $5.00/MMBTU in June of 2000. The recent increase in gas prices is the most easily quantified factor underlying the high costs of electricity in June. About 20% of the increase in overall electricity costs in June 2000 compared to Summer 1999 can be attributed to the doubling of natural gas prices over the last 12 months.[2] As loads moderated during the first two weeks of July 2000, electricity prices returned to 1999 levels when adjusted for the increase in natural gas prices over the last 12 months.

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[1] Over 60% of California's gas and oil-fired generation capacity is over thirty years old. As power plants age, they require more maintenance and are more prone to outages. In addition, current demand and supply conditions are causing many older plants to be operated and "cycled" on and off with increasing frequency, which tends to increase the frequency of maintenance and forced outages.

[2] See Table 2 of report for details of this analysis.

- **Lack of New Investment in Generation and Transmission.** Despite robust economic growth, there has been little new investment in generation and transmission in California during the past 15 years.
- **Tight regional supply and reduced imports.** Tight regional demand/supply conditions affect California's deregulated energy market in several ways. First, because California requires significant imports of electricity to meet demand during peak demand periods, tight regional supply conditions reduce the supply (and increase the cost) of imports available to meet demand. In addition, tight regional supply conditions – combined with the development of regional market hubs in which merchant generators may sell electricity – also increase the opportunity cost (and decreases the supply) of power within California available to meet demand. Finally, tight demand and supply conditions on a regional level also create the potential for the exercise of market power on a regional level by entities controlling available excess supply (i.e. supply beyond what an entity may need to meet its own load or pre-existing contract obligations). Diagnosing the amount of market power that may exist and be exercised on a regional level is extremely difficult, and will be the subject of further investigation by the ISO in conjunction with other entities.

II. Market Design and Operational Features that Contributed to High Cost

In addition to the tight supply and demand conditions, several fundamental features of California's market structure and design play a key role in explaining recent market performance and price spikes. Some of these are likely to continue facing the ISO in the coming months.

- **Lack of Demand-side Response to Prices.** Critical to the working of all deregulated markets is the capability of loads to respond to prices and hedge against high prices. There are many regulatory barriers to bringing about price-responsive demand and forward market hedging within the current California market structure.
- **Under-scheduling of Loads and Generation.** Recent aggregated bid information released by the PX shows that supply being offered in the PX market is lower in quantity and higher in price than the supply offered under comparable load conditions last year.[3] Decreased supply in the PX is attributed to two key factors. First, a significant amount of thermal capacity divested to merchant generators is being scheduled through bilateral contracts or through regional block forward and spot markets. Of capacity scheduled through these bilateral or forward market contracts, a significantly greater amount appears to have been purchased for out-of-state markets. The result has been an increase in gross exports and a decrease in overall net imports into the California market. In addition, high real-time and replacement reserve purchase prices and quantities have created a significant opportunity cost that may have led suppliers to withhold or bid higher prices in the PX Day Ahead market.

  Price spikes in the ISO's real-time market during May and June occurred primarily during hours when the ISO needed to increment significant amounts of generation in real time in order to meet demand due to under-scheduling of loads and generation in the Day Ahead and Hour Ahead markets. Most under-scheduling can be attributed to strategic bidding of demand and supply resources in the Day Ahead and Hour Ahead markets. Until recently, large buyers appear to have successfully limited their exposure to overall wholesale price spikes by their ability to shift demand into the real-time market. However, the ability of large buyers to "defend" against potential exercise of market power and lower costs during periods where there is a true shortage of supply has been limited in recent months due to

[3] See presentation on *Price Behavior in Cal-PX Markets: May-June 2000*, prepared by PX compliance Unit for the Energy Oversight Board, June 29, 2000, available in archives on PX website (calpx.com)

suppliers offering less supply at higher prices in the Day Ahead market and the ISO's policy to charge replacement reserve to under-scheduled load and over-scheduled generation.

- **Replacement Reserve Procurement Policy.** One of the key adjustments the ISO made following the May 22 events was to implement an operational practice of *defending* against significant under-scheduling of loads (and avoiding potential *out-of-market* purchases). The ISO would purchase large volumes of replacement reserve capacity to narrow the gap between scheduled and forecasted loads. In some hours, as much as 25% of system needs were met in the real-time market. This significant level of under-scheduling is largely attributable to the different market incentives faced by buyers and sellers. Large buyers try to "defend" against higher prices in the PX Day Ahead Market by shifting some of their demand to the real-time market and suppliers have offered less supply at higher prices in the Day Ahead market because of opportunities to earn higher replacement reserve payments and real time energy prices. An important objective from a reliability perspective is to limit the amount of transactions in real time. Creating stronger incentives for load and suppliers to bid and schedule in the forward markets will help reliability and promote more competitive markets.

- **Reliance on Supplemental Energy from Other Control Areas.** A key issue encountered during the May and June price spikes involves the difficulty of relying on supplemental energy bids (representing "unreserved" capacity) from other control areas to meet demand in real time during periods of tight regional supply/demand conditions. During extremely tight supply conditions, supplemental energy bids from neighboring control areas have decreased significantly. This occurs precisely when the ISO projects a shortfall of operating reserves and faces the need to initiate *out-of-market* purchases from suppliers in neighboring control areas in order to ensure sufficient supplies for projected peak demand in the afternoon hours.

  When purchasing energy *out-of-market*, the ISO has typically purchased multi-hour blocks of energy at prices at or near the $750 price cap. *Out-of-market* purchases made during May and June included some multi-hour blocks of energy purchased at $750/MW, which spanned hours during which the *ex post* real-time imbalance price (the price paid to suppliers subsequently dispatched through the ISO's hourly real-time imbalance market) was below $750. From the ISO's perspective, this experience highlights the difficulty of relying on supplemental energy supplies to ensure system reliability: Suppliers *negotiating out-of-market* transactions for blocks of energy at prices that may be higher than the ex-post price seriously undermine the operations of the ISO energy and ancillary services markets. If in-state generators know that a better deal can be had from out-of-market purchases than from participating in the ISO's market, then we would expect them to export their power to out-of-state control areas and reduce their participation in the ISO's markets, thereby exacerbating the need for *out-of-market* purchases under tight supply/demand conditions.

  From the perspective of the out-of-control-area suppliers, sales of blocks of energy during very tight supply and demand conditions provide a number of advantages. These include the ability to compare revenues from sales to the ISO against potential sales in other regional spot markets and bilateral transactions that are not conducted based on real-time hourly markets with *ex post* market prices. However, from the perspective of suppliers within the ISO control area, any out-of-market purchases of energy at prices higher than the *ex post* price unfairly discriminate against suppliers participating in the ISO's hourly real-time market.

  The ISO's reliance on out-of-market purchases also creates operational concerns, due to the "manual", case-by-case nature in which out-of-market purchases may need to be made. Relying on out-of-market mechanisms to meet a large volume of demand in real time involves significant inefficiencies (as well as potential reliability concerns) in the event that either “too much” or “too little” energy is purchased out-of-market to meet real time demand.

III. Market Power and Scarcity Rent

In restructuring the California power market, divestiture of generation resources was an important means of mitigating market power. None of the current non-utility generation owners have more than a 9% of share of total generation capacity in California, and previous analysis[4] shows that the California wholesale energy market is competitive except for peak demand hours. Under the tight demand and supply conditions experienced in May and June of 2000, however, the incidence of high prices clearly highlighted that the remaining market power can have an extremely costly impact.

Our analysis of the events of May and June and the behavior of market participants in causing price spikes distinguishes between the exploitation of *market power* and *scarcity rents* which are derived from true willingness of consumers to buy under conditions of scarcity or shortage of supply. The classical economic definition of a workably competitive market is one in which a large number of firms compete to produce the same product and no firm is able to raise prices significantly above system marginal costs for a sustained time period. A workably competitive market produces market clearing prices which are reasonably close to system marginal cost, i.e. the highest cost unit necessary to serve the load. Market power exists if firms have the ability to raise prices significantly above system marginal cost for a sustained period of time unimpeded by competition from other suppliers, other substitute products, or demand response.

Not all incidences of price exceeding system marginal cost are evidence of market power, because scarcity rents are legitimate during hours of shortage. Scarcity rents are appropriate when the level of electricity demand is such that there is little, if any, unused capacity available throughout the system and consumers have the ability to reduce their purchases as the price rises. In these instances, prices in the market should be set by the willingness of consumers to forego purchases of electricity, rather than by the bids of generators. These market conditions indicate genuine scarcity of generating capacity, because all available capacity is used and no additional capacity exists to serve any incremental increase in demand.

Due to the extremely limited degree of demand elasticity that currently exists in California’s newly deregulated energy market, the ISO’s real-time price cap has had to serve as a proxy for consumers’ willingness-to-pay during periods of true scarcity, as well as the limit on generator market power during periods of high demand. However, while price caps can serve as a proxy for consumers’ willingness-to-pay during periods of true scarcity and limit market power during periods of high demand, price caps do not allow price signals to actually be sent to consumers, many of which would reduce demand if exposed to extremely high prices. Thus, price caps represent a very imperfect proxy for actual demand elasticity.

Shortage can be defined for two geographic areas: a California ISO control area shortage and a greater Western regional shortage. A California ISO control area shortage is when net demand for capacity[5] (total demand for capacity minus actual imported energy and reserve) is greater than the available capacity from

[4] Frank Wolak, Borenstein and Bushnell, “Diagnosing Market Power in California’s Restructured Electricity Market,”, April , 2000, available from http://www.stanford.edu/~wolak.

[5] Demand for capacity is the demand for energy plus losses and requirements for operating reserves and upward regulation service (measured in MW for any particular hour).

generation resources inside the ISO control area. This type of shortage is influenced by the amount of available imports. The regional shortage definition extends the scope to the surrounding control areas to cover the entire WSCC region, and compares the entire regional demand for capacity with available capacity in the region.

Our preliminary analysis shows there were shortages in the California ISO control area for a number of hours, when available capacity was not sufficient to meet the net demand for capacity. There were other high price hours when we cannot identify any apparent shortage and the high prices can clearly be attributed to market power. The presence of market power can be verified by bid prices significantly over the variable costs of many suppliers in the ISO's markets. The highest variable cost of in-state generators is below $100/MWh, while many suppliers routinely bid a significant part of their capacity at $750 (the price cap level). With supply limited and high demand, these bids are guaranteed to be selected to meet the demand during high load periods.

The observed market power was the combined effect of the bidding activity of in-state and out-of-state generation resources. The available data and tools do not allow detailed analysis of the market power of out-of-state generation owners. The ISO, however, is not aware of any acute regional shortages in most of the high price hours. The high prices bid by out-of-state suppliers as well as the high prices quoted to ISO's out-of-market calls are indications of the market power of out-of-state suppliers.

The divestiture of generation resources by IOUs has resulted in a market share of approximately 9% for a few of the large non-utility generation companies. These companies are net sellers who can profit from price spikes. While for most hours the ISO markets are sufficiently competitive, at high load conditions, a capacity share of 9% or less can give market suppliers a pivotal position. This implies that, at high load conditions, even suppliers with less than a 9% market share can have significant market power. When net demand for capacity in the ISO control area is more than 91% of available capacity, all suppliers can easily bid high prices, and know their bids will be accepted and set the market clearing price. Thus, prices have hit the price cap during many hours even when there is not a shortage on the system.

Fundamental Corrective Measures

The following fundamental could be implemented to facilitate the development of workably competitive wholesale energy markets:

- **Expedite Generation and Transmission Investment.** Although it is clearly a long-term market power mitigation measure, the California Energy Commission and other state agencies should expedite the siting and approval process for all new plants under consideration. The fact that siting power plants in California takes considerable longer than other surrounding states hinders the ability of new entry to mitigate market power. These state agencies should also allow the ISO to take a pro-active role in the determination of the need for new transmission investment. Given that transmission constraints enhance the ability of generators to exercise their market power, transmission upgrades have the potential to significantly increase the efficiency of the ISO's energy and ancillary services markets. Consistent with siting and environmental review, any transmission upgrade that reduces total energy and ancillary services costs on an annual basis by more than the annual cost of the transmission upgrade should be undertaken as soon as possible.

- **Clarification of Retail Sector Structure.** An important contributing factor to the price spikes in the ISO's energy and ancillary services market is the lack of clarity regarding the structure of the retail sector. Under the current market rules, in any UDC territory not subject to a retail rate freeze, there are no market participants, besides individual consumers, with an incentive to lower wholesale prices. Because hourly wholesale prices must be passed through in retail rates, higher wholesale prices simply increase the cost of doing business to all retail suppliers. Given that all the parameters necessary for robust retail competition have not yet been determined by the California Public Utilities Commission (CPUC), there is also little reason to believe that retail competition will provide the strong incentives to lower wholesale prices.
- **Remove Barriers to Demand-Response Programs and Hedging.** Crucial to the success of any initiatives in the retail sector is the removal of all regulatory barriers to forward contracting by all load-serving entities, including the UDCs. Had the UDCs had the ability to fully contract their peak net demand position in the forward energy markets, it is unlikely that nearly as many price spikes would have occurred during May and June, and those that did would have been significantly less costly to final load. By restricting forward purchases by the UDCs to the PX block forward market, the CPUC is restricting the ability of these load-serving entities to mitigate market power in a least-cost manner. A second crucial feature to the success of either of the above two options to mitigating market power is to remove all regulatory barriers to price-responsive final demand. Either of the above two solutions must allow all UDCs complete freedom in configuring price-responsive demand programs. Subject to the retail rate freeze in the first option or robust retail competition under the second option, all load serving entities should be able to offer pricing contracts which support a price-responsive hourly demand.
- **Market Power Mitigation Options Should Include Maintaining Short-term Purchase Price Caps and Instituting Incentives for Forward Scheduling.** A short-term option for the summer of 2000 was to implement lower purchase price caps on the ISO's energy and ancillary services markets. Because of inadequate forward market purchases by the UDCs for the summer of 2000, price caps were one of the few short-term options for market power mitigation available to the ISO. However, there are uncertain reliability costs associated with implementing lower caps, with the ISO having to make out-of-market purchases at whatever price is necessary to maintain system reliability. This also creates a tremendous incentive for in-state resources to export outside of the ISO control area during high demand periods in order to sell this energy back into California through out-of-market transactions. Reliability concerns also dictate that the ISO have options to encourage all available capacity to be either submitted in a day-ahead energy schedule or bid into the ISO's day-ahead ancillary services market. Some potential options for reducing underscheduling include: charging bids or schedules not submitted in the Day Ahead (bilateral, PX, or ancillary service) markets, additional fees for transactions in real-time markets, establishing an availability standard, and penalizing physical withholding and/or specifying a requirement for a certain portion of loads to be forward scheduled. However, each of these options should be carefully examined to assess the potential positive and negative market impacts.

The following report provides a more detailed discussion of these events and issues summarized above. The report is organized as follows:

- Section II provides an overview and chronology of market performance and events from late May to mid-July 2000.
- Section III provides an estimate of the total market costs during this period, examines how these costs impact different market participants over the short-term, and summarizes these recent costs in a longer-term perspective of market energy costs before and since deregulation.
- Section IV examines the issue of underscheduling of load and generation, and potential options that have been proposed or discussed for reducing the operational problems stemming from underscheduling.
- Section V reviews the role that purchasing large quantities of replacement reserve may play in ensuring reliability, as well as total energy costs.
- Section VI examines the relationship between the California's energy markets and other regional markets, and how this relationship may impact policy and market design decisions.
- Section VII examines the issue of scarcity vs. market power in the context of the recent price spikes, and other related issues discussed in this report.

II. Overview of Market Events and Performance

This section provides an overview of demand and supply conditions during the May and June price spikes. Subsequent sections provide a more detailed discussion of underlying causes and impacts of the price spikes. The price spikes occurring during May and June were triggered in large part by unseasonably hot weather, which — coupled with the significant economic growth that has occurred over the last two years – created record high electric loads for these months. Unlike most heat waves experienced during the ISO's first two years of operation, the May and June heat waves coincided with high demand (and unusual amount of forced and scheduled outages) on a regional level. As a result of these factors, the number of hours when peak loads hit critical levels in terms of both market power and potential scarcity of regional supply grew dramatically.

Chronological Summary of Market Performance

May Price Spikes

- Price spikes in May began in the real time market on May 21, when actual peak loads exceeded forecasted by nearly 3,000 MW, or about 9% (see Figure 1). On May 21, prices approached the ISO's real time price cap several hours, hitting \$632 and \$732 during hours 15-16, while prices in the PX Day Ahead market (clearing on May 20) remained below \$52 during all hours (see Figure 3).
- Price spikes at the \$750 continued in the real time market on May 22, when loads peaked at 39,532 MW, and PX prices rose to over \$200 during the early evening hours. On May 22, the ISO purchased over 9,100 MWh of energy out-of-market for hours ending 12 – 21 (or an average of over 1,000 MW per hour over this 9 hour period) from suppliers outside the ISO's control area in order to ensure system reliability in the face of forecasted loads of over 40,000 MW. The price for most energy purchased out-of-market on May 22 was \$750, with average price of \$723/MWh, compared to a weighted average ex post price of about \$523. Additional information on out-of-market purchases in May and June is provided in Section II of this report.
- Prices in the PX rose to over \$400 for operating day May 23, while prices in the real time market dropped. This trend may be attributable in large part to the fact that actual loads on May 23 fell well below the level of loads being forecasted at the time of the Day Ahead market (run May 22 for operating day May 23), as shown in Figure 2.
- Prices in the PX remained over \$200 during the super peak hours of May 24, while prices in the real time market dropped to under \$50 during these hours. This trend may again be attributable in large part to the fact that actual loads on May 24 fell well below the level of loads being forecasted at the time of the PX Day Ahead market the previous day (see Figure 2).
- During the May 21-24 period, PX prices spiked over \$100/MW at loads of over 30,000 MW, and spiked over \$200/MW as loads exceeded 35,000 MW. As discussed later in this report, price spikes during June occurred primarily during hours when loads exceeded 35,000 MW, and neared the \$750 level as loads exceeded 40,000 MW. This difference reflects the difference in the amount of capacity unavailable during these two periods. During the May 22-25 period, about 6,600 MW in ISO control area was unavailable due to outages, while the amount of capacity out during the June price spikes generally ranged from 2,000 to about 3,000 MW.

Figure 1. May Load Conditions (1999 vs. 2000)

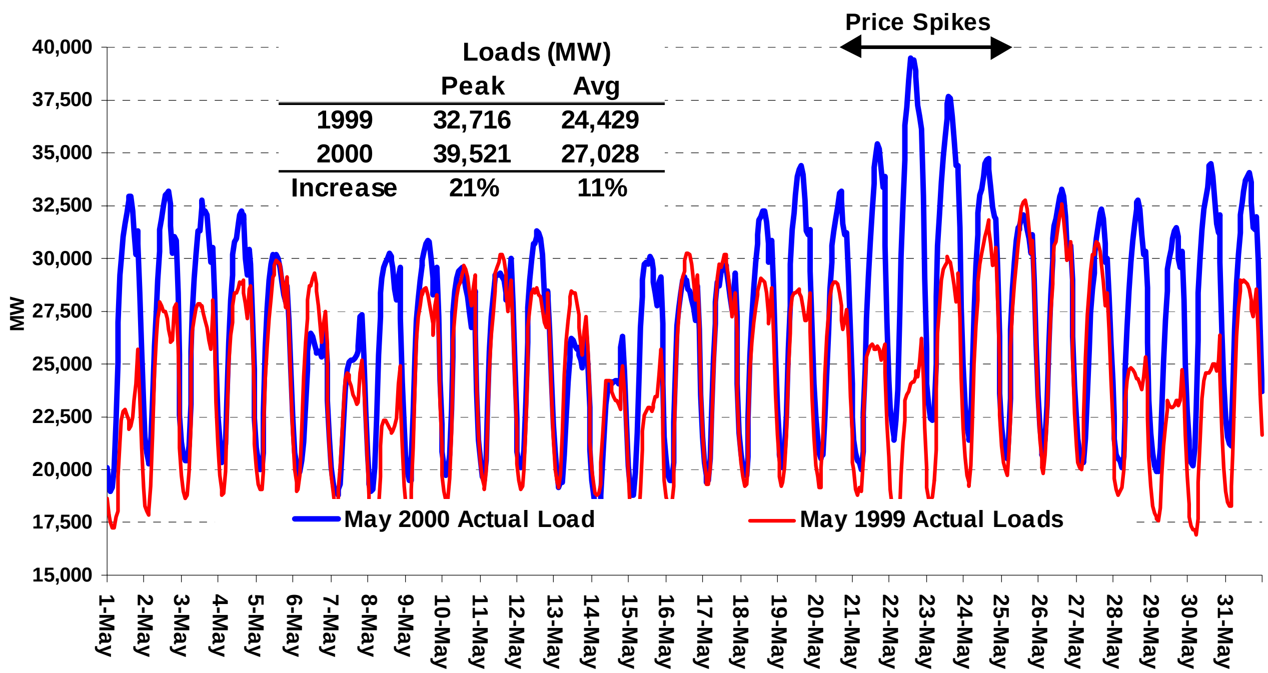


Figure 2. Loads and Schedules During May Price Spikes

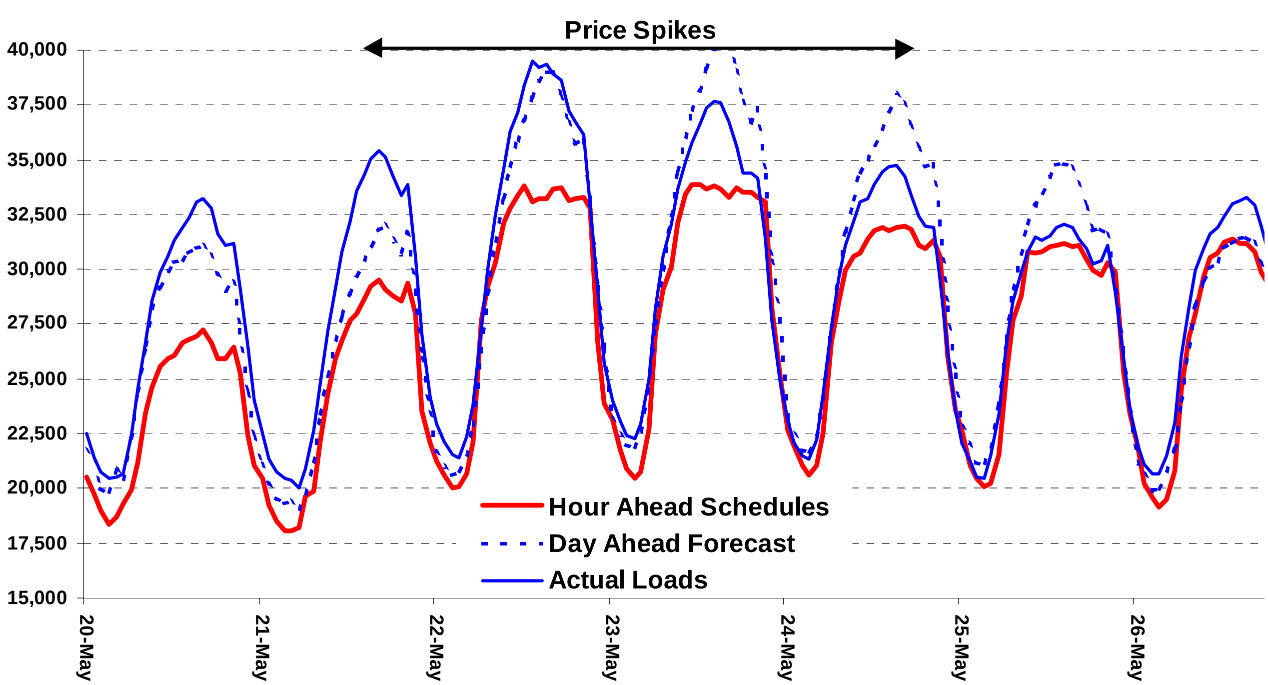
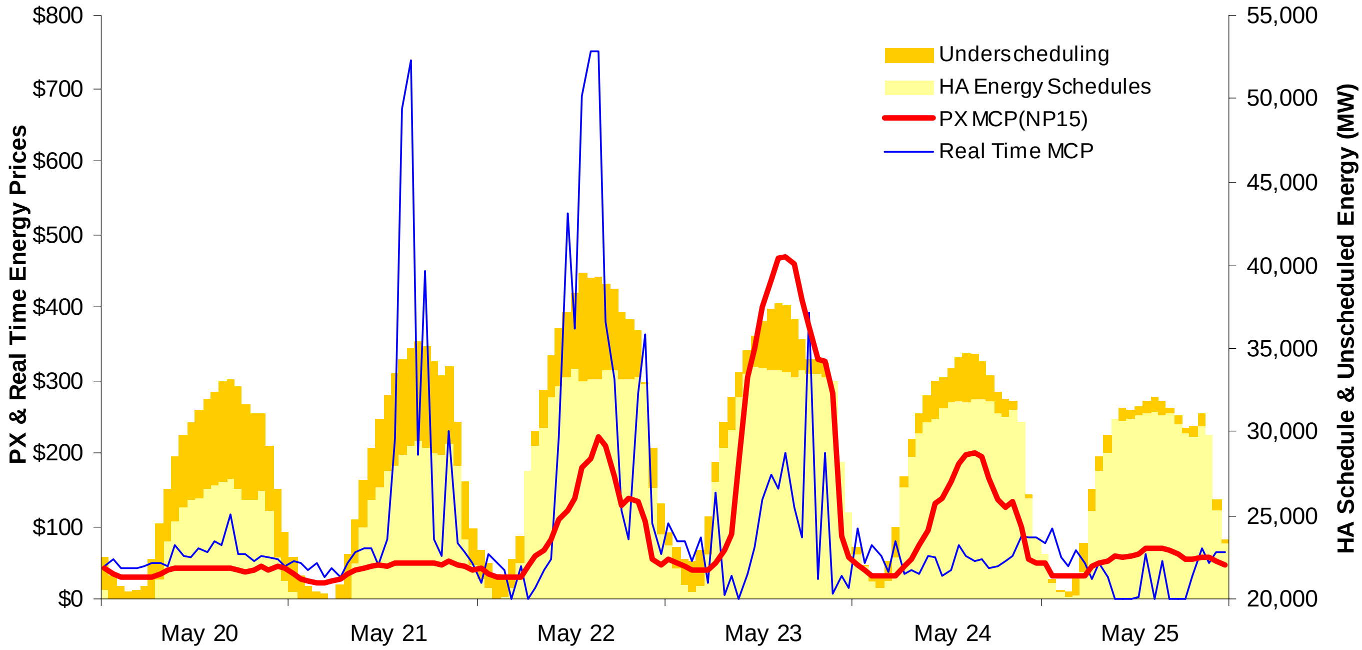


Figure 3. PX Day Ahead and Real Time Imbalance Prices (May 20-25)



June Price Spikes

- In June, average daily peak loads grew by 15% in May, with peak loads growing by 6% compared to May 1999 (see Figure 1).
- Loads exceeded 40,000 MW during 51 hours in June, compared to a total of only 56 hours of loads over 40,000 experienced during the entire three month period of June-August, 1999. Most of the hours when loads exceeded 40,000 fell during two major heat waves: June 13 –16, and June 26-30.
- Severe price spikes in the PX Day Ahead energy and ISO's ancillary service and real time markets occurred during two major heat waves: June 14 –16, and June 26-30. As discussed in the following section of this report, over 70% of up to $3.6 billion in market costs incurred during the month of June were incurred during the peak hours of these eight days.
- During the June 14-16 period, prices in the PX Day Ahead market averaged $387 during the peak hours (7–22), and exceeded the $600 level for 5 hours during this 3-day period.
- Despite peak daily loads over 40,000 MW on June 21-22, PX Day Ahead prices did not rise above $271. Real time prices exceeded $700 during 4 hours during this period, hitting the $750 cap during two hours on June 21.
- During the June 26-30 period, PX Day Ahead prices averaged $381 during peak hours (7 to 22), and reached or exceeded the $749 level during seven-hour block on both June 28 and 29. On June 28, constrained prices in NP15 reached an all-time high of $1099 for five hours.

Figure 4. June Load Conditions (1999 vs. 2000)

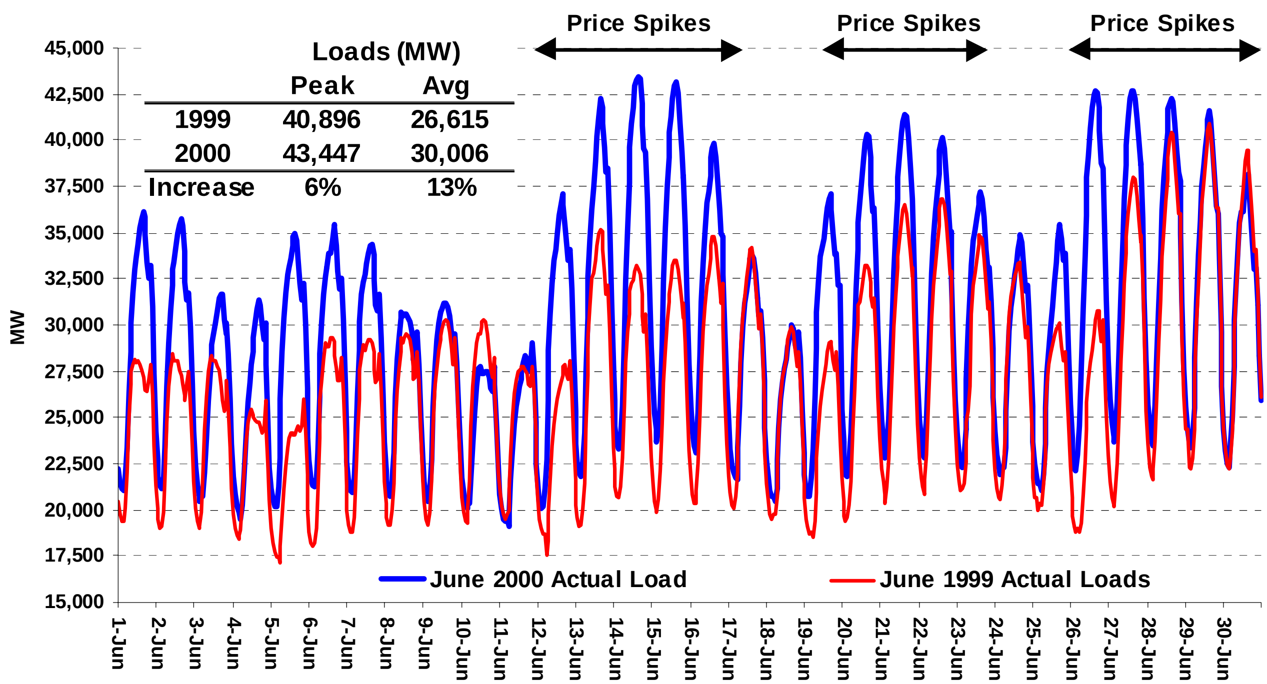


Figure 5. Loads and Schedules During June Price Spikes

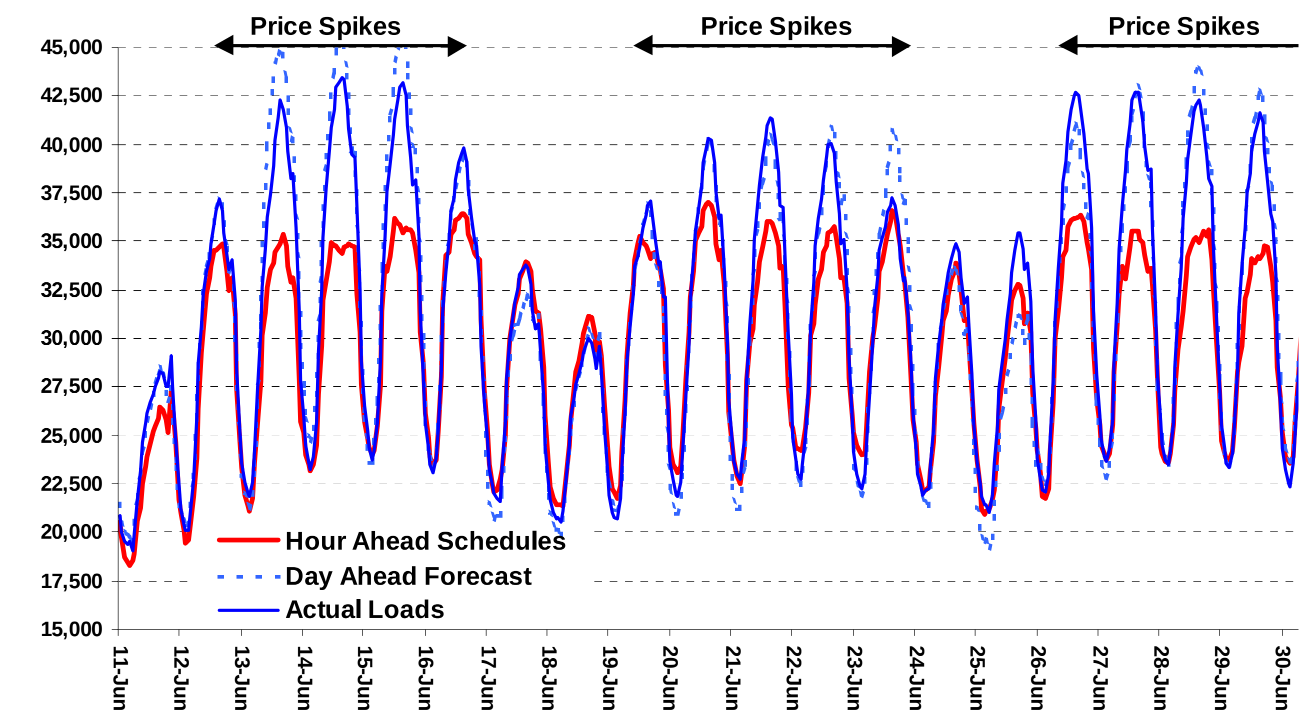
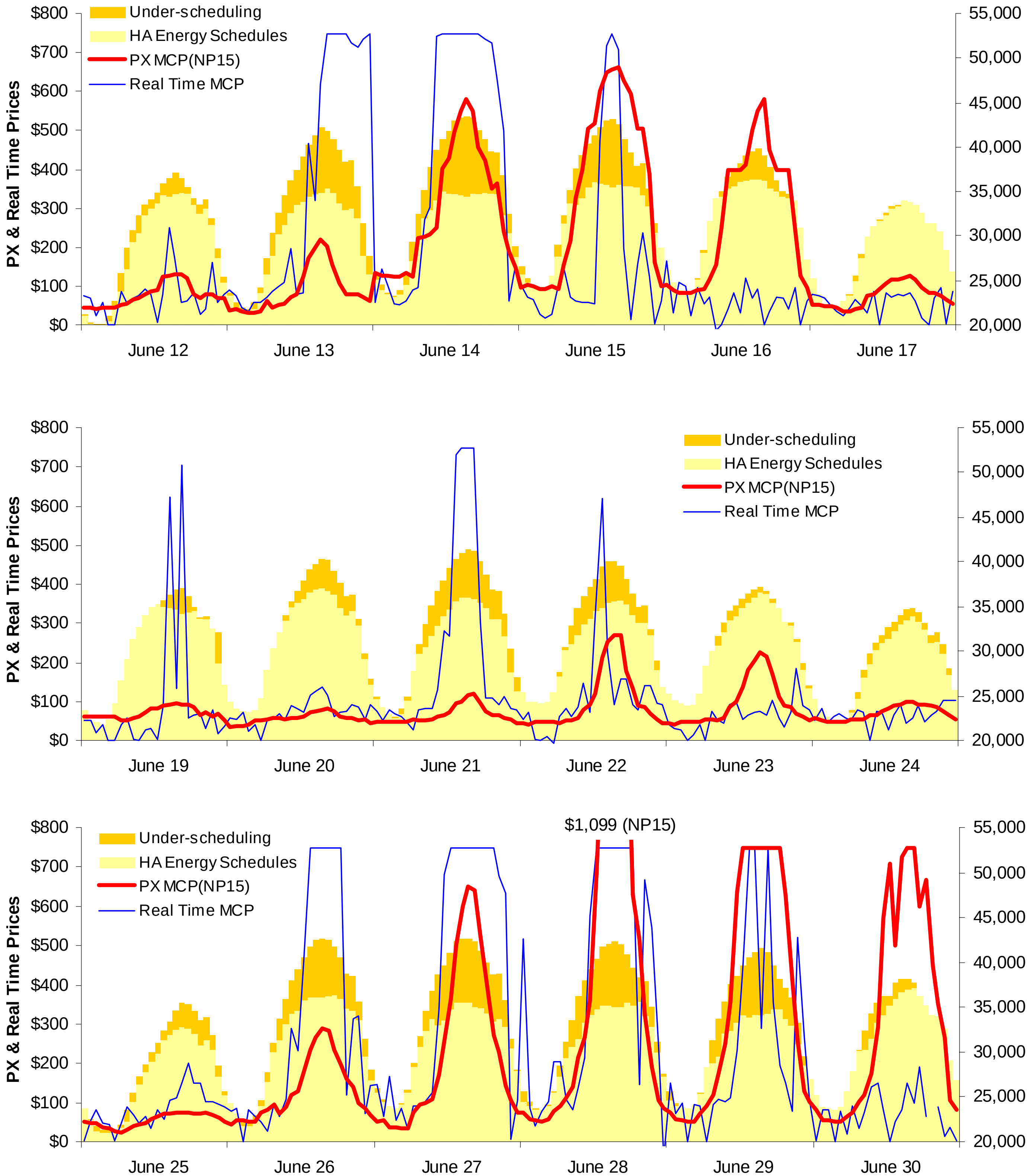


Figure 6. PX and Real Time Energy Prices (June Heat Waves)



- The higher PX prices during that June 26-30 heat wave appear to be due, at least in part, to an adjustment of demand bidding in the PX reflecting a willingness to pay significantly higher prices in the Day Ahead market. This adjustment may be attributable to the higher cost of demand met in the real time market due to the combination of higher real time prices, plus significant deviation replacement reserve charges. These issues are discussed in other sections of this report.
- Real time prices hit the $750 price cap at total of 24 hours over the four-day period from June 26-20, before dropping on June 30.

III. Total Market Costs

This section provides an estimate of the financial magnitude of the May and June price spikes based on the amount of load served and prices in different energy and ancillary service markets. For this analysis, we estimated total market costs as follows:

- Costs of scheduled energy (which includes loads and generation scheduled in the Day Ahead PX as well as bilateral markets or "self-scheduled" loads/generation) are estimated based on the total Hour Ahead schedules valued at the market clearing prices in the PX Day Ahead market.[6]
- Costs of energy met in the real time market are estimated based on the difference between actual loads and scheduled loads, multiplied by the real time prices.[7]
- Costs of Replacement Reserve, which accounted for a very high portion of ancillary service costs in June, were assumed to be allocated entirely based on unscheduled loads met in the real time market. [8]
- Costs of all other ancillary services were assumed to be allocated based on actual loads.

Figure 7 summarizes total daily costs for each of these four categories from the period May 18 through July 5. Figure 8 shows a more detailed breakdown of costs in the ISO markets (real time energy, replacement reserve, and other ancillary services) for this same time period. As shown in Figures 7– 9:

- Over 73% of total market costs during the month of June were incurred during the peak hours of the eight days from June 13 –16 and June 26-30.
- The portion of ISO market costs incurred during the heat waves of June 13-16 and June 26-30 was even greater, with over 87% of total real time energy and ancillary service market costs incurred during these two heat waves.

Figure 9 and Table 1 provide a summary and additional discussion of total monthly costs by each category, including a breakdown of scheduled energy costs based on the approximate portion load actually scheduled in the PX versus other schedule co-ordinators. As shown in Figure 9 and Table 1, California's energy and ancillary service markets represented a $3.6 billion market in June, with the ISO real time and ancillary service markets accounting for about $765 million, or approximately 21% of total market costs during June.

Table 2 shows a calculation of the extent to which price increases in June may be attributed to higher gas prices relative to the summer months of 1999 (June to August). As shown in Table 2, at least 20% of the increase in total cost per MWh of load served in June 2000 relative to the summer months of 1999 may be directly attributable to the increase in gas prices over the last year. It should be noted that this example is based on what may be a conservative estimate of the average heat rate of the marginal unit needed to meet demand, since during many of the hours when prices were highest in the ISO system, resources with much higher heat rates were needed to meet demand. For instance, based on an average heat of 16,000

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[6] In effect, this approach values all loads and generation that is scheduled through final Hour Ahead schedules at the PX price. In practice, the actual price of a portion of this generation may depend on pre-agreed contract prices and other bilateral arrangements.The average of the zonal prices in SP15 and NP15 is used to approximate the amount of load met at each zonal price.

[7] See Footnote 5.

[8] In practice, a relatively small portion of Replacement Reserve that was not procured as Deviation Replacement Reserve in June may in fact be billed based on total load, rather than unscheduled deviations. We did not attempt to exactly replicate the actual allocation of these costs in the ISO settlement process.

MMBTU/MWh the price increase in June due to higher gas prices may reach $35, or about 27% of the price increase relative to summer 1999.

Figure 7. Total Daily Energy and Ancillary Service Market Costs (May and June Heat Waves)

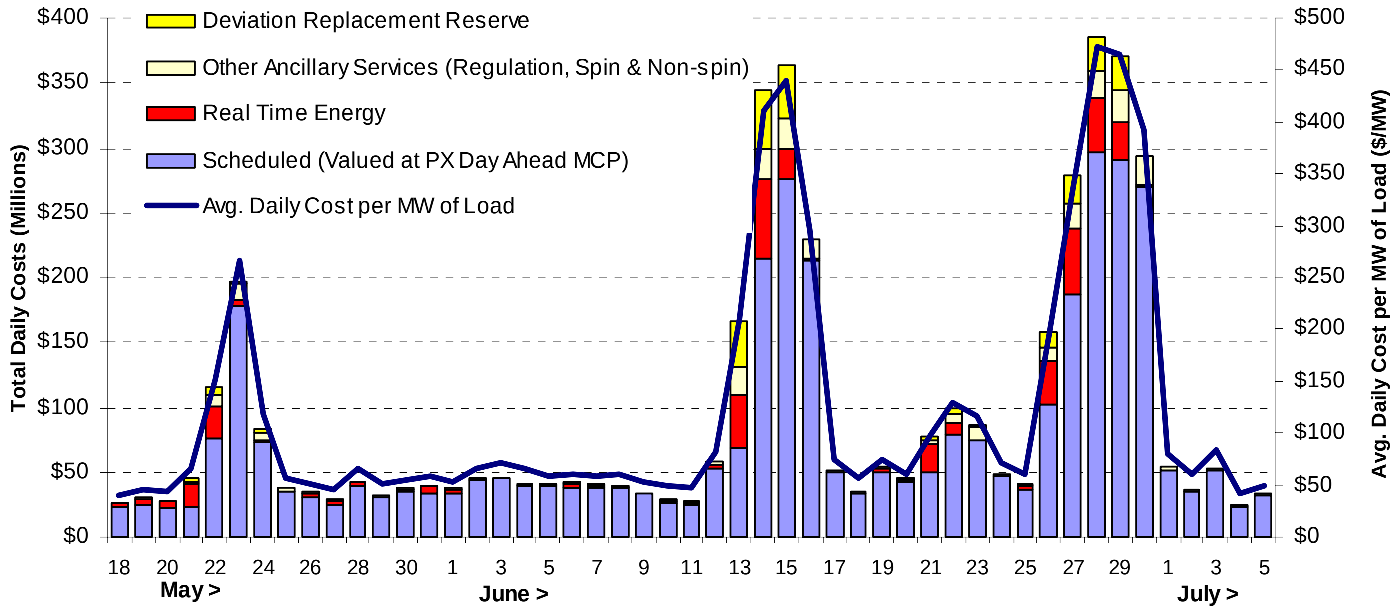


Figure 8. Total Daily ISO Real time and Ancillary Service Market Costs (May and June Heat Waves)

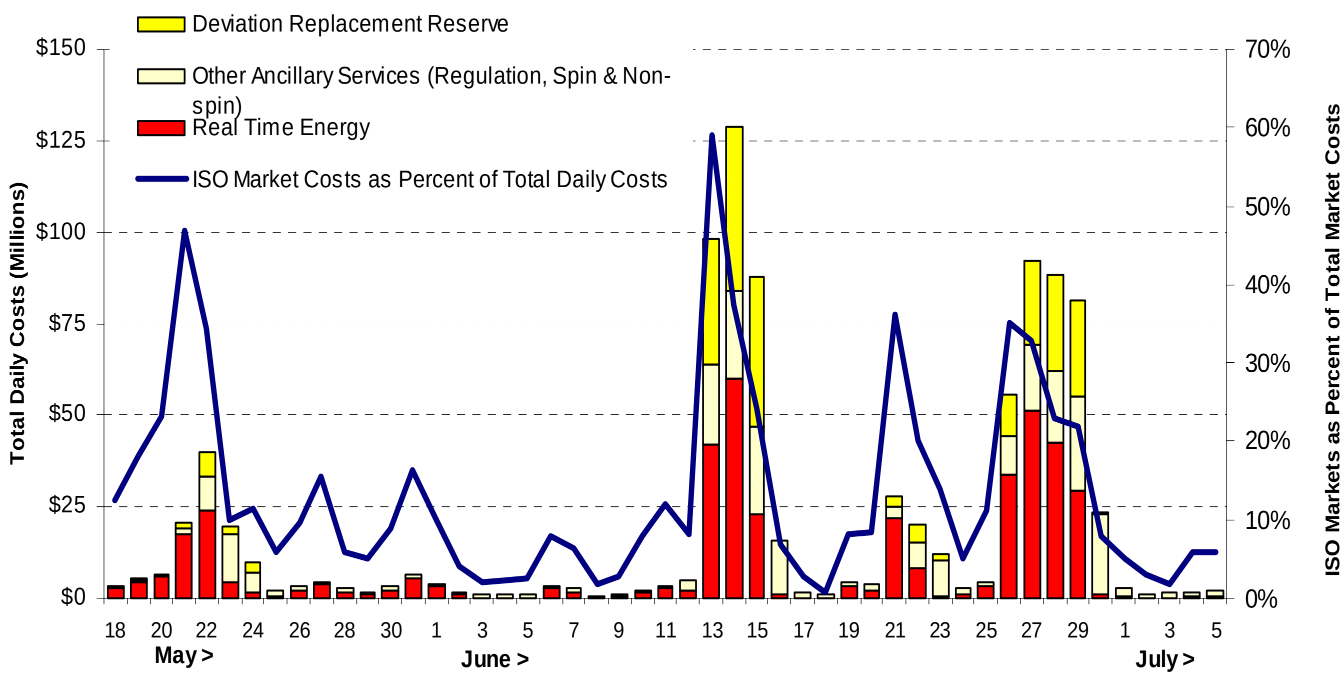
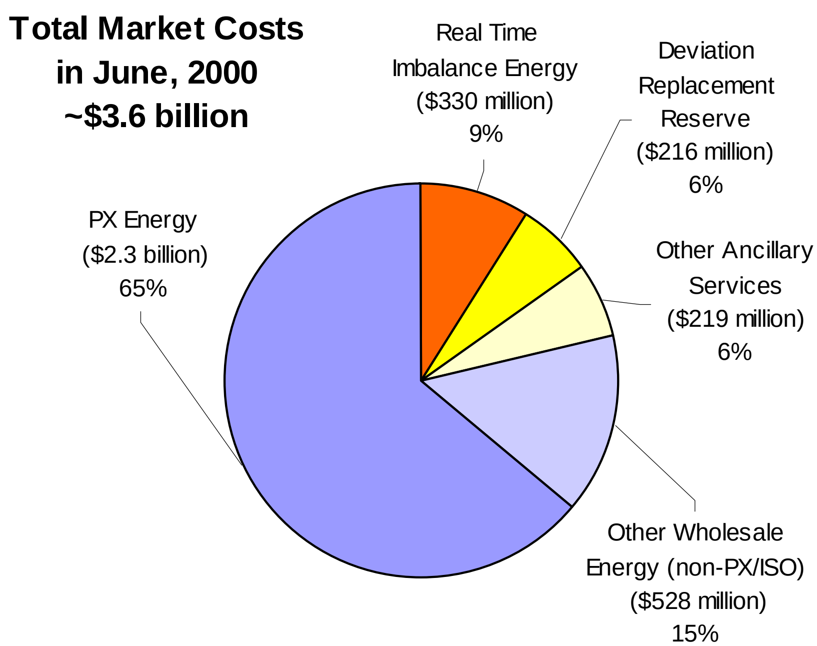


Figure 9. Total California Energy Market Costs, June 2000



California's energy and ancillary services markets represented a total market value of up to $3.6 billion in June 2000. In the figure above, total market costs are estimated based on total loads and schedules in the ISO system, valued at prices in the major PX and ISO energy and ancillary services markets. Additional details of how overall costs were estimated based on overall system loads, hour ahead energy schedules, and market clearing prices and quantities in the PX and ISO markets are provided in the text of this report and in Table 1. To the extent that some energy was "pre-purchased" by buyers through bilateral transactions and forward market hedging (such as the PX's block forward markets), actual costs paid by buyers would be lower than the $3.6 billion "value" of California's energy and ancillary service markets at market clearing prices.

The PX Day Ahead market accounts for the largest portion of California's energy market, representing a total market of $2.3 billion (or 65% of total market costs) in June. When valued at PX Day Ahead price, other energy scheduled in the Day Ahead and Hour Ahead markets (which includes bilateral transactions and municipal loads) represents a total market value of over $500 million in June.

The ISO real time market accounted for about $330 million in costs, or about 9% of the total wholesale market in June. Another $216 million (or about 6% of total market costs) was incurred due to replacement reserve capacity purchased by the ISO to ensure reliability in the face of significant underscheduling of loads and generation in the forward markets during many peak hours. The cost of replacement reserve purchased due to underscheduling is allocated based on uninstructed deviations in real time, which includes loads that were not scheduled in the Day Ahead or Hour Ahead market. Other ancillary services, which are billed based on metered demand, accounted for about another $219 million (or about 6% of total market costs).

Table 1. Total Market Costs per MWh of Load, June 2000

	Total Costs (Millions)	Total MWh	Avg $/MWh
PX Day Ahead [1]	$2,301	17,219,831	$134
Other [2]	$528	3,518,567	$150
Scheduled Energy [3]	$2,830	20,738,398	$136
Real Time Imbalance Market [4]	$330	867,447	$381
Replacement Reserve [5]	$217	867,447	$250
Real Time Energy (Effective Price) [6]	$547	867,447	$631
Total Energy (Weighted	$3,377	21,605,845	$156
Other Ancillary Services [7]	$219	21,605,845	$10
Total Average Price	$3,596	21,605,845	$166

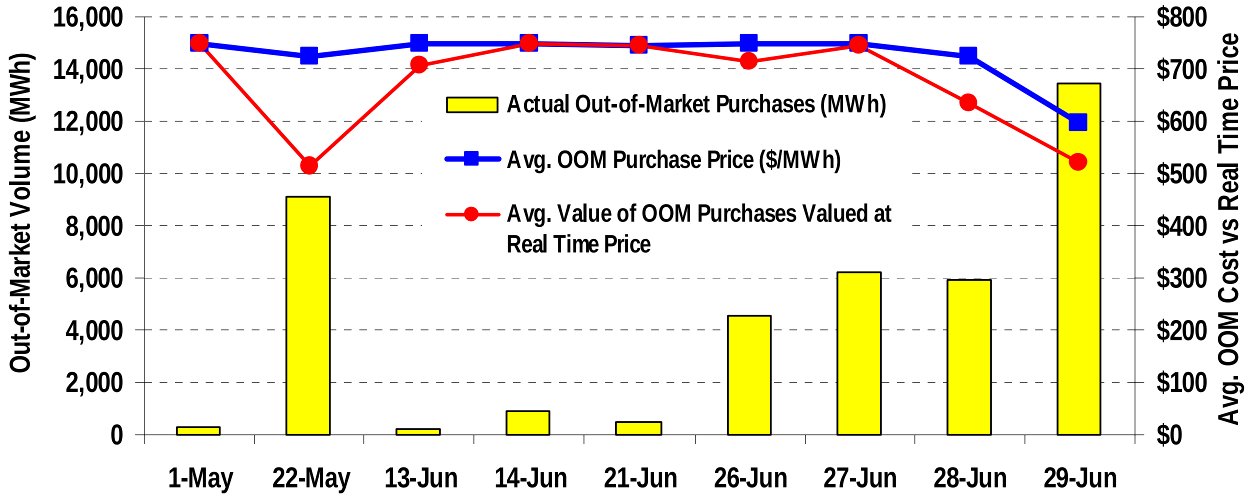
[1] PX MCQ x Avg
[2] (Final HA Scheduled - PX UMCQ) x Avg PX
[3] Final HA Scheduled x Avg PX
[4] (Actual Load - Final HA Schedule) x Avg PX
[5] Assumes Total Replacement Reserve Cost
to Deviations between Actual and Hour Ahead
[6] Effective Price of Unscheduled Energy (Real Time Price + Replacement Rese
[7] Regulation, Spin and Non-spin (MCP x MCQ, Day Ahead + Hour

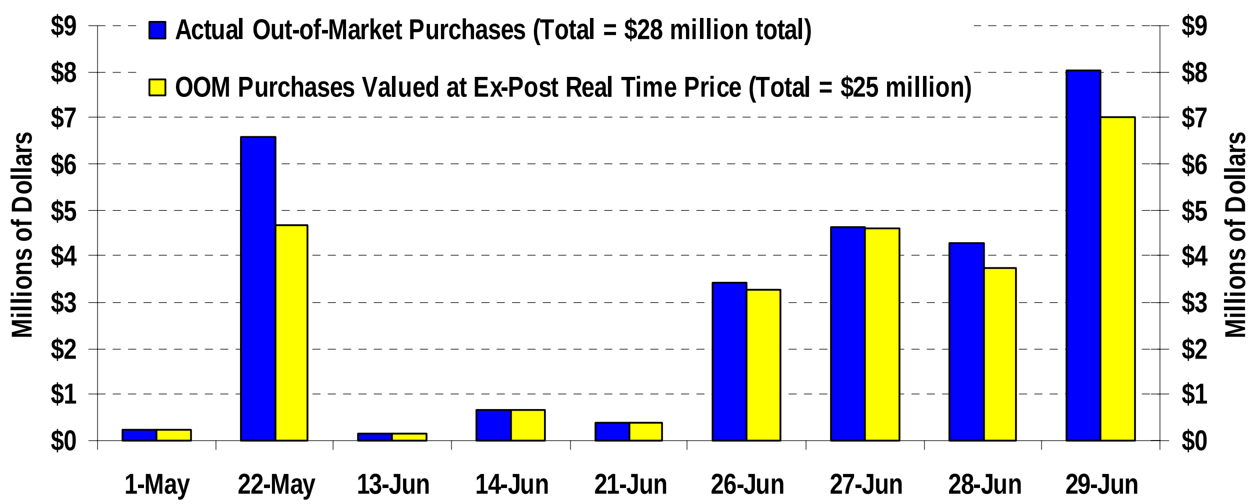
Table 2. Potential Increase Due to Gas Price

	Summer 1999	June 2000	Difference
Average Daily Gas Price [1]	$2.56	$4.73	$2.17
Average Marginal Heat Rate [2]	12,000	12,000	
Marginal Fuel Cost	$31	$57	$26
Average Total Cost [3]	$36	$166	$130
Increase in total cost per MWh of load due to Gas Price [4]			20%

[1] Average daily spot market price in Northern California
[2] Assumption of average heat rate of marginal unit needed to meet demand.
[3] Includes energy and ancillary service costs, as shown Table 1.
[4] $26 increase due to gas price ÷ $130 increase in total costs oer MWh of load served. Under the assumption of an average peak hour heat rate of 16,000 MMBtu, the same calculations show that the price increase in June due to gas prices may be as high as $35, or about 27% of the price increase relative to summer 1999 months.

Figure 10. Out-of-Market Purchases





The charts above show out-of-market purchases by the ISO during the months of May and June. Over this period, about 60% of the energy purchased out-of-market by the ISO was at a pre-agreed price equal to the $750 price cap in effect during May and June. About 10% of out-of-market energy was procured at a price of $750 during hours when the real time price hit the $750 price cap through agreements under which suppliers were paid the ex post real time price. The remaining portion of real time energy procured out-of-market was at bid or pre-agreed prices less than $750. Overall, the average price paid for energy out-of-market was $690, compared to a weighted average ex post real time price of over $600 during hours when this energy was procured. The difference in average price paid for out-of-market energy and weighted average value of this energy at the real time price is due primarily to the purchase of some energy out-of-market at the $750 level (made during the morning of several operating days) for hours when the real time ex post price ultimately fell below $750.

As shown in Figure 10, which provides a summary and discussion of out-of-market purchases by the ISO during May and June, out-of-market purchases accounted for a relatively small portion of total real time energy costs over these months. During May and June, out-of-market purchases of energy to meet demand in the real time market totaled about $28 million, with a value of $25 million based on the corresponding hourly ex post real time price (see Figure 10 for more detailed discussion).

Figures 11 and 12 examine the issue of how the $3.6 billion in total market costs may ultimately affect different market participants and consumers. As shown in Figure 11:

- Publicly available data on the total volume of net sales in the PX block forward market for NP15 show that PG&E may have hedged up to about 1,100 MW in the block forward market in June and about 1,800 MW in the other summer months out of a limit of about 3,000 MW allowed by the CPUC.
- The net volume of sales in the SP15 block forward market indicates that SCE may have hedged about 1,750 MW of its 2,200 MW limit in June, and about 3,000 to 3,500 MW of its 5,200 MW limit for the months of July to September.

Figure 12 and the accompanying discussion provide information concerning how total market costs incurred in June could ultimately impact different customers, IOU shareholders, and other market participants. It should be noted that actual impact that price increases depends a variety of factors beyond the scope of this analysis, and that other entities in California are better able to assess these impacts. However, information in Figure 12 is provided in this report to assist other entities in making such assessments, and to provide a preliminary indication of the ultimate impact of the June price spikes in terms of these different groups. As shown in Figure 12:

- At least 34% of costs incurred by the state's major IOU's (PG&E and SCE) are paid, in effect, to themselves as a result of generation owned by these utilities.
- We estimate that another 6% of costs in June were hedged through 2,850 MW sold in the PX block forward markets. For this example, we have assumed that energy purchased in the NP15 and SP15 block forward markets was purchased by PG&E and SCE, respectively. The portion of amount of total market costs (previously shown in Figure 10) that was hedged by these purchases (shown in Figure 12) was estimated by multiplying the amount of energy purchased in the PX block forward market by the average value of this energy based on average PX prices during the 6 x 16 hour period covered in the block forward market ($172 MWh).
- Remaining costs for the state's two major IOUs are partially covered in the frozen retail rates currently charged to PG&E and SCE customers. For instance, while costs for unhedged energy procured by IOUs in June may average about 16.6 cents/kWh, retail rates for the major IOUs include approximately 6 cents/kWh for recovery of energy charges and CTC recovery. Consequently, to provide an indication of the portion of energy costs increases that may impact shareholders of the major IOUs, Figure 12 further reduces the total potential cost exposure of the major IOUs by the amount of these costs that are covered in current retail rates.[9]
- Due to the rate freeze, costs not hedged or recovered through frozen rates may ultimately have the effect of delaying repayment of the Competitive Transition Charge (CTC), and/or the ultimate level of CTC recovered by IOU's. As noted above, we estimated the portion of costs that may impact the CTC

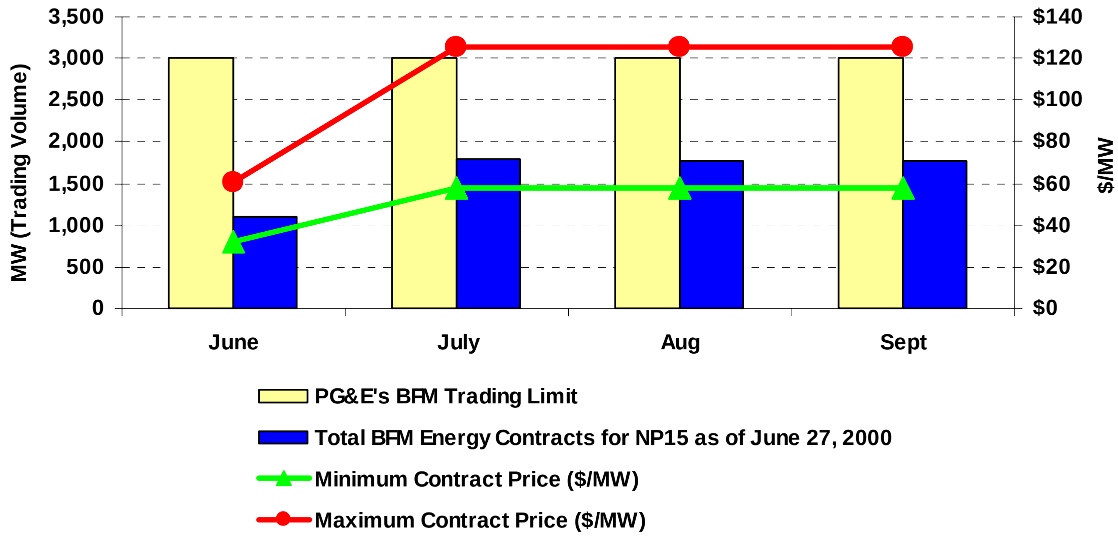
[9] Specifically, Figure 12 assumes that while the cost of unhedged energy procured by the state's major IUO in June averaged about 16.6 cents/kWh, retail rates for the major IOUs include approximately 6 cents/kWh for recover of energy charges and CTC recovery.

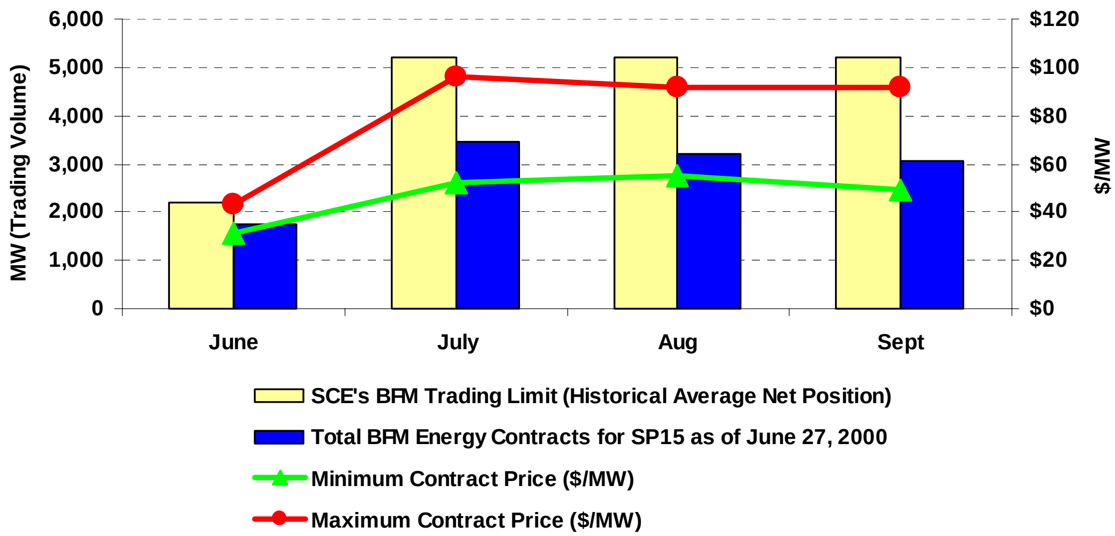
recovery based on the total market energy costs of PG&E and SCE not covered by either (1) estimated revenues from self-owned generation, (2) hedged by block market purchases, or (3) recovered in the frozen retail rates currently charged to PG&E and SCE customers. Results of this analysis are depicted in Figure 12 as “Potential Negative CTC Recovery”.

- Direct access customers, ESP and municipals are estimated to account for about 17% of total loads and costs. Many of these loads are likely to be covered by bilateral contracts, so that cost impacts between customers and Energy Service Providers (ESPs) depend on the nature of each contract and the extent to which supplies for these customers were hedged through forward contracts.

- SDG&E, which has repaid its CTC and is no longer under a rate freeze, is estimated to account for about 6% of total market costs in June.

Figure 11. Forward Market Hedging in the PX Block Forward Market

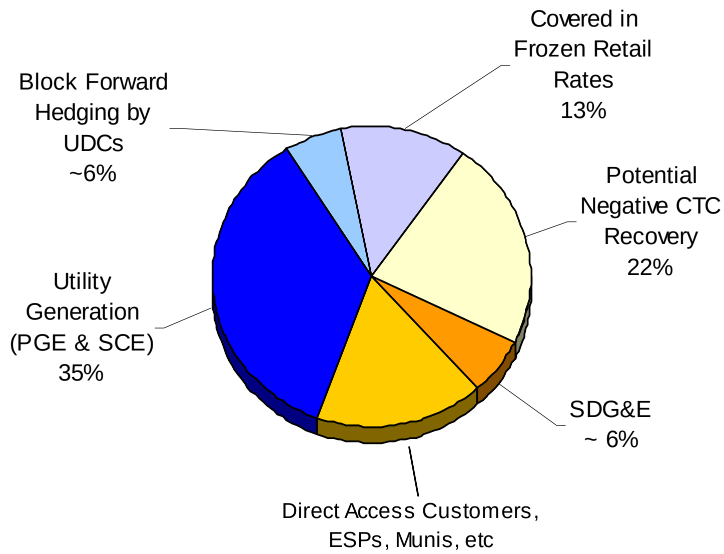




The ability of California's two major utilities (PG&E and SCE) to hedge against high prices in the PX Day Ahead by pre-purchasing energy in other forward markets is currently limited by CPUC regulations in terms of both the quantity they may hedge, as well as the markets in which they may participate. UDCs are required to make all forward market purchases through the PX's block forward market. In addition, PG&E and SCE were limited to block forward market purchases of about 3,000 MW and 5,000 MW, respectively, during the summer 2000 months. Block Forward market hedging limits were based on levels requested by utilities, and were designed to allow each utility to hedge it's average minimum load during the peak summer months.

As shown in the charts above, publicly available data on the total volume of net sales in the PX block forward market for NP15 show that PG&E may have hedged up to about 1,100 MW in the block forward market in June and about 1,800 MW in the other summer months out of a limit of about 3,000 MW allowed by the CPUC. The net volume of sales in the SP15 block forward market indicates that SCE may have hedged about 1,750 MW of its 2,200 MW limit in June, and about 3,000 to 3,500 MW of its 5,200 MW limit for the months of July to September.

Figure 12. How Are Market Costs Allocated Among Consumers, IOUs and other Market Participants?



The figure above shows an estimate of how total market costs incurred in June could ultimately impact different customers, IOU shareholders, and other market participants.

At least 35% of costs incurred by the state's major IOU's (PG&E and SCE) are paid "to themselves" as a result of generation owned by these utilities. In making this calculation, revenues from IOU generation was estimated based on actual market schedules and market clearing prices.

Another 6% of costs in June were hedged through 2,850 MW sold in the PX block forward markets. The portion of total market costs already covered or hedged by block forward market purchases was estimated in Figure 12 by valuing block forward purchases at the PX Day Ahead price.

Remaining costs for the state's two major IOUs are partially covered in the frozen retail rates currently charged to PG&E and SCE customers. For instance, while costs for unhedged energy procured by the two major IOUs in June may average about 16.6 cents/kWh, retail rates for the major IOUs include approximately 6.27 cents/kWh for recovery of energy charges and CTC recovery. Consequently, to provide an indication of the portion of energy cost increases that may impact shareholders of the major IOUs, Figure 12 further reduces the total "unhedged" costs incurred by the major IOUs by the approximate portion of these costs that are covered in current retail rates (~6 cents out of an average cost of 16.6 cents).

Due to the rate freeze, costs not hedged or recovered through frozen rates may ultimately have the effect of delaying repayment of the Competitive Transition Charge (CTC), and/or the ultimate level of CTC recovered by IOU's. For this reason, this portion of total market costs is labeled "Potential Negative CTC Recovery" in Figure 12.

SDG&E, which has repaid its CTC and is no longer under a rate freeze, is estimated to account for about 6% of total market costs in June. Direct access customers are estimated to account for about 17% of total loads and costs. Many of these loads are likely to be covered by bilateral contracts, so that cost impacts between customers and Energy Service Providers (ESPs) depend on the nature of each contract and the extent to which supplies for these customers were hedged in the forward markets.

IV. Underscheduling of Loads and Supply

During June, the total amount of load and generation scheduled in the Day Ahead and Hour Ahead market consistently hit a plateau of about 35,000 MW, with any remaining load above this level being met in the real time imbalance market (see Figure 5 and 6 in previous section). Figure 13 summarizes the overall pattern of underscheduling during the month of June at different load levels.

Figure 14 and the accompanying text summarize several of the key factors creating large under-scheduling of loads and generation in the ISO's real time imbalance market. Recent PX market prices and volumes -- as well as sample aggregate supply and demand curves released by the PX -- indicate that despite recent "shifts" in aggregate demand (reflecting an increased willingness-to-pay in the forward markets), the ability of buyers to increase purchases in the PX Day Ahead markets is severely limited by the nearly vertical slope of the PX supply curve around the 30,000 MW level. Due to the nearly vertical slope of supply offered in the PX at this level, any outward shift in demand simply increases the Market Clearing Price (MCP) significantly, with a minimal increase in the Market Clearing Quantity (MCQ). As a result, large buyers have an incentive to minimize overall costs by limiting their purchases in the PX market when overall aggregate demand intersects supply at this nearly vertical portion of the supply curve. Thus, the massive underscheduling that is occurring during high load hours represents a failure of both supply and demand to clear and schedule in the forward markets.

Within the current design of California's energy markets, the ability of buyers to limit the prices they are willing to pay in the forward energy markets and shift demand into the real time imbalance market represents one of the major ways that large buyers can limit overall costs and defend against market power. Other tools for "defending" against high prices due to both market power and scarcity include demand elasticity, and the ability of buyers to procure supply in forward markets and through bilateral contracts. However, the ability of buyers to utilize these tools is currently limited significantly due to regulatory constraints and the relatively immature nature of California's recently deregulated energy market.

One option that is sometimes suggested for reducing the reliability problems associated with under-scheduling of loads and generation is to simply require all (or a very high percentage) of actual expected loads and available generation to be scheduled in the forward markets. As illustrated in Figure 15 and the accompanying discussion, this is likely to simply cause the PX price to clear at $2,500 during many hours when prices now clear in the $500 to $750 range.

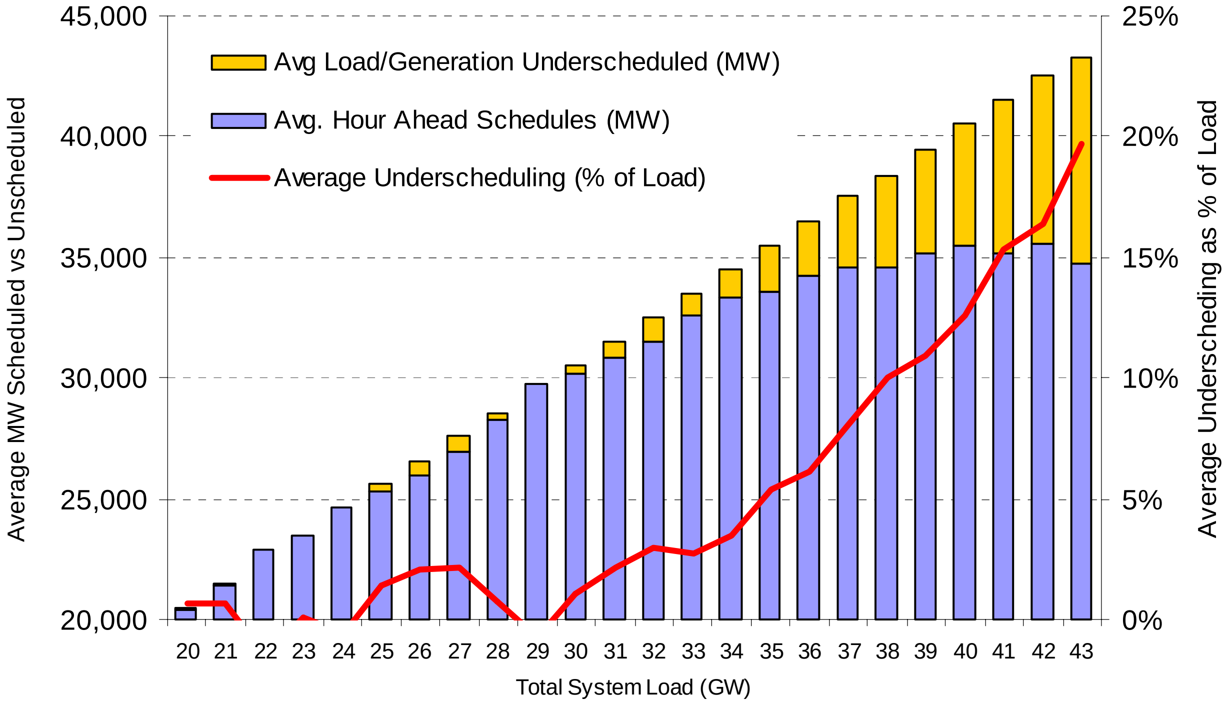
Another market design feature that may prevent buyers from paying the higher prices necessary to purchase and schedule additional load in the PX Day Ahead market results from the combination of:

(1) a requirement by the PX that adjustment bids for decremental demand submitted with initial schedules for load purchased in the PX be higher than the PX unconstrained price, and

(2) the ISO's requirement that adjustment bids not exceed the current $500 price cap (set at $750 during the June price spikes).

In combination, these two constraints can expose buyers in the PX to extremely high constrained prices in the event of congestion. For instance, if the unconstrained price is higher than the ISO's price cap, buyers in the PX are unable to submit adjustment bids which meet both the PX requirement that adjustment bids be *higher* than the unconstrained price, as well as the ISO's requirement that adjustment bids be *lower* than the ISO's price cap. This creates the risk that in the event of congestion, insufficient adjustment bids would

Figure 13. Average Underscheduling of Loads and Generation by System Load Level (June, 2000)



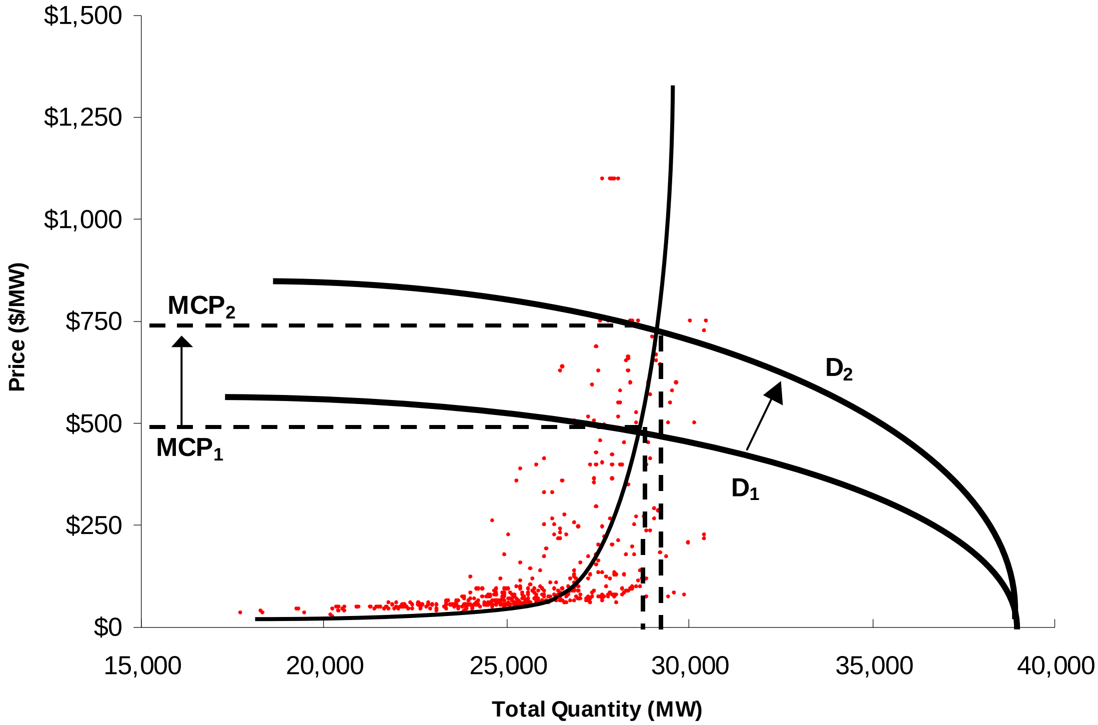
As previously shown in this report, the total amount of load and generation scheduled in the Hour Ahead Schedules consistently hit a plateau of about 35,000 MW, with any remaining load above this level being met in the real time imbalance market (see Figures 5 and 6). The 35,000 MW plateau of load and generation scheduled in the Day Ahead and Hour Ahead markets represents a maximum of about 30,000 MW scheduled in the Day Ahead PX market, plus a maximum of approximately 5,000 MW scheduled during peak hours from other Schedule Co-ordinators (SCs). Loads and generation scheduled by other SCs includes municipals, direct access customers, and other non-IOU loads and generation.

The figure above summarizes the average amount of underscheduling at different system load levels in June, in terms of total average MW (represented by bars charted on left axis) and as percentage of total system loads (represented by the line charted against the right axis).

Underscheduling of loads and generation in June was minimal below 30,000 MW, and averaged less than 5% of total loads up to load levels of about 35,000 MW. However, virtually all load and generation over 35,000 MW unscheduled in the Day Ahead and Hour Ahead markets.

The average amount of real time energy imbalance climbed from about 10% of total system loads at 38,000 MW, up to about 20% of total system peak loads (or nearly 9,000 MW) during hours when system load exceeded 43,000 MW. When system loads peaked at 43,447 MW on June 16 (Hour 16), total loads exceeded final Hour Ahead schedules by 9,064 MW, or about 21% of total system load.

Figure 14. Illustrative Example of Supply and Demand in PX Day Ahead Market



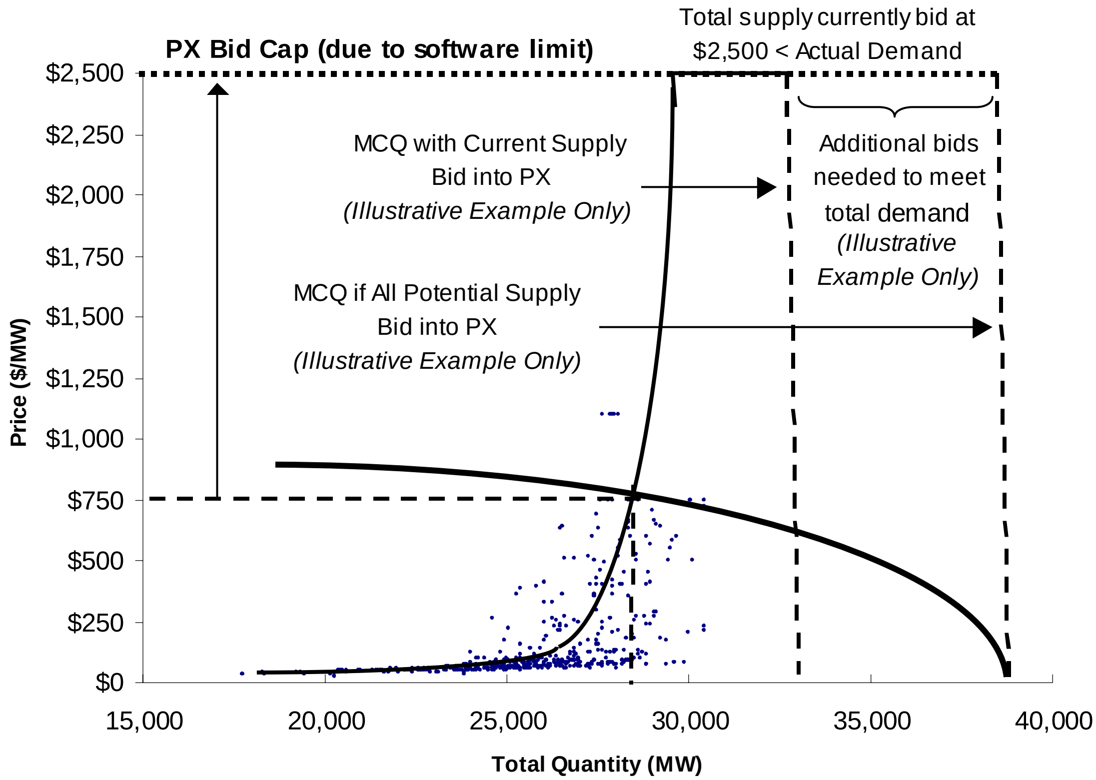
The figure above illustrates several of the key factors creating large under-scheduling of loads and generation in the ISO's real time imbalance market. Due to the very steep slope of the PX supply curve around the 30,000 MW level, any outward shift in the demand curve (representing an increased willingness of one or more buyers to purchase energy at relatively high prices) results in a significant increase in the Market Clearing Price (MCP), but only a small increase in the Market Clearing Quantity (MCQ).

Since the MCP is applied to the entire quantity purchased in the PX Day Ahead, large buyers have an incentive to limit their demand (or at least the portion of demand bid at very high prices) when the overall aggregate demand curve is intersecting the supply curve within this steeply sloped (almost vertical) portion of the PX supply curve. Although this sometimes requires a large portion of demand to be met in the real time market at potentially higher prices, this strategy limits overall costs paid by large buyers.

Within the current design of California's energy markets, the ability of buyers to limit the prices they are willing to pay in the forward energy markets and to shift demand into the real time imbalance market represents one of the major ways that large buyers can limit overall costs and defend against market power. Because of the nearly vertical slope of the PX supply curve at the 30,000 MW level, the massive underscheduling that is occurring during high load hours represents a failure of both supply and demand to "clear" and schedule in the forward markets. Figure 15 provides additional discussion of this issue.

In this illustrative example, the shape of the PX supply and demand curves is approximated based on actual data for several hours in June recently released by the PX (see Footnote 2), as well as publicly available data on the Market Clearing Price and Quantity in the PX Day Ahead market during peak hours in June (represented by red dots in the figure above). Actual aggregate PX demand and supply curves are only released after a six-month lag period.

Figure 15. Why Not Simply Require Load to Be Scheduled in the Forward Market?



One option that is sometimes suggested for reducing the reliability problems associated with under-scheduling of loads and generation is to simply require all (or a very high percentage) of actual expected loads and available generation to be scheduled in the forward markets.

The figure above illustrates several of the numerous problems with this approach. First, it must be remembered that over the short-term, many buyers (including California's major UDCs) are currently limited in their ability to meet demand by purchasing through the entire range of forward markets, ranging from regional futures and spot markets, to "traditional" bilateral contracts with individual suppliers. As a result, the state's UDCs must – over the short-run at least – continue to look to the PX Day Ahead market to meet a large portion of their demand.

Demand bid curves recently released by the PX suggest that the amount of demand currently being bid into the PX during peak hours meets or exceeds total actual loads, but that much of this demand is simply bid at a relatively low price so that it is very unlikely to clear under current market conditions (see Footnote 3, page 2). In order to ensure that their demand is scheduled in the forward markets, buyers would need to bid their total expected net demand into the PX as "price takers" (i.e. at the maximum bid price of $2,500/MW allowed for both supply and demand bids due to the PX's software). Unless a lower bid cap was placed on the PX market (and some way of requiring generators to bid capacity into this market was established), this would simply cause the PX price to clear at $2,500 during many hours when prices now clear in the $500 to $750 range.

Supply bid curves recently released by the PX suggest that the amount of supply currently being bid into the PX even at the $2,500 level during peak hours is well below the total available supply (including imports) and the level of supply needed to meet total demand (see Footenote 2). However, additional supply may be attracted to the PX if virtually all demand was required to bid into the PX as "price takers" or at a price comparable to the potential opportunity cost of capacity in other ISO and regional markets.

be available to relieve congestion, so that the Default User Charge (DUC) equal to the IS0 price cap would be in effect. Under the Default User Charge, buyers are exposed to very high congestion charges of $500.

This feature of the market design represents the likely explanation for many hours in late June and late July when the PX market has clears slightly below the ISO's price cap (e.g. $749 or $499). This allows buyers to submit adjustment bids for decremental demand at a price slightly higher than the unconstrained price, which is still equal to or lower than the ISO price cap on adjustment bids.

The issue of the whether or not the adjustment bid cap should be modified or "unlinked" from the real time energy price cap requires careful examination, in order to avoid potential adverse affects which lead to the setting of a single price cap for both real time energy and adjustment bids.

Figures 16 through 18 provide an examination of underscheduling by UDC area, based on aggregate total Hour Ahead Schedules and Final Loads within each UDC area. Thus, data in Figures 16 through 18 include both IOU loads and other entities within each UDC area.

- As shown in Figures 16 through 18, the level of underscheduling is highest (in terms of total MW and as a percent of actual load) in the PG&E area, followed the SCE area, with a relatively small amount of underscheduling in the SDG&E area.
- This pattern may largely reflect the fact that the incentive for buyers to limit purchases in the Day Ahead Market is largely a function of each buyer's size: while larger buyers can have a very big impact on market clearing prices, smaller buyers have much less impact, and therefore have less incentive to limit purchases.
- In addition, it is important to note that smaller buyers benefit from this pattern, in that they are able to meet a relatively large portion of their demand in the PX market at lower prices due to the purchase strategies of larger buyers.

The following section of this report discusses the impact that purchases of large quantities of deviation replacement reserve at high prices often hitting the $750 price cap) appears to have had on under-scheduling of both load and generation during June.

Figure 16. Underscheduling By UDC Area

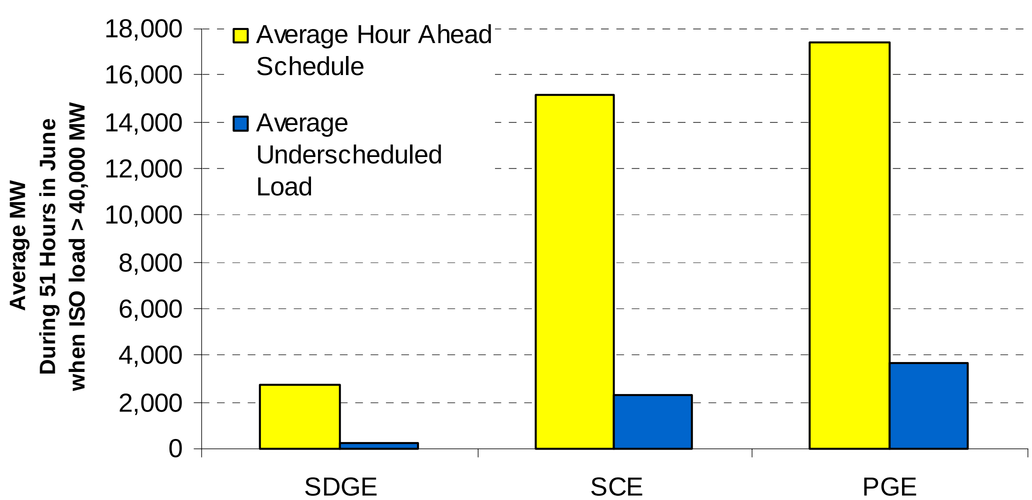


Figure 17. UDC Area Underscheduling By System Load Level

Underscheduling As a Percentage of Total UDC Area Load

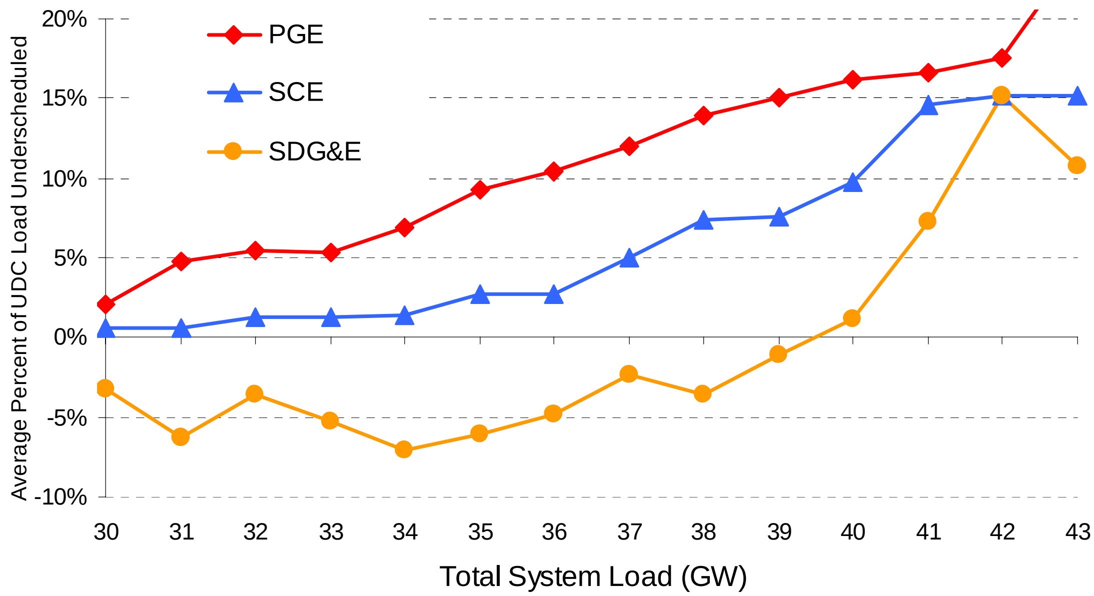
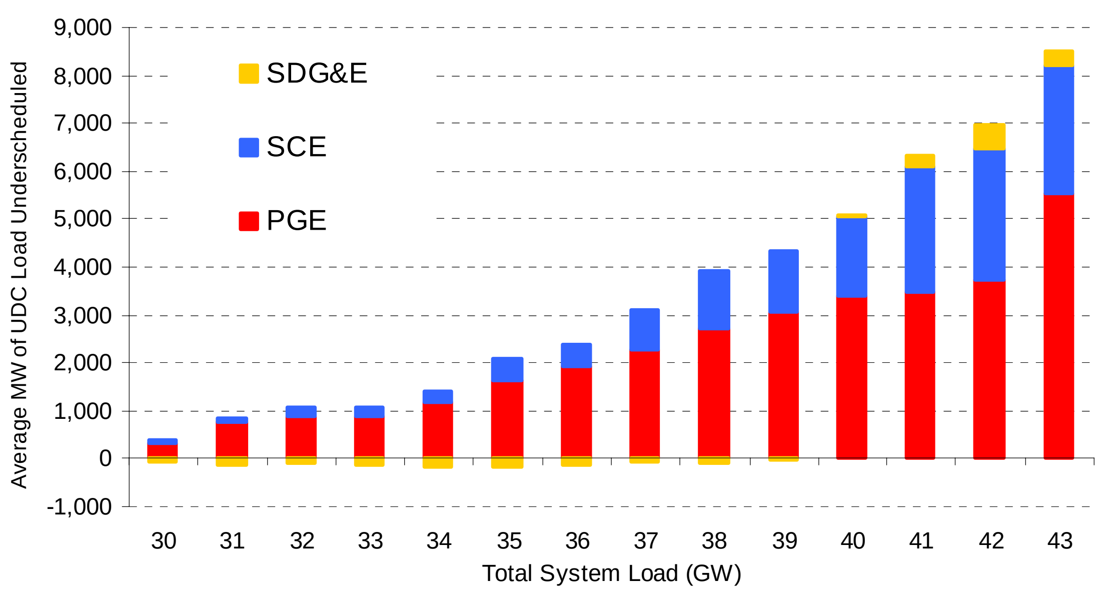


Figure 18. UDC Area Underscheduling By System Load Level

Total Average MW Underscheduled by UDC Area



V. Purchase of Replacement Reserve

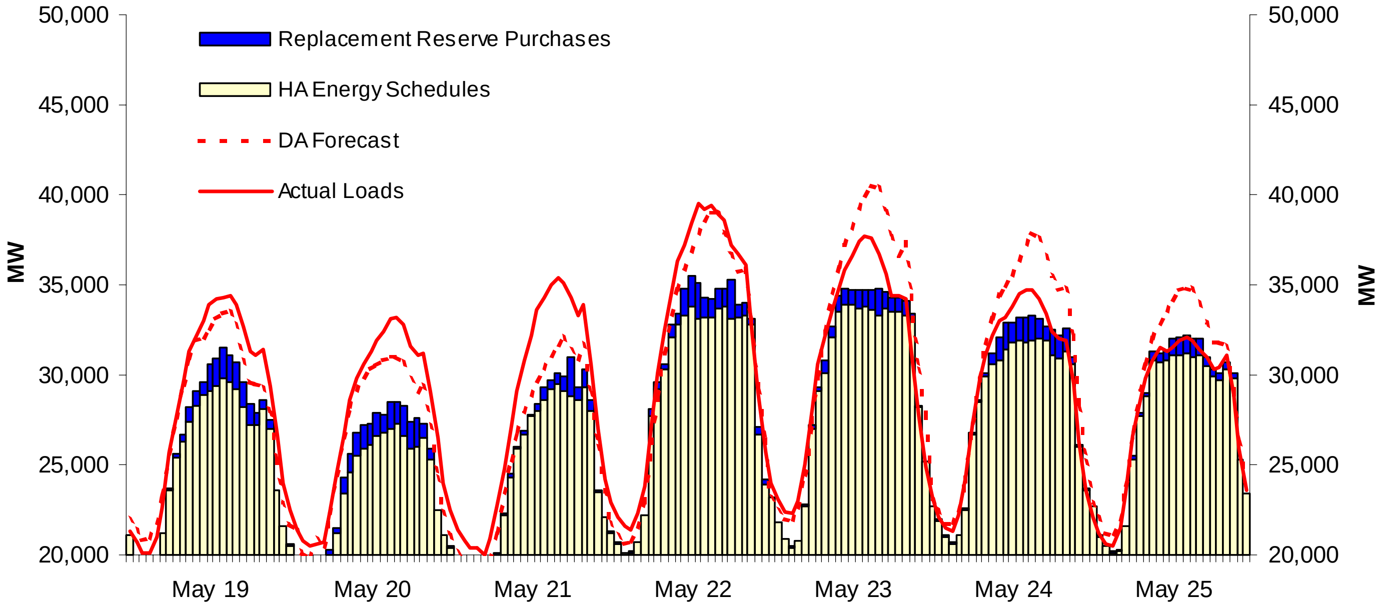
One of the key adjustments made by the ISO following the May 22 events was to implement an operational practice of defending against significant underscheduling of loads (and avoiding potential *out-of-market* purchases) by purchasing large volumes of replacement reserve capacity to narrow the gap between scheduled and forecasted loads. However, market performance during June indicates that the practice of purchasing replacement reserve based on the difference between scheduled and forecasted loads may have instead contributed to the development and/or perpetuation of a spiral of price spikes and underscheduling.

- Despite day ahead forecasted loads of up to 45,000 MW on the three day period from June 13-15, the amount of load and generation scheduled in the forward energy markets remained at approximately 35,000 MW. (See Figure 19)
- In contrast to the May 22 event, during the June 13-15 period the ISO purchased large quantities of Replacement Reserve (up to 7,000 MW) based on the difference between forecasted loads and generation/loads scheduled in the Day Ahead market, as shown in Figure 19.
- Purchasing this Replacement Reserve was intended to serve two purposes: (1) provide a firmer source of supply needed to meet projected demand (i.e. compared to supplemental energy bids, which have no obligation to deliver), and (2) provide an incentive for load to be scheduled in the forward market, in order to avoid being billed for the additional cost of this Replacement Reserve.
- The large volumes of Replacement Reserve purchased by the ISO accomplished this first objective by significantly reducing – but not entirely eliminating — the need to rely on "uncommitted" generation from supplemental energy bids.
- In practice, however, it appears the purchase of significant amounts of Replacement Reserve under the extremely tight supply and demand conditions existing during the June 13-15 period may have created an additional incentive for suppliers to withhold capacity from the Day Ahead PX market (by not bidding, or bidding at extremely high prices that buyers are unwilling to pay), and shift additional capacity into the Ancillary Services (particularly Replacement Reserve) and real time markets. As previously noted, suppliers can benefit from this strategy in two ways: they may be highly likely to receive a real time energy price higher than the Day Ahead PX price, and can receive both a capacity and energy payment by supplying Ancillary Services.

Figure 20 illustrates the effect that tight demand/supply conditions – coupled with the purchase and dispatch of large quantities of replacement reserves – may have had on PX market energy prices during the June 13-15 period. As shown in Figure 20, significant amounts of under-scheduling and real time price spikes occurred during both the May and June heat waves. However, PX Day Ahead prices rose significantly higher during the June heat wave, particularly in the days after large quantities of replacement reserves were purchased by the ISO.

Figure 21 compares the market clearing prices for Replacement Reserve during the May and June heat waves, along with the quantities of Replacement Reserves purchased. As shown in Figure 21, Replacement Reserves prices ranged from $250 to $500 during the peak hours of May 22 through 24, and spiked in the Hour Ahead market several hours on May 22-23 when the ISO procured significant amounts of Replacement Reserve in the Hour ahead market. During the June heat wave, however, the price of Replacement Reserve cleared at the $750 price cap during virtually all peak hours in both the Day Ahead

Figure 19. Purchases of Replacement Reserve
May vs. June Heat Waves



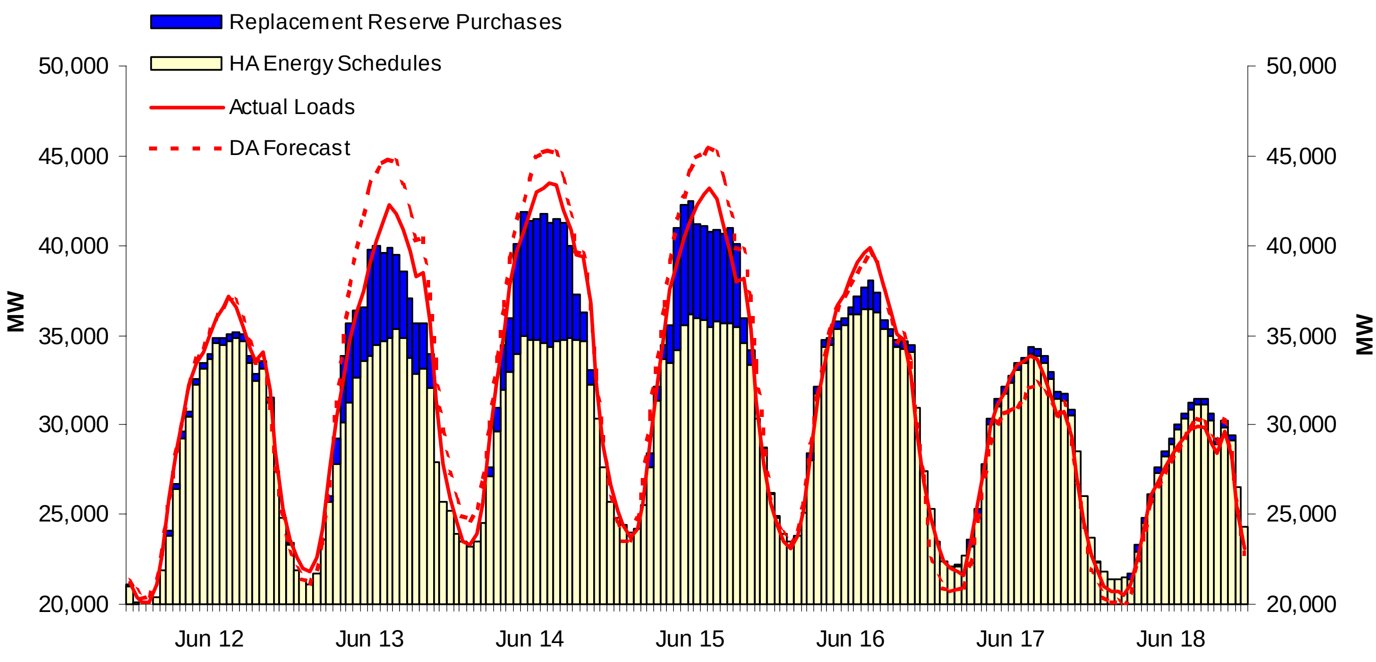
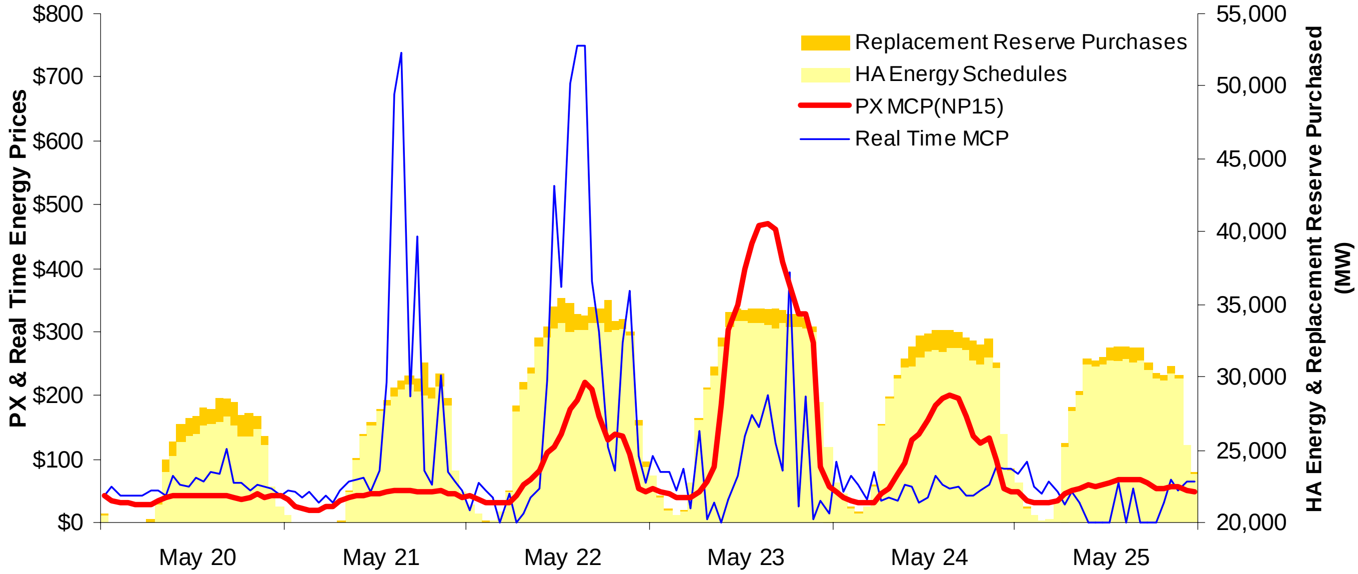


Figure 20. PX vs Real Time Energy Prices
May vs. June Heat Waves



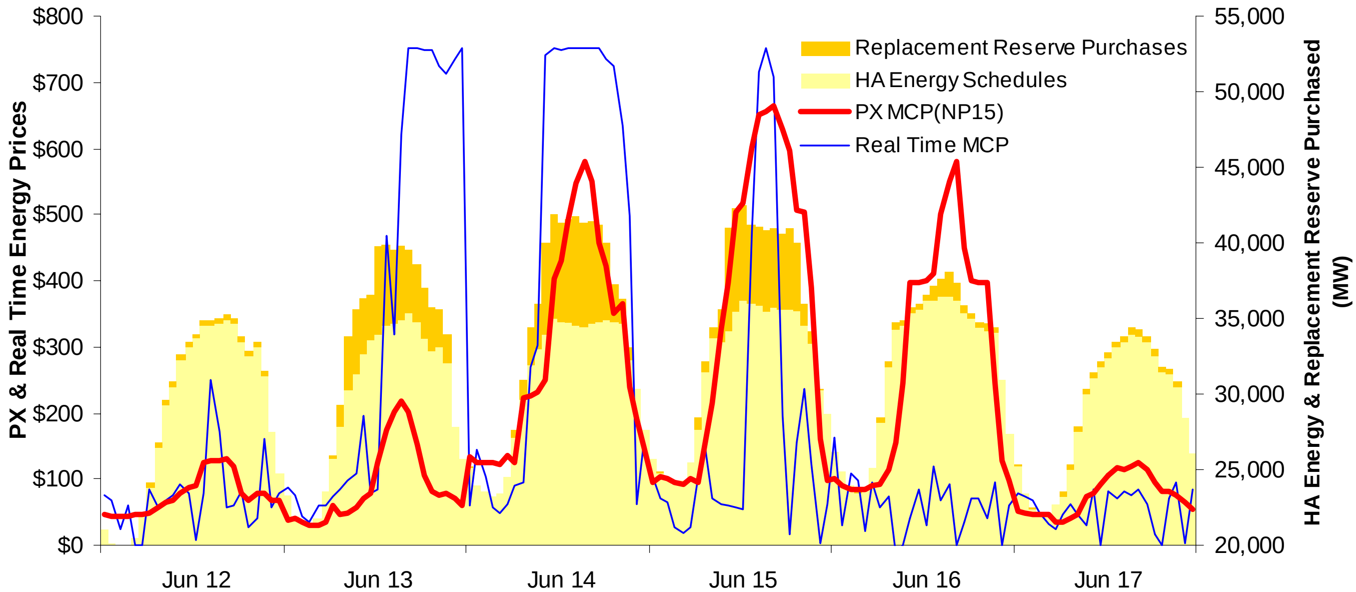
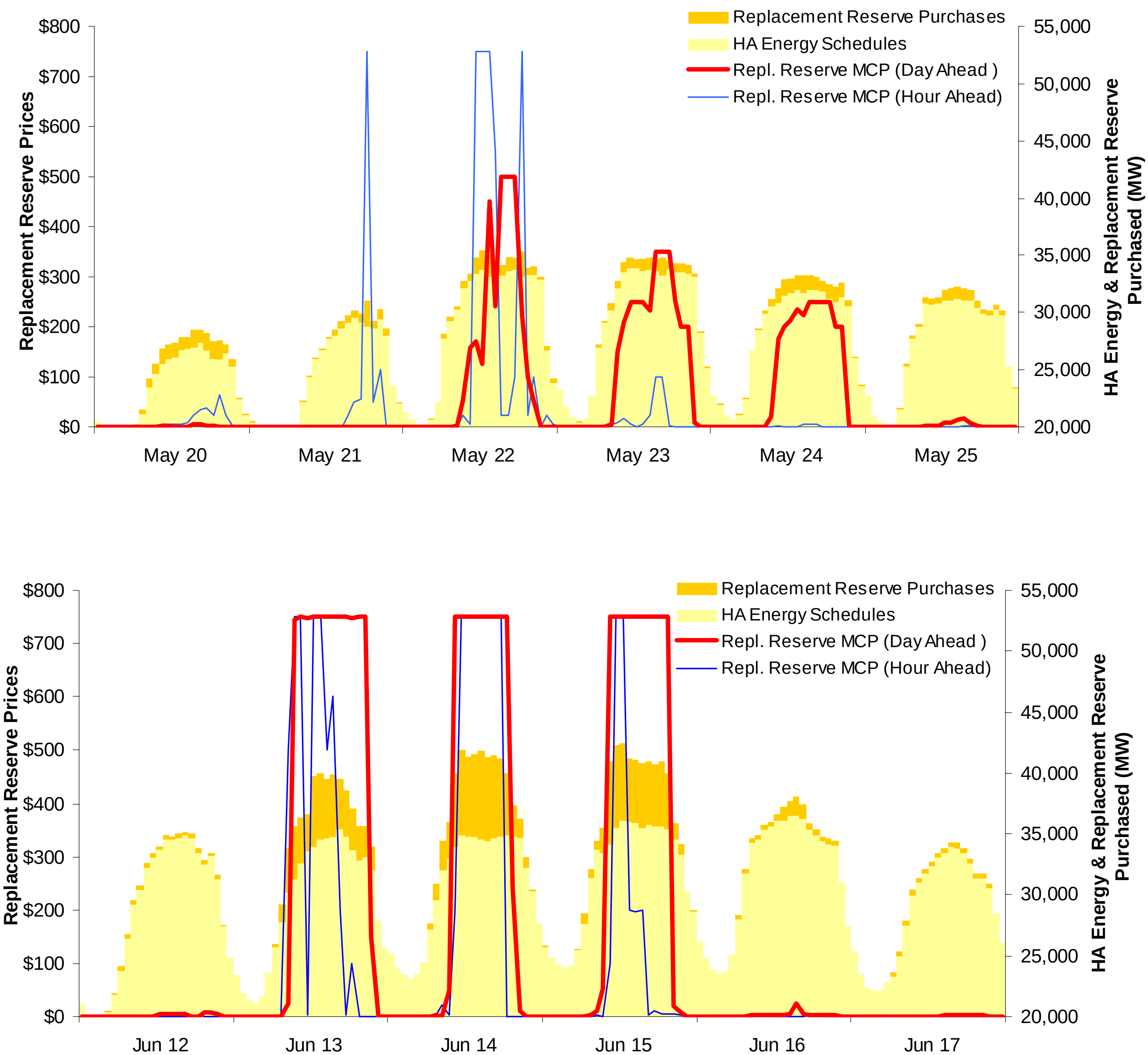


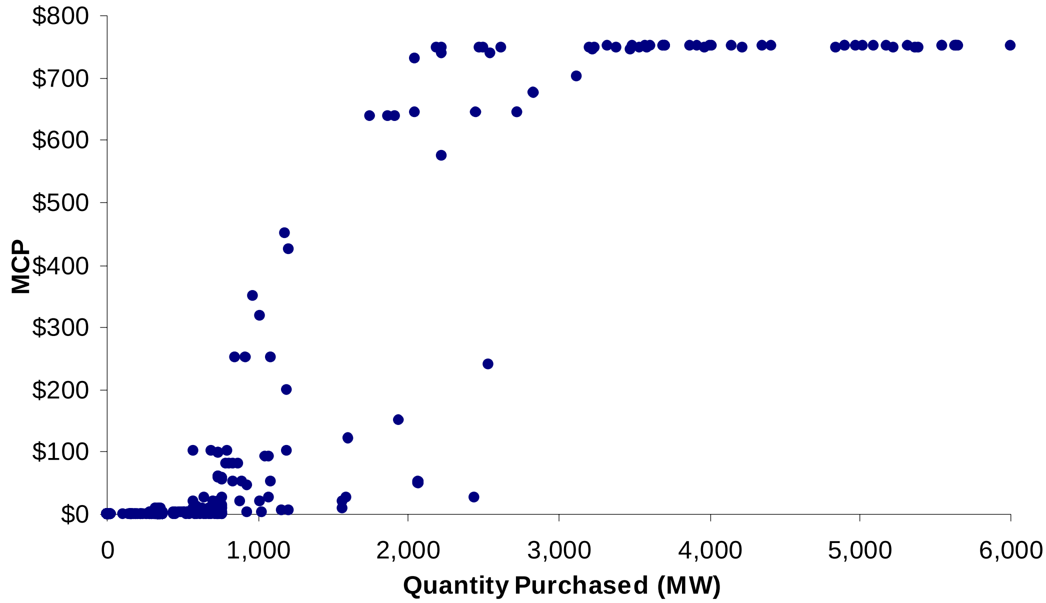
Figure 21. Replacement Reserve Purchases and Prices
May vs. June Heat Waves



and Hour Ahead Markets, as the ISO purchased virtually all supplies offered in both these markets over this three-day period. Figure 22 illustrates the steepness of the supply curve and relatively large quantities of Replacement Reserve purchased by the ISO during June. Additional information on the bid prices of supply offered in the Replacement Reserve Market is provided in Section VI.

The purchase of replacement reserves is intended, in part, to discourage buyers from under-scheduling in the forward markets. However, as discussed in Section III of this report, experience during the June heat waves suggests that – at least over the short run—there may be little buyers can do to purchase additional energy in the forward markets. From the perspective of large buyers, this creates an incentive to continue the careful balancing act of attempting to under-schedule some portion of demand in the forward energy markets in order to minimize overall payments. Figure 23 and the accompanying discussion summarize the overall impact that deviation Replacement Reserve purchases and prices had on effective prices in the PX Day Ahead and ISO real time market in June.

Figure 22. Replacement Reserve Purchases and MCP Prices (June)
Day Ahead Market



Hour Ahead Market

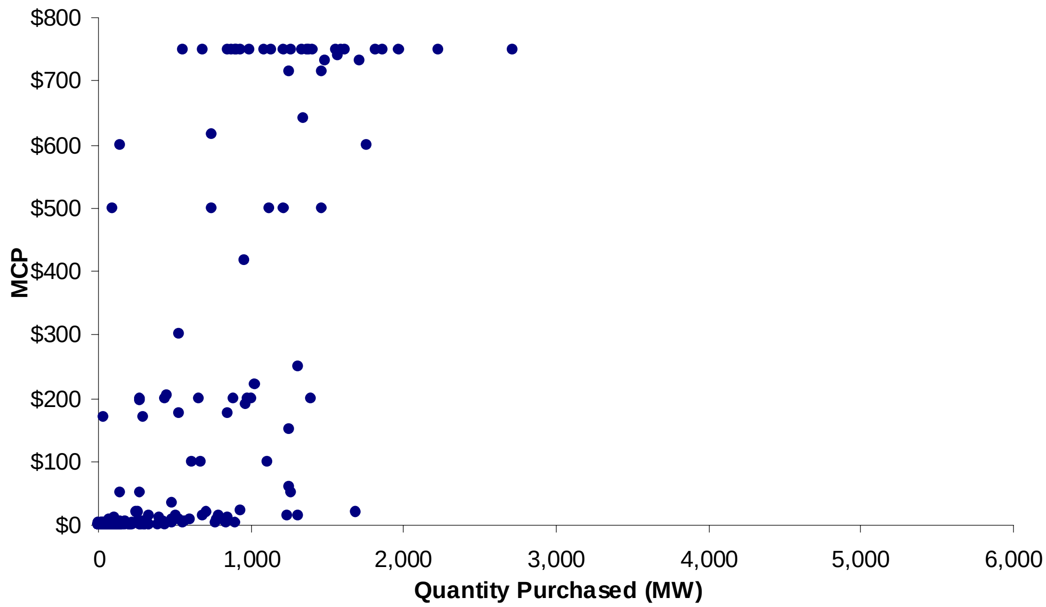
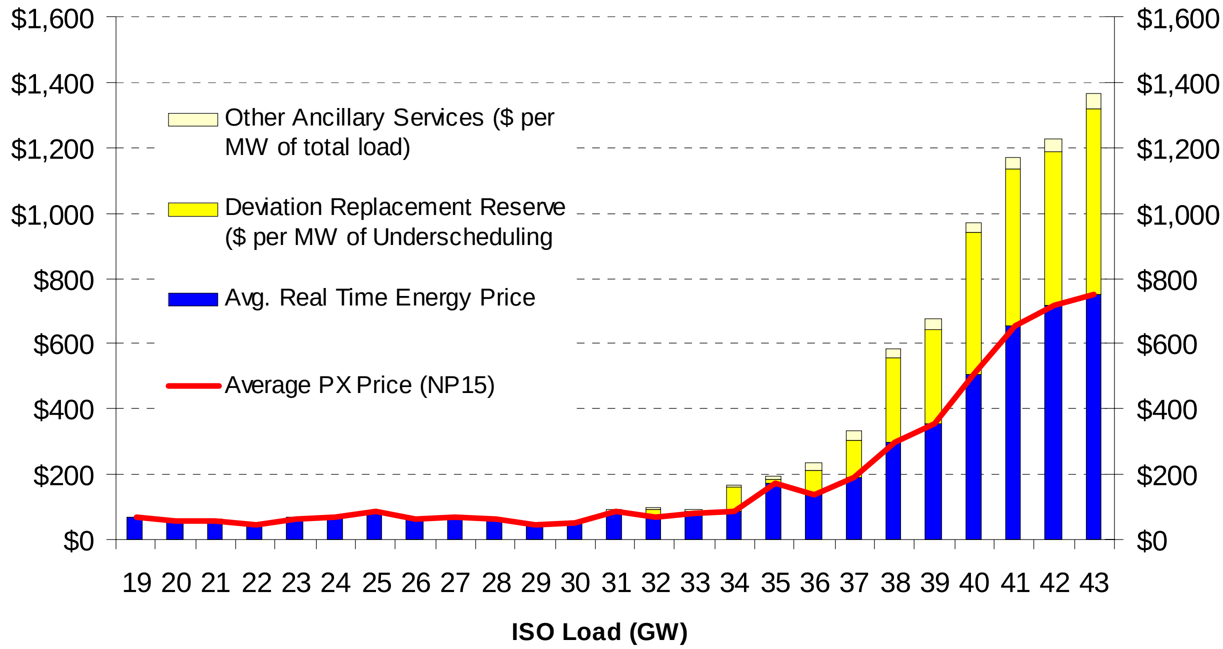


Figure 23. Replacement Reserve Purchases and MCP Prices (June) Day Ahead Market



The figure above compares the average PX Day Ahead price and ISO real time price at different load levels, along with the average estimated additional cost for load met in the real time market due to Deviation Replacement Reserve purchases. The average Deviation Replacement Reserve charge per MWh of load met in the real time market at each load level was estimated based on total Replacement Reserve costs, divided by the total difference between actual system loads and final hour ahead schedules. From the perspective of buyers, the effective cost of load met in the real time market includes both the real time energy price, plus Deviation Replacement Reserve charges. Thus, while average PX and real time prices tracked very closely at virtually all load levels in June, the effective price buyers in the real time market exceeded the PX price during load levels above 35,000 MW. At load levels of 40,000 MW and above, Deviation Replacement Reserve charges represent an estimated $400 to $500/MW, with average prices in both the PX and real time market nearing the $750 price cap at load levels of 42,000 MW and above. During the first two summers of operation, prior to implementation of Deviation Replacement Reserve charges real time prices consistently hit the $250 price cap at very high load levels, but PX prices rarely exceeded $150 due the limited demand in the PX at prices above this level.

VI. Regional Energy Markets

This section examines prices and supply trends in other regional energy markets, which can play a pivotal role in California's energy markets during tight supply and demand conditions.

Imports and Exports

Average imports and exports between the ISO system of surrounding regional markets during peak load hours of June-August 1999 and June 2000 are summarized in Figures 24 and 25. More detailed information is provided in Table 3. As shown in these figures:

- Net imports into the ISO decreased by approximately 1,000 MW during the 51 hours in June with ISO system loads of 40,000 compared to the 56 hours during the summer 1999 months with loads of at least 40,000 MW. As shown in Figure 24 and Table 3, the bulk of this drop in net imports stems from increased exports to southwestern control areas.
- While total net imports of energy and reserve capacity from the Northwest has actually increased, the amount of energy scheduled in the Day Ahead and Hour Ahead market from the Northwest has dropped by over 1,800 MW (see Figure 24 and Table 3). This reflects a significant shift away from the forward markets, toward the Replacement Reserve and real time supplemental energy markets. During tight supply and demand conditions, this shift has created significant uncertainty about the available imports to meet demand in real time and has led the ISO to increase purchases of Replacement Reserves.
- Overall, the combined effect of increased exports to the southwest and decreased scheduling from the northwest energy in the forward markets has been to reduce total net energy imports scheduled in the Hour Ahead market by over 3,000 MW (see Figure 25 and Table 3). As noted above, this has created significant uncertainty about the availability of sufficient supply to meet demand in real time during high load conditions.

Comparison of Regional Energy Market Prices

Regional energy markets in which supply and demand in the ISO system may be transacted include:

- NYMEX futures markets for monthly blocks of energy for peak hours (known as 6x16 blocks).
- The PX block forward market for similar blocks of peak energy
- The PX Day Ahead market for hourly
- Daily spot markets, in which blocks of energy may be bought or sold at the beginning of each operating day, and
- The ISO's hourly real time imbalance energy market.

Prices in the different regional energy markets track closely, particularly when averaged over "6 x 16" peak hour blocks on a monthly basis, as shown in Figure 26. One notable exception to this trend in May and June was NYMEX future prices for monthly energy blocks, which closed significantly lower than prices in the daily spot and hourly PX and ISO energy markets. This may be attributed to the unexpectedly high prices experienced in these months due to the combination of factors examined in this report.

Figure 24. Change in Gross Imports During Peak Load Hours June 1999 vs 2000 (Hours When Loads > 40,000 MW)

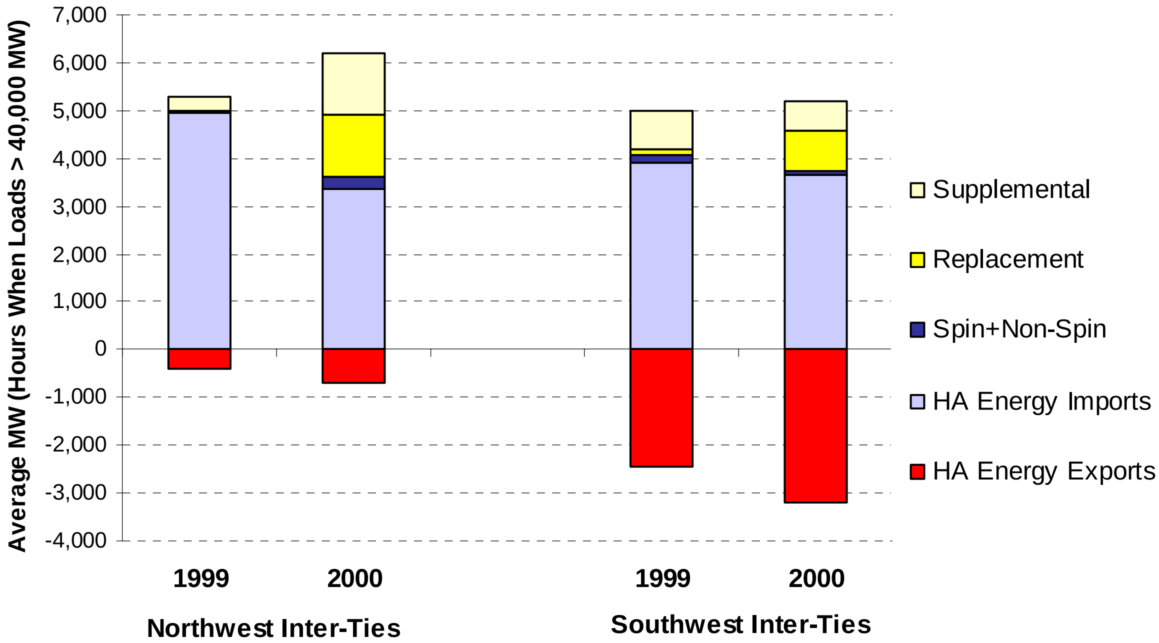


Figure 25. Change in Net Imports During Peak Load Hours June 1999 vs 2000 (Hours When Loads > 40,000 MW)

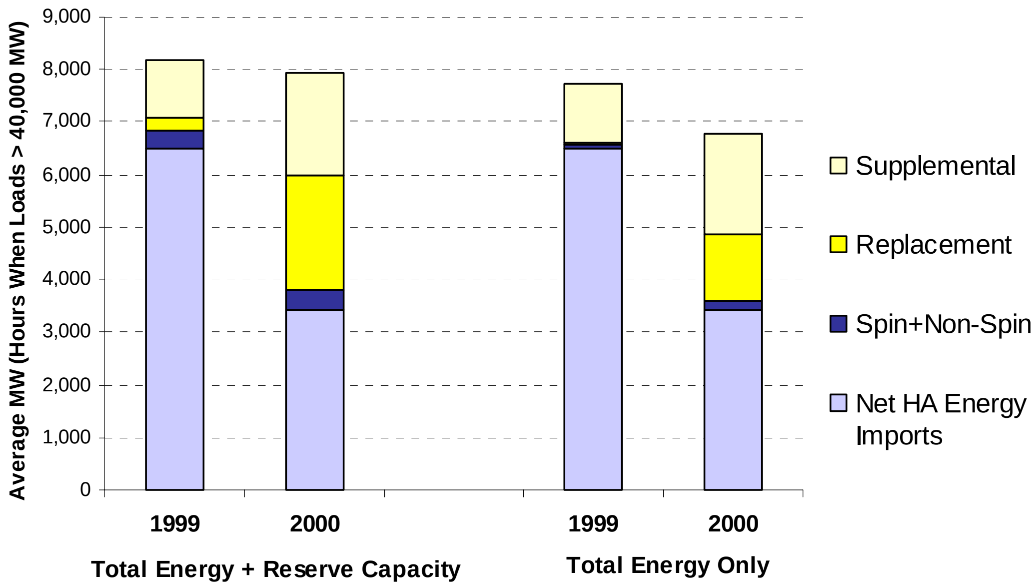


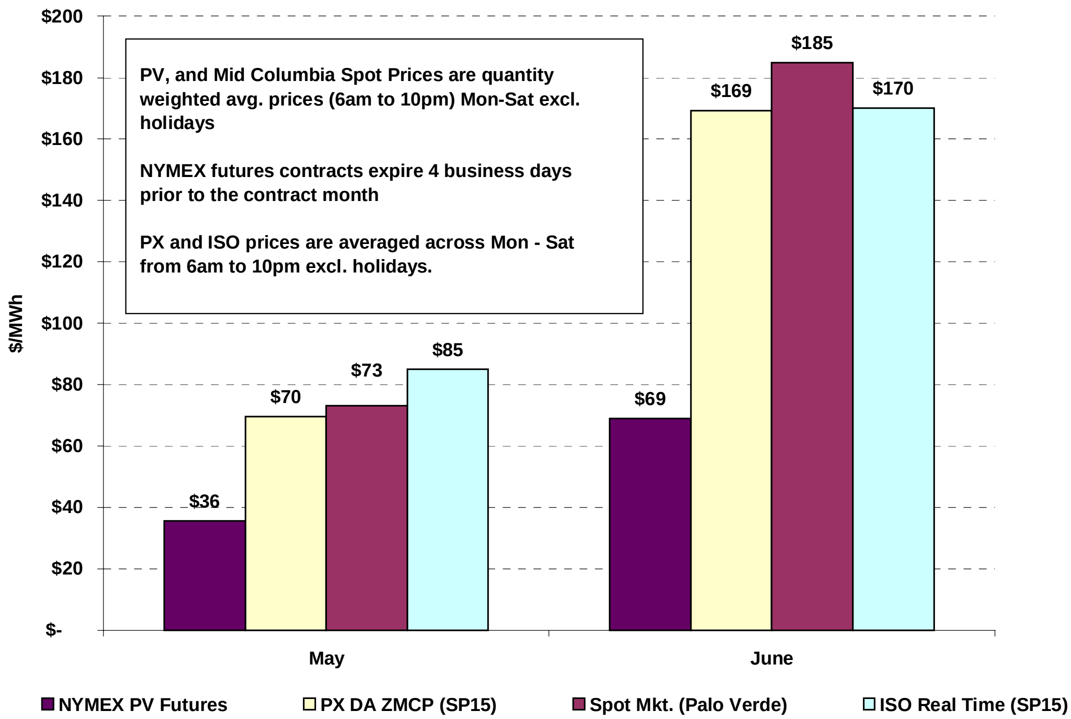
Table 3. Change in Gross and Net Imports – June 1999 vs 2000 During Peak Hours (Loads > 40,000 MW)

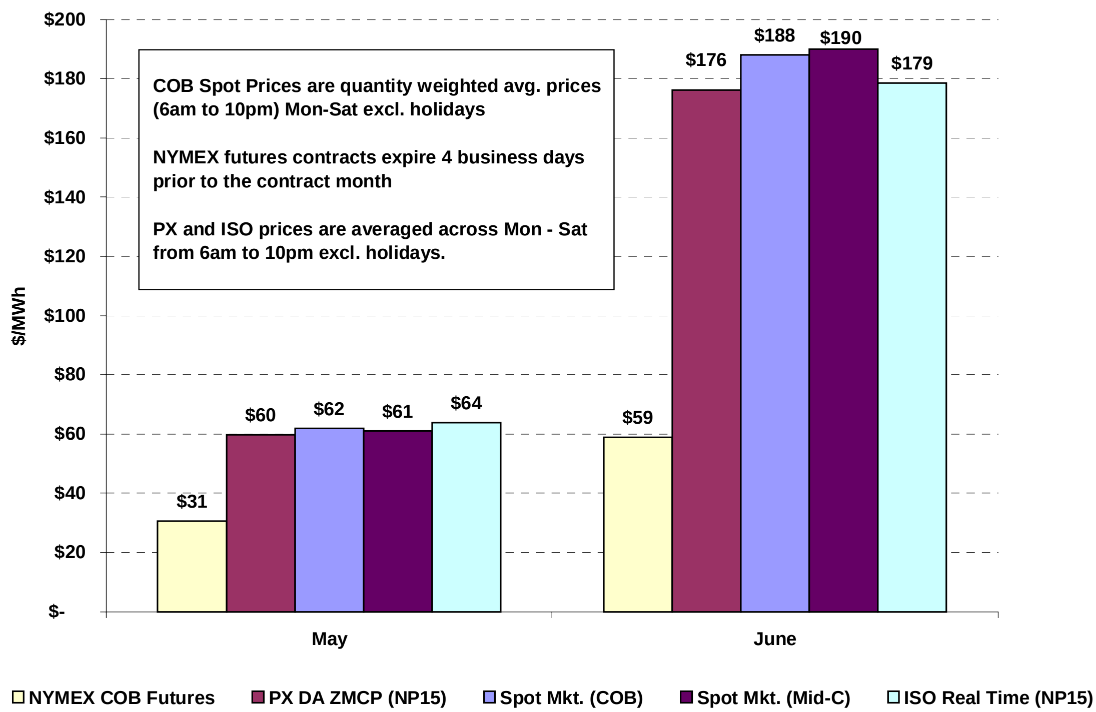
		Hour Ahead Energy Schedules			Oper. Reserves (Spin & Non-spin)		Replacement Reserve					
Region	Year	Imp	Exp	Net	Capacity	Energy	Capacity	Energy	Suppl. Energy	Total HA Capacity	Total Capacity	Total Energy
NW	1999	4,930	408	4,522	21	0	30	1	285	4,573	4,857	4,807
NW	2000	3,348	684	2,663	263	108	1,300	617	1,288	4,227	5,515	4,676
	Change	-1,583	276	-1,859	242	108	1,270	616	1,003	-346	657	-132
SW	1999	3,898	2,439	1,459	191	26	125	31	777	1,776	2,553	2,293
SW	2000	3,638	3,226	412	83	46	861	607	623	1,356	1,978	1,687
	Change	-260	787	-1,048	-108	20	736	576	-154	-420	-575	-606
CA	1999	1,072	289	783	128	29	58	9	57	970	1,027	878
CA	2000	827	193	635	14	9	41	22	33	690	723	699
	Change	-245	-96	-149	-114	-20	-18	12	-23	-280	-304	-179
CFE	1999	0	250	-250	0	0	0	0	0	-250	-250	-250
CFE	2000	3	277	-274	0	0	0	0	1	-274	-274	-274
	Change	3	27	-25	0	0	0	0	1	-25	-24	-24
All	1999	9,900	3,386	6,515	340	55	214	41	1,119	7,069	8,187	7,729
All	2000	7,815	4,380	3,435	361	163	2,202	1,246	1,944	5,998	7,942	6,788
	Change	-2,085	994	-3,079	20	108	1,988	1,205	826	-1,071	-245	-941

Notes:

1. Regions: NW = Northwest, SW=Southwest, CA=Internal California Inter-ties, CFE = Mexico
2. Year 1999 data based on hourly averages for 56 hours between June-August 1999 when total ISO loads > 40,000 MW.
3. Year 2000 data based on hourly averages for 51 hours in June 2000 when total ISO loads > 40,000 MW.

Figure 26. Comparison of Regional Energy Market Prices





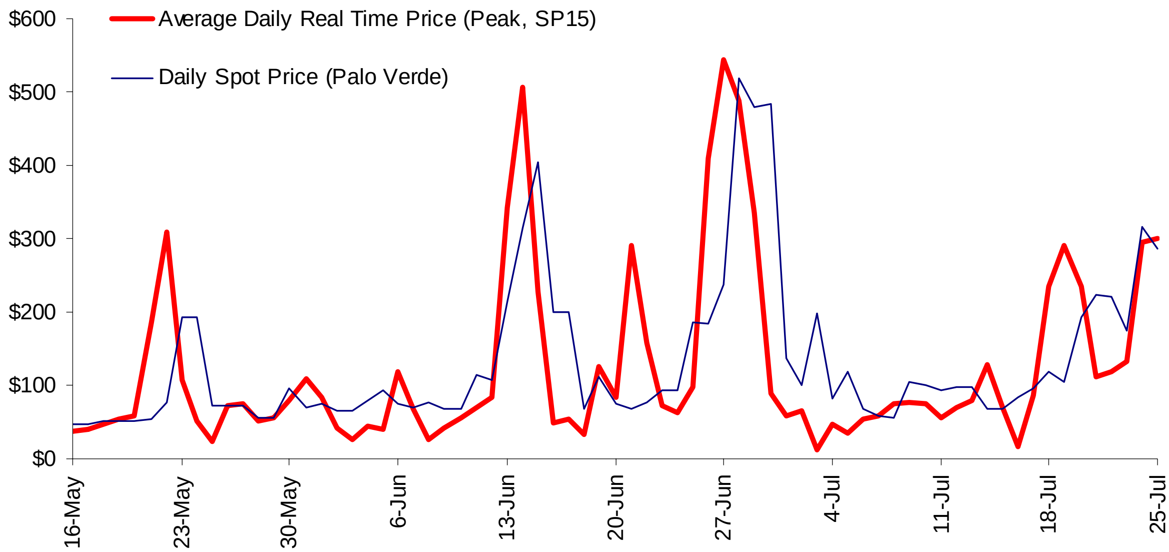
A key question facing the ISO in the context of addressing shortages of scheduled supply and setting the price cap involves the degree to which the ISO's real time market drives or follows other regional supply markets. On one hand, since the ISO's real time market is the final energy market chronologically and is marked by very limited demand elasticity, the real time market may, in effect, set the opportunity cost for both buyers and sellers in other forward markets. Thus, whether prices in the real time market reflect true scarcity or market power, the resulting prices nevertheless represent an opportunity cost that is likely to affect prices in other markets. At the same time, since the ISO's real time market is the final energy market to clear chronologically, during periods of true scarcity most available supplies may be committed through other markets or bilateral transactions unless suppliers expect to receive comparable or higher prices in the real time market. In this manner, real time prices may be driven by other markets during periods of true scarcity of supply.

The remainder of this section provides a brief, preliminary examination of the potential relationship between the ISO real time market and other markets:

- **Spot Market vs Real Time Prices.** First, average real time prices are compared to daily spot market prices to examine the degree to which prices in these markets appear to track, diverge and follow one another. When comparing prices in these two markets, it is important to note that hourly real time prices must be averaged over the 16 hour period used to calculate spot market price indices that are used to report prices in these markets. As shown in Figure 27, prices in these markets track closely, but tend to diverge during high priced periods, with spikes in spot prices lagging behind spikes in the real time market. Prices in the two markets continued to track in a similar manner in July, following the lowering of the ISO's price cap from $750 to $500, with overall prices in both markets lower even during high loads during the week of July 18-25. Together, these trends provide limited indication that spot market prices (for transactions at the beginning of each operating day) may tend to be driven in large part by the previous day real time prices.
- **Impact of Price Cap Decision on Futures Prices.** Futures prices can also be examined to assess whether these prices appear to have been affected by price decisions about the price cap in the ISO real time market. Figure 28 shows a time series of electricity and gas futures prices up to and shortly after the recent Board meetings concerning price caps. As shown in Figure 27, the rise in futures prices from April to early June is closely correlated with gas futures prices, but jumped more sharply following the price spikes in mid June. Futures prices actually rose sharply for several days after the price cap was lowered to $500, before falling in conjunction with gas futures prices just prior the July 6, ISO Board meeting at which price caps were kept at $500. Thus, futures prices also appear to provide a limited and mixed indication of the relationship between these markets.

Figure 27. Comparison of Daily Spot vs Real Time Price

Palo Verde and SP15



COB and NP15

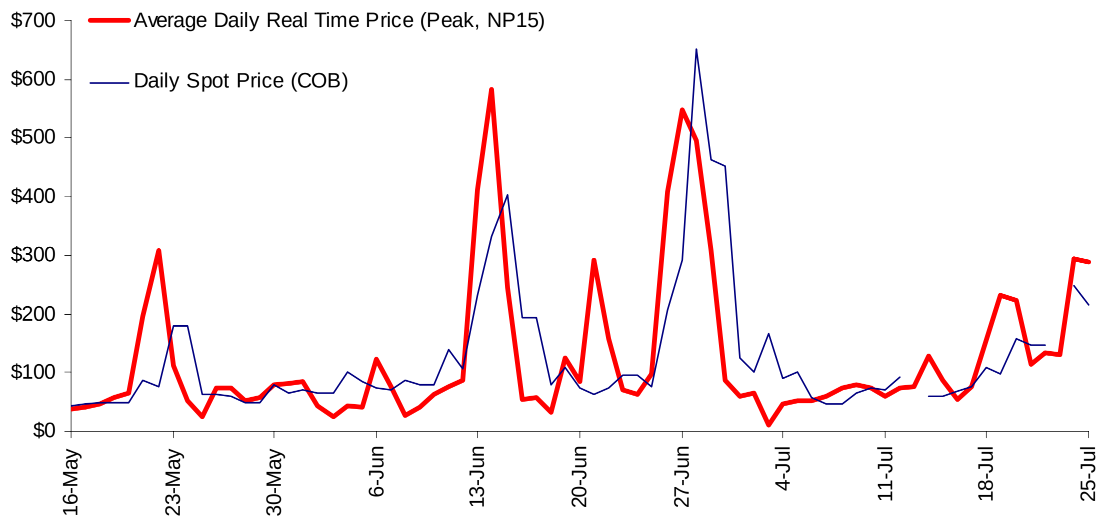
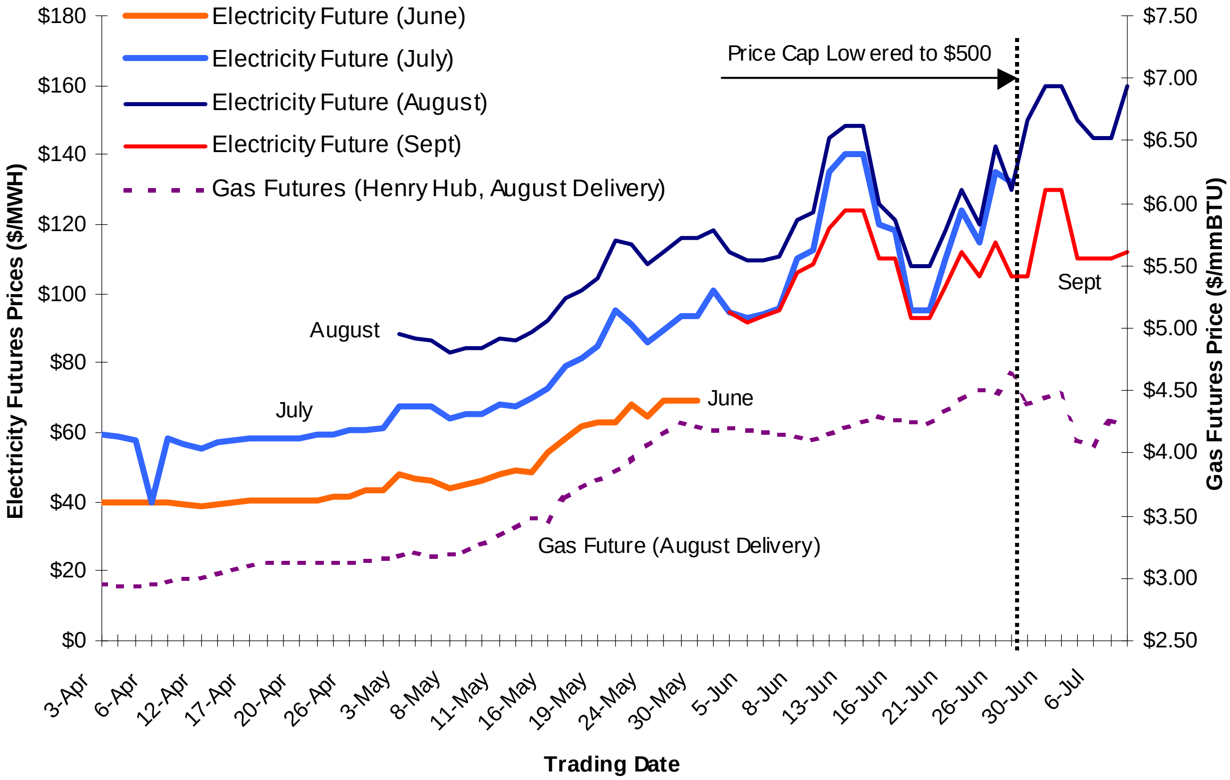
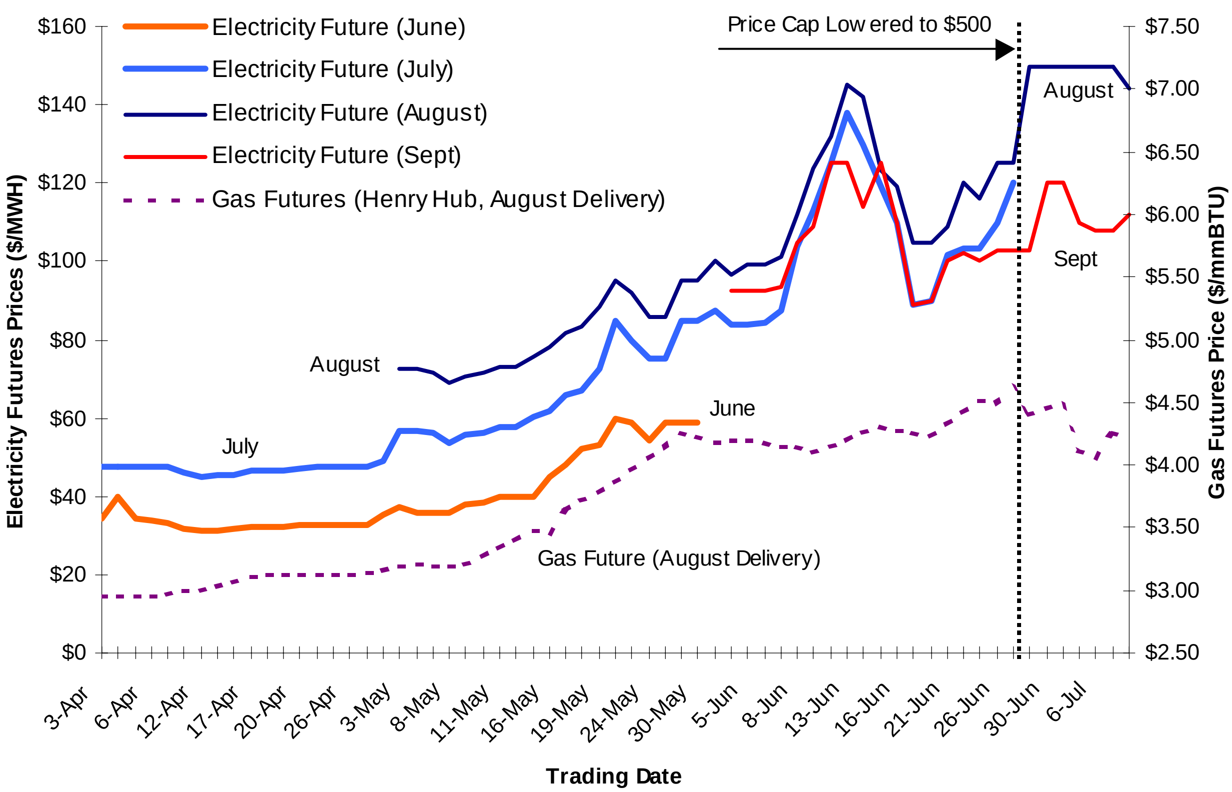


Figure 28. Electricity Future Prices (Palo Verde)



Electricity Future Prices (COB)



VII. Market Power and Supply Scarcity

This section examines the issue of market power vs. supply scarcity in the context of the recent price spikes, as well as the behavior of market participants in causing price spikes. Analysis of supply and demand conditions presented in this section indicate that the persistent price spikes in June and July reflect both the exercise of market power, as well as absolute scarcity of supply during numerous hours.

Available Supply vs. Total System Demand

Figures 29 through 31 compare hourly supply and demand conditions for three periods during May and June when prices spiked in California's markets. Figure 29 provides a discussion of supply and demand conditions during each of these periods. For this analysis, total supply was estimated as follows:

- For the thermal units of non-utility owners, total available supply was based on the maximum operating level of each unit (as indicated in historical metered information) that was in operation and/or bid into the ISO markets. [10]

- For all other units within ISO control area, total supply was calculated for each hour based on total actual generation (including scheduled energy, real time energy dispatched and uninstructed deviations), plus any additional (non-dispatched) capacity bid into the market as Ancillary Services or Supplemental Energy markets. This assumption reflects the fact that most of these units are hydro, QFs or utility-owned generation which is operated and bid into the market during high load hours whenever it is available.

- For imports, available supply was based on final hour ahead schedules (for energy and ancillary service capacity), plus supplemental energy bids and any out-of-market purchases made during periods of peak demand. For imports, both energy and capacity needed to be estimated based on schedules and dispatches, rather than metering data, due to the lag or lack of reliable metering data for many paths at this time.

- The sum of estimated generation from all sources was reconciled with actual system loads as reported by the ISO based on telemeter data in order to account for system losses and any errors due to missing or inaccurate metering data. [11]

Total system demand for energy and capacity was calculated as follows:

- Total realized system demand (as measured by the ISO based on telemeter data) was increased to reflect any load curtailments reported by UDCs.
- Total unmanaged demand for energy was then increased by 10 percent to reflect capacity required for Ancillary Services during peak periods (approximately 3% of upward regulation plus 7% for operating reserve, including spinning and non-spinning reserve).

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[10] If metering information, final energy and ancillary schedules, and supplemental energy bids indicated a unit was available during any hour of a day, it was assumed the unit's full capacity was available for that operating day.

[11] For virtually all peak hours with relatively tight supply and demand conditions, the reconciliation the sum of unit level estimates of generation (plus import schedules) was between approximately 1 to 3% of the ISO official estimate of system loads. This is within the range expected to line losses, in combination with other any errors due to missing or inaccurate metering data

Figure 29. Demand and Supply Conditions (May 20-25)

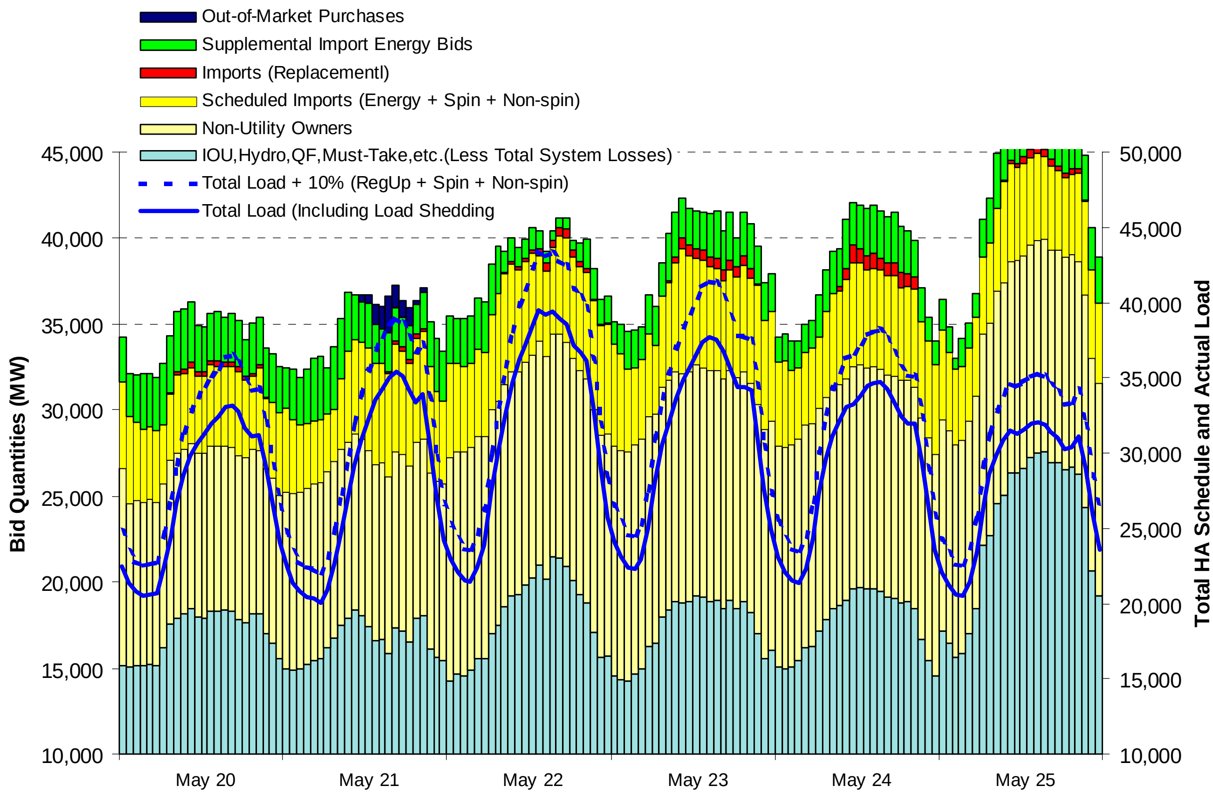


Figure 29 compares total system demand and supply conditions for the period from May 20 to May 25. Total demand is shown in terms of system loads, as well as total system demand for capacity, which is estimated based on total loads plus 10% for ancillary services (Regulation Up, Spinning and Non-Spinning Reserve).

Supply from within the ISO control area is shown for two different categories: major non-utility owners of thermal generation divested by utilities, and all other generation, which includes hydro, QFs, and other utility-owned generation. Supply from major non-utility owned thermal units is based on maximum generating capacity of units available or in operation. Supply from other resources is based on actual generation and capacity scheduled or bid into the ISO's markets. This approach is used to reflect the uncertainty and variability of actual capacity available each hour from hydro units, QFs and many other sources of supply, and the assumption that under peak load conditions the owners of these units have an incentive to schedule or bid all available capacity into the market.

Supply from imports is shown in terms of the following categories. Scheduled imports include energy plus operating reserves (spin and non-spin) scheduled in the Day Ahead and Hour Ahead markets. Import of Replacement Reserve is also shown to highlight the degree to which additional firm generation from other control areas was secured through purchases of large quantities of Deviation Replacement Reserve in June. Finally, we show Supplemental Energy Bids and Out-of-Market purchases from suppliers outside the ISO control area to highlight the critical role these supplies have played in allowing the ISO to meet demand during peak load conditions.

Figures 30 through 33 show similar comparisons of loads and supply during peak load periods in June, when the ISO experienced numerous hours of absolute scarcity of supply.

Figure 30. Demand and Supply Conditions (June 12-16)

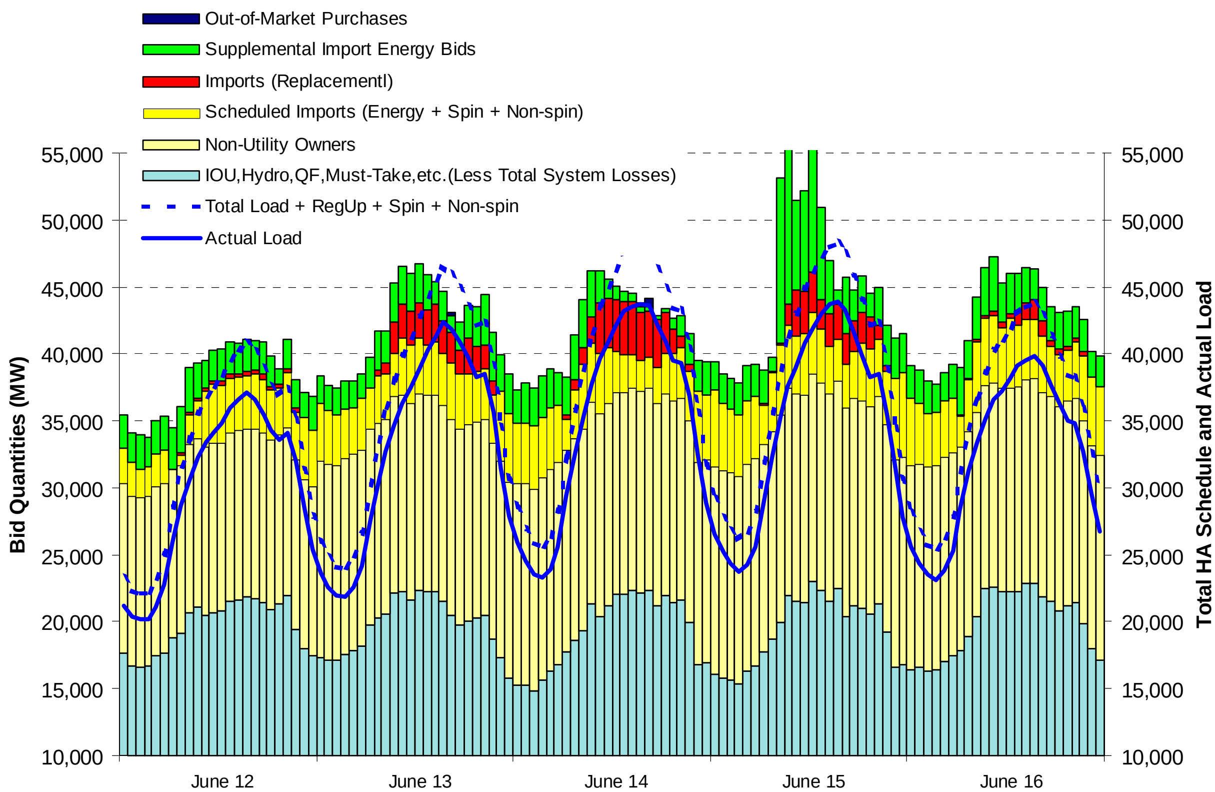


Figure 31. Demand and Supply Conditions (June 26-30)

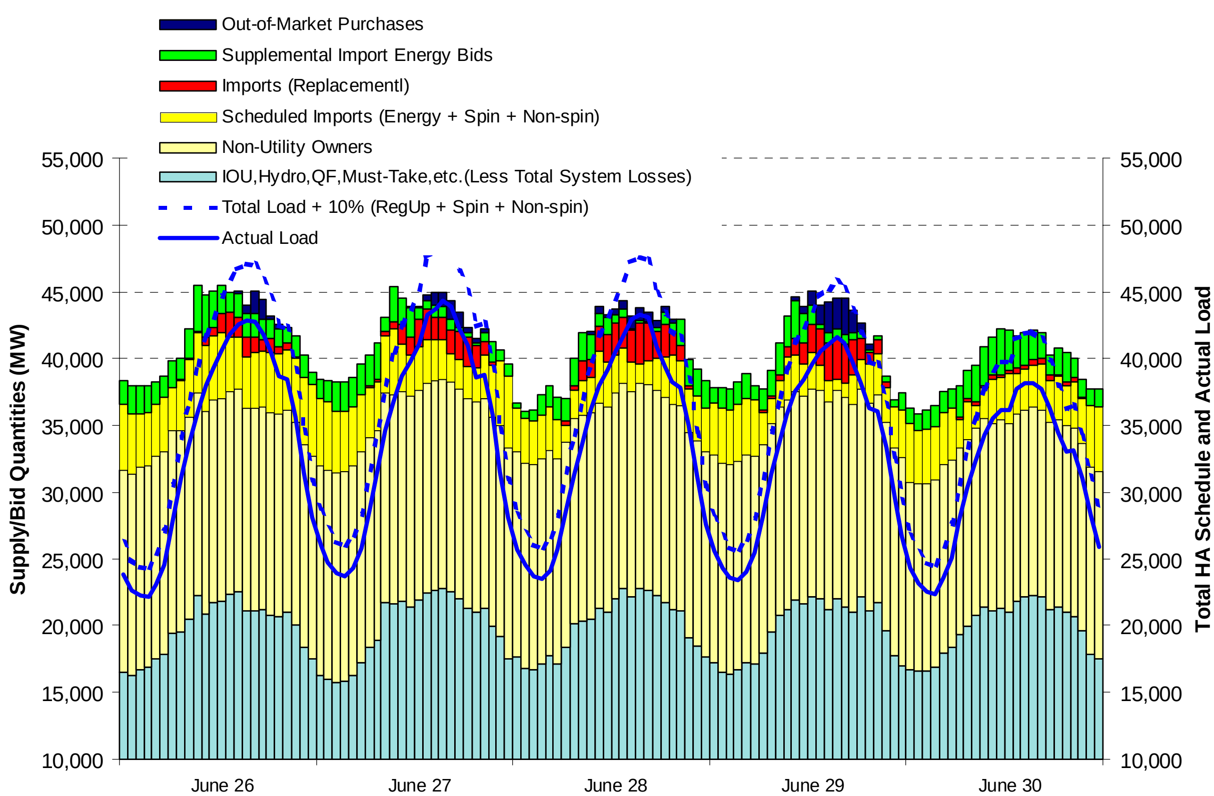
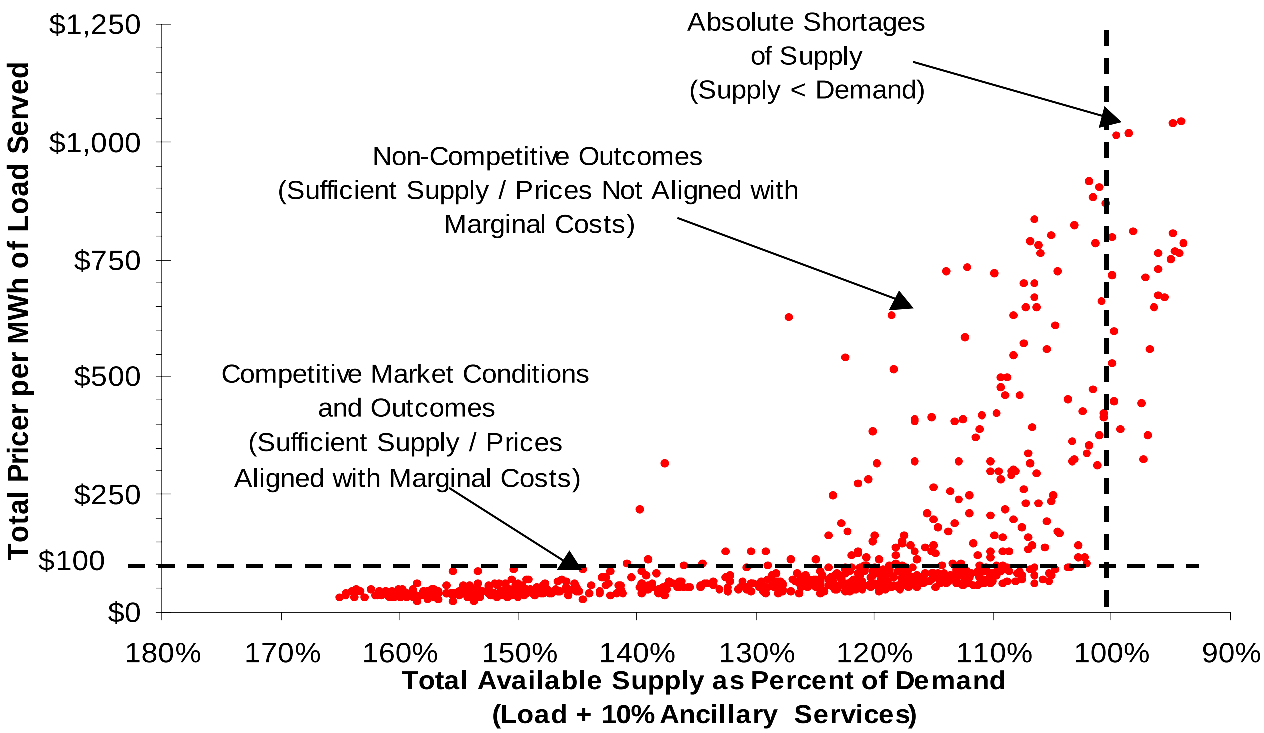


Figure 32. Hourly Demand and Supply Conditions and Total Cost of Load Served (June 2000)



The figure above compares the total price per MWh of load served in the ISO system at different supply and demand conditions, expressed in terms of total available supply as a percent of demand. The total price per MWh of load served is based on the prices and quantities purchased in the different energy and ancillary service markets. Additional details of this analysis were presented in Section II of this report. Total available supply and system demand is based on analysis previously described in this section of the report.

Also shown in Figure 32 are two reference lines that may be used to categorize different market outcomes. Hours to the right of the vertical dotted line represent hours when total available supply was insufficient to meet demand. The horizontal dotted line highlights hours where market outcomes appear to reflect competitive outcomes in which prices are not significantly in excess of the marginal operating cost of the highest cost thermal units within the ISO system. Together, these two lines also highlight market outcomes that are likely to reflect non-competitive market outcomes, or prices significantly in excess of system marginal costs despite sufficient supply.

Table 4 provides a statistical summary of data shown in Figure 32. The Executive Summary of this report and later sections of this report provide additional discussion of the issue of market power vs. scarcity.

Table 4. Summary of Demand and Supply Conditions
And Total Cost of Load Served (June 2000)

Available Supply as Percent of Demand	Number of Hours: Hours	Number of Hours: Pct	Avg. Load (MW)	Avg. Costs $/MWh	Total cost (Millions)	Percent of Total Costs
< 100%	27	4%	42,651	$709	$807	22%
100-110%	106	15%	37,853	$324	$1,335	37%
110-120%	187	26%	33,202	$121	$779	22%
120-130%	134	19%	29,813	$83	$353	10%
>130%	266	37%	23,507	$50	$321	9%
	720				$3,595	

Other Indicators of Market Power

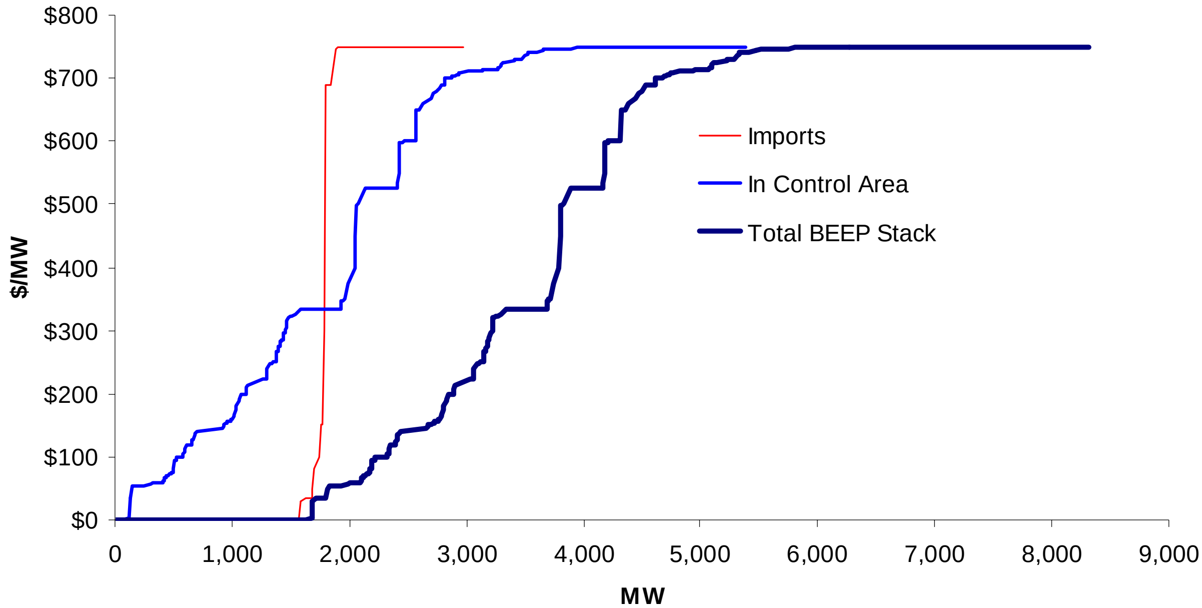
Analysis shown in the previous section indicates that there are many hours of extremely high prices when supply and demand are relatively tight, but there is no apparent shortage of supply. During these hours high prices are most likely the result of market power. The presence of market power can be verified by a high bid price over variable cost by many suppliers in the ISO's markets. The highest variable cost of in-state generators is below $100/MWh, while many suppliers routinely bid a significant part of their capacity at $750 (the price cap level). These bids had to be selected to meet the demand during high load periods.

Figure 33 shows a typical supply bid curve for all sources of real time energy during a peak hour of the June 26-30 price spikes. During these hours, a maximum of about 35,000 MW were scheduled in the Day Ahead and Hour Ahead markets, so that 5,000 MW or more of real time energy was needed to meet demand at load levels of 40,000 and higher.

As shown in Figure 33, observed market power can be the result of combined bidding activity of in-state and out-of-state generators. The available data and tools do not allow detailed analysis of the market power of out-of-state generation owners. The CA ISO, however, is not aware of any acute regional shortages in most of the high price hours (as indicated by reports of either load shedding or inability to maintain minimum operating reserve margins in other control areas in the WSCC). The high price bid by out-of-state suppliers as well as the high prices quoted to ISO's out of market calls are indications of market power of out-of-state suppliers.

The divestiture of generation resources by IOUs has resulted in a market share of approximately 9% for a few of the large non-utility generation companies. These companies are net sellers who can profit from causing price spikes. While for most hours of the market, the CA ISO market is sufficiently competitive, at high load conditions, a capacity share less than 10% can give several suppliers a pivotal position. This implies that at high load conditions, even suppliers with less than 9% market share can have significant market power. When net demand for capacity in the ISO control area is more than 91% of available capacity, suppliers can easily bid high prices, and know their bids will be accepted and set the market clearing price. Thus we have the long duration of prices at the price cap even when there is not a shortage on the system.

Figure 33. Real Time Energy Bid Curve
Typical Peak Hour, June 26-29



Figures 34–36 provide an additional illustration of the exercise of market power under relatively high load conditions.

- As shown in Figure 34, prices in the Replacement Reserve Market hit the $750 price cap virtually every day between the hours of 10 to 22 from June 13 – 15. Each of these days was marked by very similar load conditions, with peak loads in excess of 40,000 MW and a maximum of about 35,000 MW scheduled in the Day Ahead and Hour Ahead markets
- It is important to note that units providing Replacement Reserve still receive the real time energy price in addition to this Replacement Reserve capacity payment when called to provide real time energy. Virtually all Replacement Reserve purchased by the ISO is needed to meet real time demand under high load conditions, so that the direct and indirect opportunity cost of providing Replacement Reserve is likely to be minimal for most suppliers.
- Although price spikes and large quantities of Replacement Reserve purchases on June 13 attracted additional supply into this market, prices continued to clear at $750 on June 14 and 15. As shown in Figures 36 and 37, approximately 1,000 MW of additional supply from imports and an additional 1,000 MW of supply from non-utility owned units in the ISO control area entered the market during this period. However, while additional supply from suppliers outside the ISO control area bid as more aggressive price takers, a significantly higher portion supply offered by non-utility supplies within the control area was bid at or near the $750 price cap.
- Despite the continuation of this bidding pattern, prices dropped on June 16 as loads fell well below 40,00 MW, causing a dramatic decrease in quantity of replacement Reserve purchased by the ISO.

Figure 34. Replacement Reserve Bid Prices
Total Supply in Day Ahead Market (Hours 10-22 Only)

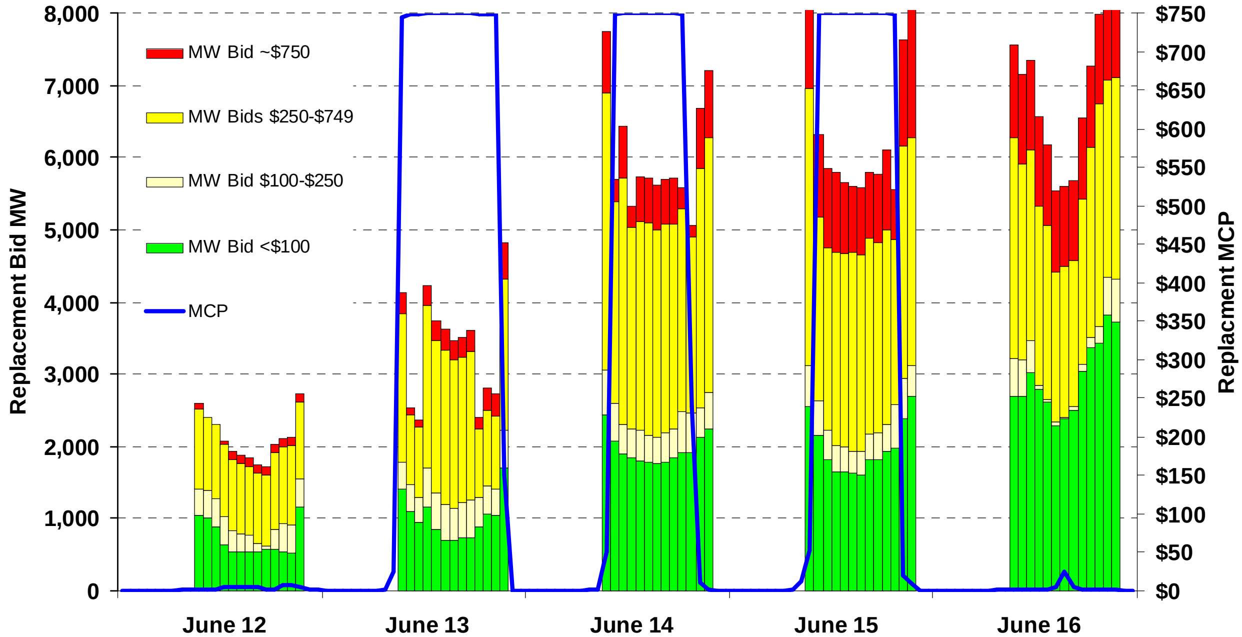
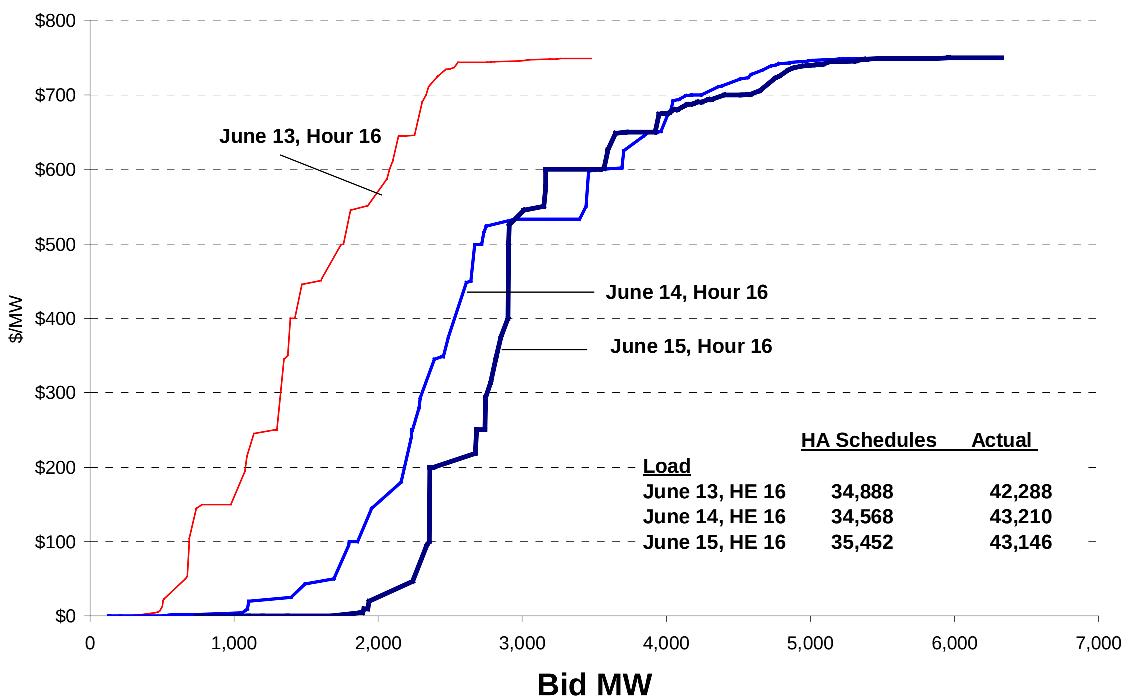


Figure 35. Replacement Reserve Bid Prices
Total Supply in Day Ahead Market



Load	HA Schedules	Actual
June 13, HE 16	34,888	42,288
June 14, HE 16	34,568	43,210
June 15, HE 16	35,452	43,146

Figure 36. Replacement Reserve Bid Prices (Day Ahead Market)
Non-Utility Generation, Within ISO Control Area (Hours 10-22 Only)

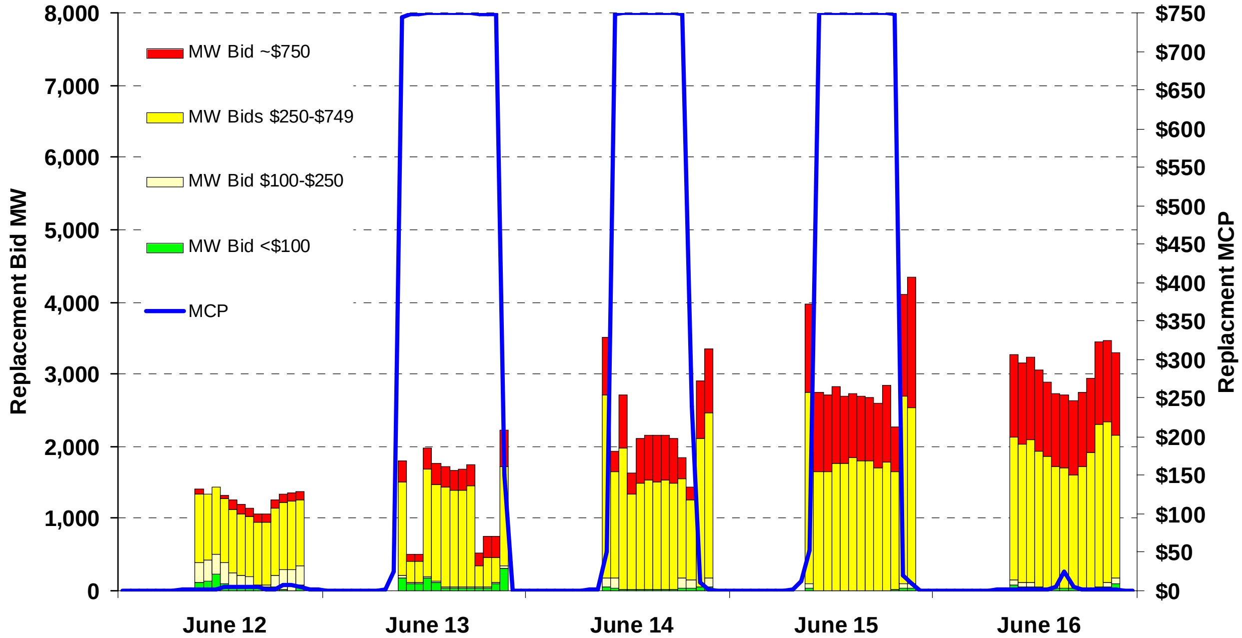
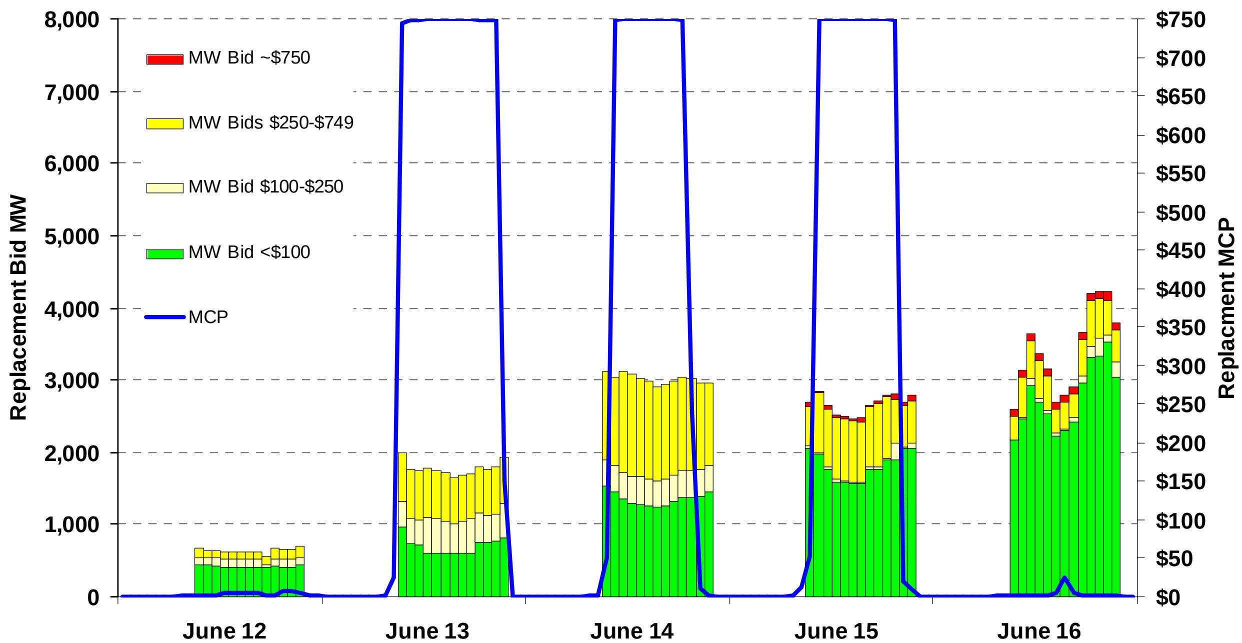


Figure 37. Replacement Reserve Bid Prices (Day Ahead Market)
Imports from Outside ISO Control Area (Hours 10-22 Only)



There are a number of potential mitigation measures that can be implemented to reduce the impact of this exercise of market power. All of the East Coast ISOs have implemented market power mitigation measures to deal with these circumstances. The basic feature of these approaches is to specify conditions under which generators' bids will be re-set to previously agreed upon cost-based levels or average prices during periods which the generator's bids were deemed reasonable. The Department of Market Analysis is exploring the feasibility of implementing these and other market power mitigation options within the California market design.