An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets

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EXECUTIVE SUMMARY

Market Performance

The performance of California's electricity markets continues to be plagued by the market design flaws identified in previous Market Surveillance Committee reports. These uncorrected market design flaws, and market rule changes implemented since the end of the Summer of 1999, have enhanced the ability of market participants to exercise market power in the California electricity market. During the months of May and June of 2000 wholesale revenues from sales of total ISO load (less must-take energy) for all hours of the month in the California energy market were approximately 37% and 182%, respectively, above monthly revenues under perfectly competitive pricing. The June 2000 value of this index of market power is the highest monthly value it has achieved since the start of the California market.

Our analysis also indicates that price caps are of limited effectiveness in constraining market power during high demand periods. In May and June 2000, lowering the price cap from $750 to $250 would have decreased our market power index only by about 20%.

Underlying Causes

For the first eight months of 2000 relative to the same months in 1999, electricity demand in California has grown approximately 5% due to a robust State economy. The failure to construct new transmission and generation capacity within the state to match this demand growth has increased the frequency of periods of generation capacity shortage and the opportunities for generation unit owners to exercise market power in the California electricity markets. Our analysis identifies the following market design flaws that have significantly hindered market performance, the first two of which were identified in previous MSC reports:

- Regulatory constraints on forward contracting for energy and ancillary services by utility distribution companies (UDCs), along with the failure of the UDCs to fully utilize the limited authority they had to enter into forward contracts.

- The lack of a price-responsive final demand because of the limited economic rewards to end users who shift demand from high to low price hours due to the combination of the retail rate freeze and competition transition charge (CTC) recovery mechanism.

- The ISO's policies with respect to the purchase of replacement reserves and the ISO's method for allocating the cost of these purchases

Conclusions and Recommendations

Given the current market design, price caps at $250 for real-time energy and all ancillary services other than Replacement Reserve do not effectively constrain the exercise of market power in the current California market. In fact, monthly average energy prices during June 2000, when the price cap was $750/MWh, were lower than monthly average energy prices during August 2000, when the price cap was $250/MWh. This result occurred despite the fact that virtually the same amount of energy was consumed in California during these two months. Market design changes must be implemented to alter the incentives faced by several classes of market participants. Our recommendations are:

- Remove impediments on UDC forward contracting for energy and ancillary services. The CPUC should remove its position limits on forward contracts. The UDC PX buy-sell requirement also should be eliminated.

- Enact a regulatory structure conducive to robust retail competition. Financially or legally separate the regulated "wires" portion of UDC operations from the unregulated "supply" portion of UDC operations. Set a fixed default provider retail rate and default provider obligation for UDCs. Make the fixed rate is available to all final customers, but allow UDCs and other competitive energy service providers to compete with additional retail rate plans that encourage price-responsive final demand.

- Modify the current ISO replacement reserve policy using a combination the three mechanisms: (1) impose a real-time trading charge, (2) assign the Replacement Reserve penalty for the oversupply of real-time energy, and (3) assign the cost of out-of-market calls to the over-consumption of real-time energy.

- Place greater emphasis at both the ISO Board and staff level on the market-power implications of proposed market rule changes, recognizing that reliability and market power concerns are inextricably linked. Many reliability problems are caused by inappropriate market incentives. From this perspective, re-consider (1) the current out-of-market payment mechanism, (2) the ISO's 10-minute settlement market, and (3) the PG&E hydro divestiture agreement with the ISO.

- Expedite siting and construction of new or expanded transmission and generation capacity in California.

We will address the question of long-term price cap policy in a separate opinion that will be submitted to the ISO Board of Governors in early September 2000.

Introduction

This document is our response to the July 20, 2000 letter sent by Jan Smutny-Jones, the Chairman of the Board of Governors of the California ISO requesting that the Market Surveillance Committee (MSC) provide an analysis of the June 2000 price spikes in the ISO's energy and ancillary services markets. This report identifies several factors that led to the market outcomes that occurred in June 2000. The report contains recommendations for actions that should reduce significantly the risk of future price spikes and improve the efficiency of the ISO's energy and ancillary services markets.

The June 2000 price spikes can be attributed to several factors. The primary cause was the lack of sufficient forward energy and ancillary services purchases for the month of June 2000 by the utility distribution companies (UDCs). This insufficiency of forward purchases of energy and ancillary services is in large part due to restrictions imposed by the California Public Utilities Commission (CPUC) on the extent and manner of forward energy and ancillary services purchases by the UDCs. However, all of the UDCs also failed to take full advantage of the hedging opportunities made available to them by CPUC. This limited forward contracting by the three major load-serving entities in California enhanced the ability of generation unit owners located in and outside of the ISO control area to exercise market power during high-demand conditions. The exercise of market power during high-load conditions because of the lack of a price responsive retail demand is the second factor contributing to these price spikes. The third factor, which further enhanced the ability of generation unit owners to exercise market power, is the ISO's current procedures for allocating replacement reserve costs. In August 1999, the ISO implemented a new approach for allocating replacement reserve costs. The intent of this new approach was to provide a financial incentive for increasing the amount of energy scheduled in forward energy markets. Unfortunately, this design change had a perverse effect, exacerbating under-scheduling as well as the exercise of market power.

We present monthly measures and an overall measure of market performance for the California electricity market for the period October 1, 1999 to June 30, 2000. These measures are compared to values from period June 1998 to September 1999 in order to assess changes in market performance since the first summer of operation of the California market. Our analysis finds that the amount of market power exercised in the California market during October 1999 to January 2000 was significantly higher than the amount exercised in October 1998 to January 1999. February 2000 to April 2000 experienced comparable levels of market power to those that occurred during February 1999 to April 1999. Starting in May 2000, the extent of market power exercised increased dramatically. The index of market power for May 2000 was higher than any monthly value during the summer months of 1999. June of 2000 had, by far, the largest monthly index of market power that has occurred since the start of the California market.

The ISO's flawed replacement reserve policy is one example of a more general problem: market rule changes implemented to enhance system reliability can increase the opportunities for generators to exercise market power. The ISO operators must recognize that they are running markets for energy and ancillary services. For that reason, they must carefully consider the incentives for market participant behavior created by any market rule changes designed to enhance system reliability. Failing to do so can result in unnecessarily high prices in the energy and ancillary services markets and can exacerbate system reliability problems.

To this end, this report describes several market rule changes recently adopted or under consideration to enhance system reliability which have significant potential to increase the amount of market power exercised in the California energy and ancillary services markets. In our view, these rule changes should be carefully reviewed for their market power impacts. They are: (1) changes in the Out-of-Market Payment formula for in-state generators, (2) the proposed agreement between the ISO and PG&E associated with PG&E's proposed divestiture of its hydroelectric assets to an unregulated affiliate, and (3) the ISO's proposed 10-minute settlement mechanism.

Over the past two years, the MSC has provided a number of recommendations for improving the overall competitiveness of California's electricity markets. Many of these recommendations involved changes to both the wholesale and retail sector. The MSC has emphasized on numerous occasions that workable competition at the wholesale level requires fundamental changes to the retail sector. Unfortunately, many of these important recommendations have not been implemented. Had changes in these key areas been implemented prior to this summer, California would have experienced significantly lower average energy and ancillary service prices. This report reiterates many of the fundamental market reforms identified in past MSC reports and encourages the ISO, PX, CPUC, the UDCs, and other interested market participants and state agencies to work together in implementing these changes. Clearly, the construction of new generation and transmission facilities in California will increase the competitiveness of the ISO's energy and ancillary services markets. However, the actual benefits realized by California consumers from these changes in market structure will be significantly less than their potential benefits if the fundamental market reforms we proposed are not addressed.

The California electricity market is not so structurally competitive that market outcomes are invariant to market rules. The industry is composed of a relatively small number of firms, some of which own a sizable fraction of the total electricity generating capacity located in the ISO control area. The geographic distribution of generation unit ownership can allow some owners to exercise locational market power during certain system conditions.[1] In addition, the amount of generating capacity owned by some market participants allows them to exercise market power during high-load conditions, when there is not a physical scarcity of available generating capacity to serve this load.[2] Furthermore, in part because of the retail rate freeze and Competition Transition Charge (CTC) recovery mechanism still in place in the Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) service territories, the hourly demand for wholesale electricity in California is extremely insensitive to price. Consequently, the structure of the California electricity market, at least for the near term, is one where market

[1] Bushnell, James and Wolak, Frank A. "Regulation and the Leverage of Local Market Power in California's Electricity Market," July 1999, (available from http://www.stanford.edu/~wolak.) gives one example of this phenomenon.

[2] Borenstein, Severin, Bushnell, James, and Wolak, Frank A. "Diagnosing Market Power in California's Restructured Electricity Market, August 2000, (available from http:/./www.stanford.edu/~wolak) quantifies the extent of market power exercised in the California energy market during the period June 1998 through September 1999.

outcomes are very sensitive to market rules. This has been a consistent theme of all previous MSC reports. It also underscores the importance of a comprehensive analysis of any proposed market rule change from both a market power and system reliability perspective. We strongly encourage the ISO Board and the CPUC to consider the recommendations summarized in this report and analyzed in detail in previous MSC reports as soon as possible. A market with these design flaws corrected should provide California consumers with all of benefits possible from wholesale competition given the current California market structure.

The remainder of this report describes each of the factors contributing to the June 2000 price spikes and the reasons for the existence of each of these factors. This discussion is followed by a set of short-term and long-term recommendations to improve the efficiency of the ISO's energy and ancillary services markets.

Insufficient Forward Market Hedging

Had California's three utility distribution companies (UDCs) signed forward financial contracts equal to their expected net demand for energy and ancillary services during each hour of the months of May and June of 2000, average prices in the PX and ISO markets during these months would have been significantly lower. Even if the June 2000 price spikes had still occurred, the UDCs would have been largely insulated from this spot market price volatility, because of their forward hedges. Significant purchases of forward financial contracts or forward contracts for delivery of energy from generation unit owners located outside of the ISO control area would have significantly reduced the risk of price spikes in California energy and ancillary services markets during June 2000. The amount of forward contracting with out-of-control-area suppliers necessary to achieve this reduction in the risk of price spikes is substantially less than the net demand for energy and ancillary services by the three UDCs. What is required is that the amount of out-of-control-area energy and capacity be sufficient to eliminate the possibility that there are hours when any market participant located in the ISO control area is pivotal in any of California's energy or ancillary services markets.[3]

There are significant benefits to load-serving entities from purchasing forward financial contracts. First, forward market purchases limit the spot price exposure faced by a load-serving entity. It is subject to spot price risk on its real-time energy requirements only to the extent that they differ from its forward market purchases. The second source of benefits is that forward market purchases from a generation unit owner limits the incentives this supplier has to exercise market power in the spot market. Generation unit owners that have sold forward financial contracts have a strong incentive to bid aggressively (low prices for large quantities of capacity) into the spot market in order to sell a sufficient amount to cover the forward financial commitment with actual physical sales of energy or capacity. The larger the quantity of the forward financial commitment sold by a generation unit owner, the more aggressively this owner will bid into the spot market that the forward financial contract clears against. This is a straightforward application of the basic economic concept of marginal revenue that underlies

[3] A market participant is said to be pivotal in an energy or ancillary services market if the total amount bid (at any price) by all other market participants besides this firm is insufficient to satisfy the market demand.

optimal pricing and bidding behavior.[4] Consequently, UDCs can limit the frequency and magnitude of price spikes in the PX energy markets and the ISO's energy and ancillary services markets by forward purchasing a large quantity energy and capacity. With complete freedom to purchase forward both energy and ancillary services from generation unit owners in or outside the ISO control area, the UDCs could have eliminated or significantly reduced (depending the on quantity of forward energy or capacity purchased) their exposure to spot market price volatility. In addition, these forward purchases of energy and capacity would have induced to the market participants who sold these contracts to bid more aggressively into the ISO's energy and ancillary services market, thereby reducing their incentive to exercise market power during high load conditions.

Unfortunately, until very recently, CPUC regulations prohibited the UDCs from purchasing forward financial contracts outside of the PX block forwards market. On August 3, 2000, the CPUC provided SCE and PG&E with expanded authority to enter into long-term bilateral contracts but restricted trading levels to previously imposed limits on forward contracting. Though this ruling significantly improves UDC hedging options, these trading limits remain unnecessarily restrictive. Until this decision, UDC forward-contracting opportunities were limited to the PX block forwards market, which significantly limited the attractiveness of forward market hedging to the UDCs. The PX block forwards market deals in fixed blocks of hours during the day, which makes it difficult for a UDC to tailor its block forwards purchases to match its daily load shape. The CPUC has also imposed limits on the maximum amount of energy that each UDC can purchase in the PX block forwards market. These quantities are significantly less than the monthly peak net demand for energy by the UDC. For these reasons, as well as several others, none of the UDCs fully utilized their authority to hedge in the PX block forwards market during June 2000. The CPUC restrictions on forward contracting through the PX were especially pernicious because the PX was granted a monopoly over forward trading by the UDCs. We would expect competition among trading venues to lead to the introduction of forward contracts sought by UDCs.

As was emphasized above and discussed in detail in the October 1999 MSC report, these regulatory barriers significantly enhance the ability of generation owners in the California market to raise prices in the PX and ISO energy and ancillary services markets.[5] They also significantly increase the likelihood of price spikes in the California energy and ancillary services markets. This prohibition on where, how, and how much the UDCs can forward contract is a major cause of the high average prices during the month of June 2000. We see little reason to perpetuate the PX monopoly at this point in time, and hope that the CPUC will remove the remaining restrictions on quantities and locations at which UDCs can engage in forward contracting.

A final regulatory restriction that enhances the ability of generation unit owners to raise prices in the PX and ISO markets is the PX buy/sell requirement. In June 2000, the CPUC

[4] Wolak, Frank A. "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market." *International Economic Journal*, 14(2), 1-40 (available from http://www.stanford.edu/~wolak) illustrates an example of this concept applied to electricity markets.

[5] Wolak, Frank A. "Report of Redesign of California Real-Time Energy and Ancillary Services Markets," October 18, 1999. (available from http://www.caiso.com).

authorized UDCs, subject to filing, to trade in other qualified exchanges.[6] However, this decision was overturned by the State Legislature. Requiring a UDC to win in the PX day-ahead auction in order to schedule load and generation on a day-ahead basis severely reduces its ability to limit prices in PX and ISO energy and ancillary services markets. Recall that the ISO only accepts balanced schedules from other Scheduling Coordinators. Generators or loads scheduling through these entities are not required to have their supply or demand bid accepted to schedule on day-ahead basis. As discussed in the October Report, there is a clear benefit to all market participants from a transparent day-ahead financial market for energy. Consequently, if the CPUC or State Legislature feels that a subsidy to the PX is desirable to achieve such transparency, a superior strategy (rather than requiring that all UDC loads and generators bid into the PX day-ahead market) is to require that all UDCs use the PX as their SC. The PX would then need to offer a scheduling service that is distinct from its day-ahead financial market for energy. The PX charges for scheduling only would presumably be lower than their charges for both trading and scheduling. UDCs that have signed long-term forward contracts for energy could schedule them on a day-ahead basis through the PX without having to submit a bid into the PX day-ahead energy market. The PX would still be able to run its day-ahead auction, but it would also offer a day-ahead scheduling service for UDCs that have signed forward contracts with generators located in or outside the ISO control area. This scheme would not only maintain or even increase the volume of energy scheduled through the PX, but it would also allow UDC load and generation the most opportunities to limit high prices in the PX and ISO energy and ancillary service markets through their forward market activities.

Despite the fact that forward contracts reduce exposure to spot market price risk and increase the competitiveness of the associated spot market, as noted above, none of the UDCs purchased PX block forwards contracts up to the limits allowed under the CPUC rules. Under the retail-pricing scheme mandated by the CPUC, San Diego Gas and Electric (SDG&E) has little incentive to purchase energy in the PX block forwards market. The CPUC requires SDG&E to pass-through wholesale electricity prices in the monthly retail electricity bills of its customers. Although the CPUC rules also allow PX block forwards purchases to be passed-through to retail customers, SDG&E's incentives to manage its forward and spot market purchases to minimize wholesale energy and ancillary services costs were greatly muted. Under the retail-pricing scheme mandated by the CPUC, as long as SDG&E purchases its energy and ancillary services requirements from qualifying PX and ISO markets, these wholesale energy and ancillary services costs can be passed-through in retail electricity rates. Assuming the CPUC does not review the prudence of SDG&E's failure to utilize its authority to enter into forward contracts, this scheme for setting retail rates provides greatly diminished incentives for SDG&E to forward contract for energy or ancillary services in order to protect their retail customers from significant wholesale price risk. The wholesale price--whether from the PX block forwards market, the PX day-ahead or day-of market, or ISO real-time market--is simply a cost of doing business that SDG&E is required, under the CPUC rule, to pass-on to consumers. This scheme provides far too little incentive for SDG&E to engage in forward financial contracting to minimize its wholesale energy purchases costs. Consequently, it is not surprising that high wholesale prices occurred in SDG&E territory in June of 2000. There was no large buyer with a

[6] "CPUC Final Opinion Regarding Policies Related to Post-Transition Ratemaking," Decision 00-06-034, June 8, 2000.

strong incentive to purchase energy and ancillary services in the available forward and spot markets at the lowest possible cost.

The other two UDCs have a stronger incentive to forward contract than SDG&E because they are still subject to the retail rate freeze and have outstanding CTC payments to be collected. This fixed retail rate and the opportunity to recover any difference between the fixed retail price and the sum of wholesale energy, transmission and distribution prices in CTC payments, provides very strong incentives for these firms to use their generating capacity and buying clout to limit wholesale energy prices. However, the CPUC mandate that UDCs only forward purchase through the PX block forwards market using the standardized contracts sold in this market subject to maximum quantity restrictions significantly limits the value of forward contracting to these firms. These restrictions prohibited the UDCs from creating mutually beneficial long-term financial contracts with generation units located in and outside the ISO control area that do not fit the one of the standardized forms sold in the PX block forwards market.[7] Because the contractual form offered by the PX may not meet the needs of a seller of electricity outside of the ISO control area, these firms may need to be offered a significant price premium to sell a PX block forwards contract. In addition, a buyer interested in purchasing a forward market hedge for a small number of hours in the day such as from 3 pm to 5 pm, for certain days of weeks, from Wednesday to Friday, during a given month is unable to do so using a PX standard block forwards contract.

The forward contractual forms offered by the PX may also not be the most effective at limiting exposure to spot price risk. For example, one form of forward contract used to limit exposure to price spikes is a one-sided contract for difference (CFD). Under this scheme, the seller agrees to pay the buyer the maximum of zero and the difference between the spot price and some previously agreed upon strike price for each unit of the contract sold. For example, if a generator sold a one-sided CFD for $100/MWh and the spot price turned out to be $250/MWh during that hour, the generator would pay to the purchaser $150/MWh per MWh of the contract purchased. If the price has instead been lower than $100/MWh, the seller would owe the buyer nothing. In this way, one-sided CFDs offer UDCs the opportunity to purchase insurance against price spikes, rather the complete price certainty for a given quantity of electricity sold. Because they are not offered in the PX block forwards market, UDCs do not have the opportunity to purchase this insurance against price spikes. There are a variety forward contract forms that exist in other competitive electricity markets in the U.S. and around the world that limit the buyer's exposure to spot risk and reduce incentives for the seller to exercise market power in the associated spot market. The CPUC restrictions on how, where or how much UDCs can forward contract prevent UDCs from taking advantage of all of the possible forward energy and price spike insurance products which limit their exposure to wholesale price volatility and reduce the incentives generation unit owners have to exercise market power. In addition, the continuing requirement for the UDCs to hedge and schedule their loads and generation on a day-ahead and hour-ahead basis only in the PX markets further limits their access to the full range of potential hedging instruments.

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[7] The standard block forwards contract is for a calendar month of on-peak energy in multiples of 1 or 25 MW. The on-peak time period is defined as the period 6 am to 10 pm, Monday through Saturday (excluding certain holidays). Delivery of the forward contract is to either the NP15 or SP15 congestion zone. There are also super-peak and shoulder peak block forwards products, but these have not been actively traded to date.

Many observers have expressed concern that wholesale electricity prices in California are exceptionally volatile. However, when considered against other markets in the US and around the world based on fossil-fuel generation, these prices are not extremely volatile. In addition, there appears to be an inverse relationship between the level of average prices in a market and the volatility of those prices. For example, Wolak (1999) notes that for 1997 the average price in the England and Wales market was approximately 30 pounds/MWh with a standard deviation of approximate 30.[8] In the Victoria (Australia) electricity market, average prices were 22 AU$/MWh with a standard deviation of 60. It is important to bear in mind that at the time the UK pound was worth more than twice as much as the Australian dollar, so the Australian prices were significantly lower than the England and Wales prices, but they were also significantly more volatile. This relationship between price volatility and average prices can be explained in part by the fact that a major driver of the benefits of forward contracting to both loads and generators is the price certainty that it provides. If prices can be both very low and very high, which was the case in the Victoria market in 1997, there are significant benefits to both sides of the market to signing forward financial contracts. In addition, price volatility also increases the up-front payment a generator will receive for selling a one-sided CFD. Recall that the payoff provided by this contract is max(0,PE-PC), where PE is the relevant spot energy price and PC is the contract strike price. This payoff structure is identical to that for a call option written on the price of a share of stock in a company. Applying standard option-pricing results, this contingent payment scheme is more valuable the higher the volatility in PE. In electricity markets with active forward financial markets, generation unit owners and load-serving entities understand that spot price volatility increases the benefits to forward contracting and that the level of forward contracts can significantly reduce average spot prices. In making their forward contracting decisions, load-serving entities must trade off the benefits of reduced average spot prices against the increased prices that they may need to be pay in forward markets to purchase a sufficient amount of forward energy to cause generators to bid aggressively in the spot energy markets. Generators must bear in mind that signing significant long-term financial forward commitments to supply energy, even at very attractive prices, commits them to be very aggressive suppliers of energy in the spot market, which can reduce average spot prices. This competition between generation and loads in the forward and spot markets and over the terms and conditions of forward financial arrangements is an essential component of a robust and fully competitive wholesale electricity market. Removing all restrictions on UDC forward contracting will allow this essential component of a workably competitive electricity market to develop.

Restrictions on the ability of UDCs to enter into forward financial contracts make very little economic sense, especially for the UDCs still under the retail rate freeze. These restrictions only enhance the ability of generation unit owners located in and outside California to set high prices in the PX and ISO energy and ancillary services markets. They also limit the ability of the UDCs to insulate themselves from price volatility in the PX and ISO markets. These entities should be given wide discretion in their forward contracting practice. UDCs still subject to the retail rate freeze have extremely strong incentives to forward contract in a manner that reduces their wholesale energy purchase costs, because any reduction in wholesale purchase costs should

[8] Wolak, Frank A., (1999) "Market Design and Price Behavior in Restructured Electricity Markets: An International Comparison," in Competition Policy in the Asia Pacific Region, EASE Volume 8, Takatoshi Ito and Anne Krueger (editors) University of Chicago Press, 79-134. (available from http://www.stanford.edu/~wolak).

increase their profits. In addition, because the CTC recovery mechanism is tied to the level of wholesale prices in the PX and ISO markets, these UDCs have even greater incentives to limit the level of wholesale prices through their forward contracting activities. The October 1999 MSC report discusses in detail the incentives faced by all market participants under the combined retail rate freeze and CTC recovery mechanism.

As a short-term solution, we support the general approach taken in the recent bill passed by the Assembly (A.B. 265) which instituted a retail rate freeze for SDG&E customers, while permitting SDG&E to recover reasonable and prudent costs unrecovered through retail bills due to the application of this ceiling. We urge the CPUC also to allow SDG&E broad freedom to engage in forward contracting. The recent CPUC-mandated pass-through of wholesale market purchases in SDG&E retail rates only enhanced the ability of generation unit owners to increase the level and volatility of prices in the PX and ISO markets, even while imposing an extreme financial burden on retail electricity consumers in the SDG&E territory. The new retail rate ceiling should also be accompanied by the requirement that SDG&E offer rate schedules that encourage retail customers to alter their demand in response to hourly wholesale electricity prices. Consumers would have the opportunity to elect to consume according to these pricing plans on a voluntary basis, rather than a mandatory basis as is the case with SDG&E retail pricing plan. Each of these pricing plans, including the retail rate freeze price, would need to be approved by the CPUC for meeting the standard of "just and reasonable" to SDG&E and to its retail customers. By subjecting SDG&E to a fixed retail rates, the CPUC would provide very strong incentives for SDG&E to minimize is wholesale energy and ancillary services purchase costs.

Turning from short-term fixes to long-term solution, we consider here two possible two long-term solutions for creating the sophisticated wholesale demand side with strong incentives to minimize wholesale energy and ancillary services costs necessary for a workably competitive market. One involves completely abandoning retail electricity competition for all but the larger industrial, commercial and governmental customers who are willing and able to fend for themselves in the California electricity market. This scheme would simply continue the proposed short-term solution indefinitely. The CPUC would set fixed retail electricity rates and assign responsibility to the UDCs to make prudent forward and spot energy market purchases subject to the constraint imposed on its revenues by these fixed retail rates. This scheme would protect consumers from high wholesale prices and would provide strong incentives for UDCs to manage their energy acquisition costs, but it would limit the opportunities for the development of price-responsive demand programs. As discussed above, programs to encourage price-responsive retail demand could be put in place. However, all programs would have to be approved by the CPUC. This solution would give up on the hoped-for benefits from retail competition in the area of metering, billing and customer service or other types of product and service differentiation. A single entity setting retail pricing plans subject to CPUC approval could also limit the set of possible mechanisms for final customers and load-serving entities to manage jointly wholesale price risk in a mutually beneficial manner. This solution would also very closely tie the potential benefits available to California consumers from a competitive wholesale market to the ability of the CPUC to set retail rates that allow the UDCs to earn sufficient revenues to remain financially viable.

This solution would also essentially re-institute traditional cost-of-service regulation on the UDCs. However, each UDC now owns little if any generation, and must buy most of its demand from the PX and ISO markets or through bilateral contracts. This solution would continue to leave unanswered the fundamental question of cost-of-service regulation: What is the regulated firm's minimum cost mode of production and how should output prices be set to provide the strongest possible incentives for the firm to produce in this manner? Setting regulated retail rates in this environment would most likely be even more difficult for the CPUC than under the former vertically integrated monopoly regime. Under this market structure, the CPUC would have to determine the prudency of the energy purchasing decisions made by UDCs across the many energy and capacity markets and purchasing time horizons available. A perceived inability of regulatory processes around the world to cause firms to produce in a least-cost manner in the former vertically integrated monopoly regime led to the widespread introduction of competition in generation and supply. It is difficult to see how regulating the UDCs' retail rates under the current regime will be less complex than regulating them under the former vertically integrated monopoly regime when the UDCs owned significantly more generation and also operated the bulk transmission grid in their service territories.

A second approach, which we favor, is outlined in detail in the October Report. It suggests a plan for setting the default provider rate and separating the distribution or "wires" side of the UDC's business from the electricity retailing or "supply" side of the business. The "wires" side of the business would continue to be regulated by the CPUC. A regulated price for delivering electricity from the bulk transmission grid to any location in the UDC's service territory would be set by the CPUC. This price would be paid by all energy service providers (ESPs) delivering electricity to final customers in that geographic area, including the "supply" side of the UDC.[9] The supply side of the UDC's business would be unregulated, except for the requirement that it offer a fixed default provider retail rate for each customer class that can be selected by any customer at any time. As discussed in the October Report the existence of this default provider rate does not prohibit the supply affiliate of the UDC from offering consumers other rate schedules that both consumers and the UDC find mutually beneficial. The October Report also provides several recommendations for assigning revenue cycle services obligations to the UDCs versus the competitive energy suppliers. This scheme of separating the regulated "wires" side of the UDCs' business from the competitive supply side of the business was recently put in place in the England and Wales electricity market. This scheme can be immediately implemented for customers in the SDG&E service territory, once a fixed default provider rate has been established and the revenue cycle services obligations have been determined.

A major advantage of this approach is that it does not require the CPUC to make a determination of the prudency of the wholesale energy purchasing decisions of the UDC. The supply side of the UDC's business can forward contract or purchase on any of the PX and ISO markets in any manner they find profitable. Because all ESPs, including the supply side of the UDC, must purchase local distribution services from the wires side of the UDC at a rate set by the CPUC, competition among ESPs to attract customers will provide strong incentives for the provision of the full array of retail pricing plans that are mutually beneficial to consumers and

[9] This is analogous to the provisions in the telecommunications industry requiring incumbent local exchange carriers to offer unbundled network elements to competitive local exchange carriers at regulated rates.

ESPs. The obligation of the supply side of the UDC to supply energy at the default provider rate will protect all consumers from the risk of wholesale price volatility and provide strong incentives for the UDC to forward contract to hedge the wholesale price risk associated with supplying energy at the default provider rate. Under this solution, only those consumers that elect to take on wholesale price risk in exchange for the expectation of a lower annual average retail rate than the default provider rate will be exposed to retail price volatility.

Because of the competitive advantages afforded to UDCs selling retail electricity under the rate freeze and CTC recovery period described in Section 7 of the October Report, changes in the CTC recovery mechanism must be implemented before this scheme can be put in place for the SCE and PG&E. One change would be to convert the CTC recovery mechanism to a fixed per MWh charge that must be paid by all customers located in the UDC's geographic territory for the remainder of the CTC recovery period or until the UDC fully recovers its outstanding CTC payments, whichever occurs first. This change would eliminate a major source of the competitive advantage enjoyed by the incumbent UDC under the current combined retail rate freeze and CTC recovery mechanism. Because this fixed per MWh charge does not vary with monthly wholesale energy purchase costs, ESPs with lower wholesale energy purchase costs than the UDCs can used these cost savings to earn either higher profits or to set lower retail prices in order to attract customers away from the UDCs.

Market Power in the California Electricity Market

There is ample evidence (see below) of the existence of market power in the California electricity market. However, this market power primarily exists during high-demand conditions, which tend to occur in the months of July to September. Happily enough, during the first two years of operation of the ISO, market outcomes were on average very close to the perfectly competitive ideal for the remaining nine months of the year, October through June.[10]

Many observers will be interested in whether the level of market power exercised in the California market is higher than the amount exercised in other markets in the U.S. and around the world. Unfortunately, a rigorous answer to this question for the other U.S. ISOs is not yet possible; due to confidentiality restrictions, the data necessary to perform these analyses are not currently available. Nevertheless, informal analyses based on the best available data suggests that the extent of market power exercised in the California market prior to June 2000 has not been significantly different from the level exercised in any of the other US ISOs. One can even build a case that, at least prior to recent price spikes in June 2000, the California market experienced the lowest level of market power among the U.S. ISOs.

Ultimately, we are concerned about market power exerted by generators serving California electricity consumers. The extent of market power enjoyed by a generation unit owner is governed by four general factors: (1) the market-wide elasticity of demand for electricity during the time period in question; (2) the aggressiveness of bidding by other

[10] See Table 4 of Borenstein, Severin, Bushnell, James, and Wolak, Frank A. "Diagnosing Market Power in California's Restructured Electricity Market, August 2000, (available from http:/./www.stanford.edu/~wolak).

generation unit owners, which is influenced by forward-contract positions and the extent of aggregate excess capacity during the time period in question; (3) the individual generation unit owner's share of available capacity to serve load; and (4) the various rules and regulations in place. Taking as given the structure of ownership of generation capacity in the short and medium term, we focus here first on the market-wide elasticity of demand.

Market power in the California electricity market is caused in large part by the combination of two factors: a final demand that is not responsive to hourly wholesale price movements, along with the fact that a relatively small number of market participants control significant portions of the available generating capacity. The October Report described in detail the lack of incentives for price-responsive final demand caused by the current CTC recovery mechanism and retail rate freeze. It is important to emphasize, in the light of the recommendations made in the previous section, that it is not the retail rate freeze alone that destroys the incentives for price-responsive final demand, but its combination with the CTC recovery mechanism. As noted in the October Report, monthly CTC collections are equal to the difference between retail revenues and the sum of wholesale energy and ancillary services costs, transmission and distribution costs, and other regulatory costs. This definition of CTC collections provides limited incentives for retail customers still subject to the retail rate freeze to reduce their demand in response to high wholesale prices. Any reduction in wholesale energy and ancillary services prices that result from the price-responsiveness will be met with higher monthly CTC charges, thus leaving their total monthly electricity bill virtually unchanged. The October Report discusses this mechanism and the resulting incentives it creates in detail.

Although price spikes can indicate the exercise of market power, we should emphasize that the risk of price spikes, regardless of their cause, also provide incentives for final consumers to make the investments necessary to be able to change their demand in response to hourly wholesale prices. As discussed in the October Report, the value of any investment is the risk-adjusted, discounted present value of future benefits flowing from that investment. Real-time meters or electricity storage technologies that allow consumers to shift their demand within the day and across days in response to wholesale prices require up-front investments. Unless consumers anticipate benefits in the form of reduced future energy bills, these investments will not take place. The benefits from these investments come in the form of avoiding consumption during high-priced periods. Consequently, the higher are prices during these periods, the greater are the returns consumers will reap from these investments, and the more likely are these investments to occur. Consequently, a major driver of the amount of price-responsiveness in final demand is the risk and magnitude of potential price spikes in wholesale markets.

The logic of the previous paragraph does not argue for price spikes simply to encourage price-responsive hourly retail demand. Nor does it argue that market power is necessary to encourage a price-responsive hourly retail demand. It does, however, show that the price spikes associated with the exercise of market power provide strong incentives for defensive responses from final consumers that will (eventually) tend to erode the market power and reduce the extent of future price spikes. Price spikes provide the economic signals for retail consumers to make the investments necessary to shift their demand in response to high prices. (Indeed, temporary price increases that merely reflect scarcity send efficient signals for consumers to make investments to reduce demand during peak periods.) The increased ability of retail customers to shift their demand across hours of the day yields a more price-responsive wholesale demand, which limits the ability and incentives generation unit owners have to exercise market power. This reduced ability and incentive to exercise market power ultimately leads to lower average wholesale prices. Consistent with the discussion of the previous section, high prices also encourage forward contracting, which further limits the ability of generators to exercise market power in the spot market. In both cases, without some risk of high spot prices during peak periods, final consumers will have little incentive to make the investments necessary to be price-responsive and load-serving entities will likewise have little incentive to enter into forward financial arrangements.

A major concern arising from the events of June 2000 is that several market participants possess significant market power and that this market power should be mitigated. Should the ISO Board or Management decide to file with FERC a plan for more extensive measures beyond purchase price caps to mitigate market power possessed by generation owners in the larger California market, this plan should operate by altering the incentives faced by generators, not by imposing rigid rules on the behavior of bidders. Market power mitigation measures that place restrictions on generator behavior without altering the their incentives may simply result in the exercise of the same or greater amount of market power, but in a different manner. Behavioral rules merely eliminate one easily observable symptom of market power—price spikes. However, they may not eliminate the incentive of a firm to raise market prices through bidding strategies that nominally honor behavioral rules imposed by regulators. Consequently, even if the frequency and magnitude of price spikes has been reduced, market participants may be able to exercise similar or greater levels market power on an annual basis.

A superior strategy for dealing with these market power concerns is to correct the major market design flaws that currently exist which enhance the ability of generators to exercise their market power. At the same time, the ISO, CPUC and relevant State agencies should work together to develop regulatory reforms that speed the siting and approval process for transmission expansion and new generation. As noted above, eliminating restrictions on UDC forward financial contracting can significantly limit the ability of generators to exercise market power. The market power results for the off-peak months of the California electricity market referred to above suggest that there are opportunities for gains from trade between the UDCs seeking greater price certainty during the peak demand months and generators seeking greater price certainty during the off-peak months. A forward financial contract that provides a generation unit owner with a slightly higher (than the average spot price) contract price in all hours during the off-peak months in exchange for a significantly lower (than the average price spot) contract price in the smaller number off-peak month hours should be acceptable to both the UDCs and generators. These sorts of intertemporal gains from trade can be exploited if the UDCs are allowed broad freedom in forward contracting. Evidence that such intertemporal gains from trade are acceptable to the generation unit owners in California is Duke Energy's recent announcement of an offer to sell a five-year forward contract for energy at $50/MWh.

Natural gas prices also must be considered when attempting to infer the extent of market power exercised from the movement over time of prices in the PX and ISO markets. Over the past year, the price of natural gas has almost doubled, from slightly less than $2.50/MBTU to approximately $5.00/MBTU. This implies that a 10,000 BTU/KWh facility which had a marginal operating cost in the neighborhood of $25/MWh during June and July of 1999 now has a marginal operating cost of close to $50/MWh. Consequently, any price comparison between the Summers of 1999 and 2000 must account for the significantly higher natural gas prices during the Summer of 2000. The market power analysis reported in Borenstein, Bushnell and Wolak (BBW, 2000) accounts for these costs differences in making market power measurements.[11] Table 1 below updates Table 4 from BWW (2000) for the period October 1999 to June 2000. Each entry in the table is the monthly value of the index of market power, MP(S), from BBW (2000) for the period June 1998 to June 2000. The BBW market power index measures, on a monthly basis, the extent to which actual wholesale revenues exceed those that would occur under a perfectly competitive market outcome. MP(S) normalizes these excess revenues by the value of actual revenues. To facilitate comparison across years, the monthly values of MP(S) for each year from 1998 to 2000 are reported in separate columns. As noted in BBW (2000), the Summer 1998 experienced the exercise of considerably more market power that did the Summer of 1999. This is borne out by the considerably larger monthly values of MP(S) in the months of July to September of 1998 relative to the same month in 1999. The latter part of 1999 showed considerably more market power than latter part of 1998. The values of MP(S) were significantly higher in October to December of 1999 versus the same months in 1998. This trend continued into January and February of 2000 versus the same months in 1999. March and April of 2000 shows less market power than did April and May of 1999. However, in May and June of 2000 this trend dramatically reversed. The extent of market power exercised in the California energy market in June of 2000 was the largest it has been since the market began operation. The actual monthly revenues from purchasing total ISO load minus must-take generation for June 2000 minus the predicted cost of purchasing this same amount of energy under the perfectly competitive benchmark was 64.6% of the actual cost of purchasing total ISO load less must-take generation for June 2000.

The ISO's real-time energy market had a price cap of $750/MWh beginning on October 1, 1999. Before that date the price cap was $250/MWh. In order to assess the impact of this higher price cap on our measure of market power, the measure of market power is re-computed under the following assumption: For each hour that the unconstrained PX price exceeded $250/MWh, the actual price entering into MP(S) was reset to $250/MWh. The monthly values of MP(S) were re-computed under this assumption. The values for October 1999 to May 2000 were identical to the ones computed using the actual unconstrained PX price. The last column of Table 1 reports these modified monthly indexes of market power for first six months of 2000. The values of MP(S) computed implementing a $250/MWh cap as described above for May and June 2000 led to somewhat smaller values. However, the value of MP(S) in June 2000 computed under this assumption is still the largest monthly value of MP(S) besides the value for June 2000 computed using the actual unconstrained PX prices reported in the third column of Table 1.

Although we do not yet have the ISO settlement data necessary to compute our indexes of market power for the months of July and August of 2000, it is unlikely that a lower price cap during most of this two-month period reduced the extent of market power exercised. Monthly average energy prices during June 2000, when the price cap was $750/MWh, were lower than monthly average energy prices during August 2000, when the price cap was $250/MWh. This

[11] Borenstein, Severin, Bushnell, James, and Wolak, Frank A. "Diagnosing Market Power in California's Restructured Electricity Market, August 2000, (available from http:/./www.stanford.edu/~wolak).

result occurred despite the fact that virtually the same amount of energy was consumed in California during these two months.

The value of MP(S) computed over the entire period October 1999 to June 2000 was equal to 0.363, meaning that actual revenues minus the competitive benchmark revenues for non-must-take energy over this time period was 36.3% of actual revenues for non-must-take energy over this time period. The overall value of MP(S) computed over this same period assuming the $250/MWh cap was imposed as described above yielded a value of 0.275. This is still a very substantial increase in revenues for non-must-take generation over this time period.

The indexes reported in Table 1 can also expressed as the percentage increase in monthly wholesale energy revenues relative to monthly wholesale energy revenues under the perfectly competitive benchmark. Let TR(actual) equal actual monthly wholesale revenues from the sale of total ISO load less must take energy for all hours during the month. Let TR(benchmark) equal the monthly cost of purchasing this same quantity of energy assuming perfectly competitive pricing of energy. The monthly index of market power reported in Table 1, MP(S) for month S, is equal to (TR(actual) – TR(benchmark))/TR(actual). We can express this revenue difference to the exercise of market power as a fraction of TR(benchmark) as function of MP(S). This calculation yields: (TR(actual) – TR(benchmark))/TR(benchmark) = (1/(1- MP(S))) – 1. Applying this equal to the numbers for May and June of 2000 given in Table 1, the increase in monthly wholesale revenues due to departures from competitive pricing is equal to 37% and 182%, respectively, of the predicted revenues under perfectly competitive pricing.

In summary, for the period October 1, 1999 to June 30, 2000, the BBW (2000) index of market power shows the exercise of a significant amount of market power in the California energy market. This exercise of market power was somewhat high during the latter part of 1999, but it reached the highest levels that have existed in the California energy market during June of 2000.

TABLE 1

Monthly Indexes of Market Power for June 1998 to June 2000 MP(S) Index from BBW (2000)				**Modified Monthly MP(S) Assuming $250 Price Cap**
Month	**1998**	**1999**	**2000**	**2000**
January	-	-0.021	0.174	0.174
February	-	-0.061	0.077	0.077
March	-	-0.063	-0.007	-0.007
April	-	0.040	-0.103	-0.103
May	-	0.007	0.268	0.218
June	-0.593	0.071	0.646	0.506
July	0.280	0.171	-	-
August	0.399	0.070	-	-
September	0.350	0.154	-	-
October	0.073	0.338	-	-
November	0.003	0.292	-	-
December	0.117	0.128	-	-

Although prices spikes often indicate the presence of significant market power, as discussed in BBW (2000), the proper measure of the amount of market power exercised in the wholesale electricity industry is the extent to which market prices are in excess of the competitive market ideal.[12] Measuring market power based solely on transitory price spikes may be misleading, both because of the market efficiency benefits of price spikes described above, and because some temporary price increases can be expected during periods of peak demand even in perfectly competitive markets. Therefore, looking over a monthly or annual basis is likely to be more informative.

Price spikes send very strong economic signals for loads to reduce their consumption during these time periods. The major failure of the electricity restructuring around the world and in the U.S. is the lack of a sophisticated and active demand side of the wholesale electricity market. Any market with extremely inelastic demand is particularly susceptible to the exercise of market power, especially during periods in which a large fraction of available capacity is required to serve that demand. During such system conditions in electricity markets, the only market participants disciplining the exercise of market power are loads that are willing to shift some or all of their consumption away from periods with high wholesale prices. A study of large industrial customers in the England and Wales market purchasing electricity according to the half-hourly wholesale Pool price found economically significant price-responsive electricity demand across a wide array of industries.[13]

Because price-responsive consumers choose not to consume rather than to pay high prices, the existence of a substantial volume of price-responsive final demand can allow the electricity market to continue to serve the same number of consumers with a smaller amount of total generating capacity. For example, rather than construct and operate 500 MW of capacity to serve a peak demand that only occurs twenty hours per year, it may be far more economical to allow wholesale prices to rise during those twenty hours and trigger sufficient demand reduction to make unnecessary the construction of the additional 500 MW of capacity. Note that the total amount of energy consumed on an annual basis is not necessarily reduced as a result of allowing high prices to shave demand peaks rather than constructing new generation capacity: that demand may simply shift to the lower-priced periods.

With a price-responsive demand, total capacity costs to the industry can be significantly lower than would occur under a regime without a price-responsive demand. This is the basic principle behind peak-load pricing, which was originally developed for use in the electricity industry and has been well understood for over 75 years. Assuming the same amount of energy is consumed on an annual basis under both regimes, significantly lower annual average wholesale prices should occur under a regime with a significant amount of price-responsive demand. By allowing price spikes to shave demand peaks, there is no need to construct and pay for the additional generating capacity to serve the demand peaks that would occur without the price spikes. A final demand that reduces its consumption in response to high prices also faces

[12] As discussed in detail in BBW (2000), the competitive market ideal hourly price during periods without a physical scarcity of available generating capacity is equal to marginal cost of the highest cost unit operating. BBW (2000) also characterizes the competitive market price during periods of physical scarcity of available generating capacity.
[13] Patrick, Robert and Wolak, Frank A. "Estimating the Customer-Level Demand for Electricity under Real-Time Market Prices," August 1997, http://www.stanford.edu/~wolak.

all generation unit owners attempting to raise energy and ancillary services prices with an increased prospect of reduced sales. This more elastic wholesale demand leads to more aggressive bidding by generation unit owners into the PX and ISO markets, which results in lower average wholesale energy and ancillary services prices.

Evidence that this is not simply a theoretical possibility comes from the experience with airline deregulation in the US. During 1977, the last year of regulation of the U.S. domestic airline industry, the average load factor (total seats filled divided by total seats flown) was approximately 55 percent. In contrast, during 1999, the average load factor for the US domestic airline industry was approximately 73 percent. This tremendous increase in capacity utilization is the source of the continual decline in average prices as measured by average revenue per passenger-mile in the U.S. airline industry since 1977. However, this increase in capacity utilization was only achieved because of the presence of a substantial number of price-responsive airline passengers. Although average prices have continually fallen, the variation in prices paid for the same flight has grown substantially since de-regulation. It is not unusual to see ratios on order of 5 to 1 for the highest to lowest-priced economy class ticket for the same origin/destination pair purchased at different times or with different travel restrictions. It is this price variation in combination with a price-responsive final demand that has allowed the airline industry to remain financially viable in the face of continual reductions in average revenue per passenger-mile since de-regulation.

Similar logic can be applied to competitive electricity markets. A large contingent of consumers that respond to hourly wholesale prices will increase the utilization rate of existing generation capacity and reduce the need for new investment. Price-responsive air travelers shift their travel plans in response to high prices for certain types of travel schedules and this increases airline load factors. Price-responsive electricity consumers alter their electricity demand in response to the high cost of certain patterns of consumption, resulting in a higher utilization rate of existing generation capacity. The presence of this price-responsive demand also will limit the ability of generators to exercise market power in the wholesale market, because they will face a significant likelihood of selling less electricity, even during high-demand periods, if they attempt to elevate market prices. If less market power is exercised, then market prices will come closer to reflecting the competitive market ideal, and the market will be served with less generating capacity. Both of these factors will lead to lower average delivered prices of electricity to final consumers. It is important to emphasize that, similar to the case of the U.S. airline industry, an important driver of these benefits is the existence of a number of price-responsive consumers.

These potentially large benefits illustrate why it is essential that the CPUC define the parameters necessary for robust retail competition as soon as possible if it intends to adopt retail competition as the long-term means of providing strong incentives for forward contracting, as described above and advocated by this Committee. A default provider rate should be put in place to protect consumers unable or unwilling to participate in a competitive retail market. The distribution or "wires" side of the UDC should be separated from the competitive retail or "supply" side of the UDC. As discussed in the October Report, with these provisions in place, consumers have the greatest opportunity to capture all of the benefits associated with a competitive electricity market. With a fixed default provider rate set at or near the CTC rate freeze level, and with the unbundling of local distribution from supply, consumers in San Diego can only benefit from the presence of retail competition. Similar logic applies to consumers in the SCE and PG&E service area, if the CTC recovery rate is changed to a fixed per unit charge on each MWh of load served in the UDC's service territory. Again, with a fixed default provider rate, these customers too can only benefit from retail competition. In addition, as discussed above, the more retail customers decide to vary their electricity consumption based on hourly wholesale prices, the more efficient the wholesale market will become. Our proposal will not force retail customers to become active wholesale market participants, as is the case under the current CPUC retail pricing policy for SDG&E. Under our proposal, some customers will choose voluntarily to vary their demand on an hourly basis based on rate schedules offered by the UDC's supply business or by competing ESPs.

Under-Scheduling in California Electricity Market

Since the first summer of operation of the California electricity market, during high load conditions there has been significant under-scheduling of load and generation on a day-ahead and hour-ahead basis relative to real-time electricity consumption and production. Under these system conditions, substantial amounts of generation and load often do not submit day-ahead or hour-ahead schedules and instead choose to trade in the ISO's real-time imbalance energy market. Trading a significant amount of load and generation in real time can considerably reduce system reliability. As a result of this concern, in mid-August of 1999, the ISO Board implemented a Replacement Reserve procurement mechanism and cost allocation scheme designed to eliminate the reliability problems caused by large quantities of generation and load showing up in real-time during high load hours.[14]

This section describes the Replacement Reserve cost allocation scheme implemented in August of 1999 and its unintended consequences for the exercise of market power. We then describe another response of the ISO to under-scheduling—out-of-market calls to out-of-control area generation unit owners. We go on to suggest three mechanisms that the ISO can use to alter the incentives for the under-scheduling by load and generation. Finally, we recommend a combination of these three mechanisms that can largely eliminate the under-scheduling problem.

The ISO's Replacement Reserve Cost Allocation Scheme

The ISO's new method (implemented in August 1999) for allocating replacement reserve costs strongly contributed to the high prices observed in June of 2000. Unfortunately, this change significantly enhanced the ability of generation owners to set high prices in the energy and ancillary services markets during high demand periods.

The Replacement Reserve penalty was designed to encourage more accurate forward (day-ahead and hour-ahead) scheduling by generators and loads. Under this mechanism, the ISO purchases additional Replacement Reserves when it estimates that an insufficient amount of generation and load has been scheduled on a day-ahead and hour-ahead basis relative to its forecast of system load. It is important to emphasize that because the ISO rules require all

[14] On August 22, 2000, the PX proposed to lower its price cap from $2500/MWh to $350/MWh. The likely impact of this change will be analyzed in the MSC's price cap memo to be release concurrently with this report.

forward schedules to be balanced, it is necessarily the case that if generation is under-scheduled then so is load, and vice versa.[15] Without the additional procurement caused by under-scheduling of generation and load, the ISO typically sets the demand for Replacement Reserve at less than 400 MW during peak-hours and zero MW during the off-peak hours. However, during some of the high load hours of June 2000, the ISO procured more than 6,000 MW of Replacement Reserve because of under-scheduling of load and generation. System reliability would be at considerable risk if the ISO went into an operating day with a difference between forecast system load and the sum of all day-ahead schedules equal 8,000 to 10,000 MWh.

To address this reliability concern the ISO implemented a scheme to purchase additional Replacement Reserve and allocate the costs of these additional purchases. Under this scheme, these additional purchases of Replacement Reserve are charged to the Scheduling Coordinators (SCs) with hour-ahead load schedules less than their real-time energy consumption in proportion to the magnitude of this additional real-time energy consumption. The Replacement Reserve penalty is also charged to SCs with day-ahead generation schedules in excess of the amount of real-time energy they provide in proportion to the magnitude of this under-supply of scheduled energy. However, during high load periods, the only generators producing less than their day-ahead or hour-ahead energy schedules are those that have had a forced outage after submitting their day-ahead or hour-ahead energy schedule.

The March 1999 Report of the MSC described the perverse incentives the Replacement Reserve cost allocation scheme would create for generators and loads participating in the PX and ISO energy markets and strongly advocated against the implementation of this market rule change.[16] This scheme effectively increases the costs to loads of shifting their purchases of energy to the real-time market, because the ISO purchases additional replacement reserves and charges these costs to the loads that schedule less than their actual consumption on an hour-ahead basis. Crucially, this scheme also *increased* the expected revenues available to generation unit owners from under-scheduling.

The combination of the Replacement Reserve cost allocation scheme and the June 2000 ISO price caps on adjustment bids and real-time energy provided load-serving entities with an incentive to bid a zero demand into the PX at a price of $750/MWh. The PX market rules require all incremental adjustment bids (INCs) to be greater than or equal to the unconstrained PX price and all decremental adjustment bids (DECs) to be less than or equal to the unconstrained PX price. However, the ISO would reject all INC bids above $750 and all DEC bids below -$750. Therefore, loads must bid a zero demand into the PX at $750 to guarantee that the unconstrained market-clearing price in the PX was no greater than $750, so that PX participants could submit $750 INC bids into the ISO congestion management process. If the unconstrained PX price was greater than or equal to $750/MWh, because the ISO's congestion management process will not accept INC adjustment bids above the PX unconstrained price,

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[15] Consequently, it is impossible to assign blame to load or generation for underscheduling in the forward markets. Fundamentally, the underscheduling problem is due to disagreement between load and generation about the appropriate forward price of energy in a given hour. If the forward price were lower, load would be willing to schedule more in the forward market. If the forward price were higher, generation would be willing to schedule more in the forward market.

[16] Wolak, Frank A., Nordhaus, Robert, and Shapiro, Carl, "Report on Redesign of Markets for Ancillary Services and Real-Time Energy," March 25, 1999.

UDCs would be exposed to potentially high congestion usage charges and constrained PX prices significantly higher than $750/MWh. Because of this exposure, UDCs had an incentive not to bid demand into the PX at a price at or above the ISO's price cap even if it meant incurring additional replacement reserve costs for unscheduled load.[17]

We should emphasize that this incentive for load-serving entities to bid zero demand into the PX at prices above the ISO real-time price cap has existed since the start of the California market. In this way, load-serving entities use the ISO's real-time price cap to protect themselves from high day-ahead prices in the PX. Although there was some concern about extent of under-scheduling of load and generation during the first two summers of ISO operation, the extent of under-scheduling never reached the levels it did during June 2000. The imposition of the Replacement Reserve cost allocation scheme in August 1999 created the possibility of an effective real-time energy price for generation unit owners double the real-time price cap on energy. This created significant incentives for generation unit owners to bid significantly higher prices in the PX markets. The steeper aggregate supply bid curve in the PX resulted in less energy clearing in the day-ahead market, and greater under-scheduling of load and generation. If the Replacement Reserve cost allocation scheme were eliminated or modified so that the effective price for supplying imbalance energy was always less than or equal to the ISO price cap on real-time energy, this very strong incentive for under-scheduling of load and generation would be eliminated.

If the Replacement Reserve cost allocation scheme is maintained, something we do not necessarily recommend, the above mentioned problem could be eliminated if the PX changed its rules on allowable INC and DEC bids by its market participants. Under the ISO's day-ahead congestion management protocols, the difference between an INC bid and a DEC bid for an SC across a given transmission path gives that SC's willingness to pay to use an additional MW of transmission capacity. The absolute level of a SC's INC and DEC bids across a transmission path are irrelevant to the process the ISO uses to determine day-ahead prices for transmission capacity. This rule on INC and DEC bids by PX participants is routinely violated by other SCs. Other SCs routinely submit INC bids below the PX's unconstrained price or DEC bids above the PX's unconstrained price.

The Replacement Reserve cost allocation scheme also provides very strong incentives for generation unit owners to under-schedule. To take an extreme case, generators supplying real-time energy at $750/MWh that also sold their capacity in the Replacement Reserve market at $750/MWh effectively received $1,500 for each MWh of energy they supplied during June 2000. For this reason, the Replacement Reserve cost allocation scheme creates a very high opportunity cost for generators bidding into the PX day-ahead and day-of markets during high load conditions. By selling their output in the PX forward markets, generators give up the opportunity to earn high prices in both the Replacement Reserve market and the real-time energy market. Consequently, this very high opportunity cost to forward market scheduling during high load days caused generators to bid very high prices in the PX markets. These high-priced bids set very high day-ahead and day-of energy prices and resulted in significant amounts of

[17] Because the ISO typically buys less replacement reserve than the amount of unscheduled energy (even during the high load periods of June 12-14, 2000) even if the replacement market cleared at $750/MW, the replacement reserve charge for each MWh of unscheduled load would be less than $750/MWh.

forecasted energy demand going unscheduled in advance of the ISO's real-time market. In this way, the ISO's Replacement Reserve procurement policy and cost allocation scheme enhanced the ability of generators to exercise market power in California energy markets.

The Replacement Reserve scheme creates a further incentive for generators to avoid scheduling all of their expected production in advance. SCs that fail to meet their hour-ahead energy schedules in real-time are assessed a Replacement Reserve penalty on this magnitude of under-production. However, these SCs also must purchase this amount of under-production as imbalance energy at the real-time energy price. During the extreme load conditions in June 2000, when the price of Replacement Reserve was $750/MWh and the price of real-time energy was $750/MWh, the per unit charge for under-supply of energy was significantly in excess of $750/MWh, because of this Replacement Reserve penalty. Consequently, a very easy way for a generation unit owner to avoid any risk of this penalty was to schedule on a day-ahead or hour-ahead basis only what it was virtually certain it could supply in real-time. In practice, a generation unit owner will weigh the probability of a unit outage and the corresponding penalty against the opportunity cost of keeping generation capacity out of the forward market and bid and schedule capacity so as to maximize its expected profits. By increasing the cost to a generator of failing to meet its hour-ahead energy schedule, this aspect of the Replacement Reserve penalty scheme further increased the incentives for generators not to schedule their expected real-time output on a day-ahead or hour-ahead basis.

The preceding discussion has shown that despite its intentions to the contrary, the Replacement Reserve penalty scheme increases the incentives for generators to under-schedule in the day-ahead and hour-ahead markets. In addition, because PX participants cannot submit adjustment bids above the ISO's price cap, this creates an incentive for loads to bid to set PX prices at or below the ISO price cap. It is important to emphasize that neither load nor generation is to blame for under-scheduling, because the ISO only accepts balanced schedules from SCs on a day-ahead and hour-ahead basis. By paying the Replacement Reserve price and the real-time energy price to generators supplying imbalance energy, the opportunity cost of selling energy in the day-ahead or hour-ahead markets can at least double during very high load hours. During hours with very high load, the Replacement Reserve penalty scheme pays generation (that is virtually certain to be providing energy in real-time) not to schedule in day-ahead and hour-ahead markets. This Replacement Reserve payment to generators is financed through the penalty that is charged to SCs that consume more energy in real-time than they schedule on an hour-ahead basis. These incentives for forward market bidding and scheduling created by the current Replacement Reserve scheme are a major factor behind the high average energy prices during June of 2000.

Out-of-Market Calls to Out-of-Control-Area Generation Unit Owners

Significant amounts of under-scheduling by loads and generators in the California market have led to another problem for the ISO operators, particularly during days with unexpectedly high demand. Several times during both May and June of 2000, the ISO operators have felt that the likelihood that the amount of capacity bid into the ISO's energy and ancillary services markets was insufficient to meet the ISO's forecast of system load during certain hours of the day. At these times the ISO operators will contact market participants outside of the ISO control area early in the day in which a shortfall might occur to ask them to bid into the ISO's real-time energy market. Although these unit owners sometimes do submit bids, more often the ISO operator must instead arrange a commitment to purchase energy for more hours than those in which the shortfall is expected to occur and at prices above the ex post real-time price in order to avoid a system emergency. There has even been at least one instance when an out-of-control area market participant withdrew its bids from the ISO's real-time energy bid stack and was subsequently called to provide energy in an out-of-market call.

These out-of-market purchases from generation unit owners located outside of the ISO control area create an incentive for withholding by generation unit owners located outside of the ISO control area that is virtually impossible to correct with any actions in the short term. This problem is the major reason for our earlier recommendation that the UDCs be able to forward contract with market participants outside of the ISO control area. This freedom to contract is crucial to reducing the exercise of market power by out-of-control area generation unit owners through these out-of-market calls.

Disciplining this sort of withholding behavior is virtually impossible because energy supplied from outside of the ISO control area cannot be identified with a specific generation resource. The ISO cannot order this resource owner to produce in real-time if they do not submit a bid to the ISO's energy or ancillary services markets, as the ISO is able to do with resources located inside the ISO control area. The ISO cannot even verify if this market participant in fact has a resource from which it might obtain the necessary energy. To the ISO operators, energy supplied from out of the ISO control area is simply a flow on a transmission path. Attempting to punish a market participant located outside of the ISO control for actions it takes is largely ineffective, because this market participant can arrange a deal with another market participant outside of the ISO control area and therefore circumvent any sanctions or penalties the ISO might impose.

Three Mechanisms for Dealing with Under-Scheduling

We describe three different mechanisms for providing incentives to generation unit owners and load-serving entities to reduce the amount of under-scheduling in the California electricity market. All of these mechanisms increase the expected cost of participating in the ISO's real-time energy market for generation unit owners or load-serving entities. Unless load-serving entities expect that purchasing electricity in the ISO's real-time market will be more expensive than any of the available forward energy markets, they will continue to prefer to under-schedule. Unless generation unit owners expect to earn less from selling in the ISO's real-time market than from selling in any of the available forward energy markets, they will also continue to prefer to under-schedule. Because the California market design relies on the voluntary scheduling decisions of SCs, the only way for the ISO to reduce the amount of under-scheduling is make the real-time market less lucrative for load-serving entities and generation unit owners relative to the available forward markets. This incentive is missing from the ISO's current procedure for reducing the extent of under-scheduling.

The first mechanism would encourage accurate forward market scheduling by instituting a real-time trading charge on both load and generation. All SCs would be charged a per-unit trading charge on the sum of the absolute value of all energy imbalances in each congestion zone during the hour. For example, if a SC had a day-ahead schedule of 500 MW in a congestion zone during a given hour, but generation units scheduled through that SC produced 400 MW in that hour and loads scheduled through that SC consumed 550 MW in that hour, its total hourly energy imbalances in that congestion zone would be 150 MW = 100 MW + 50 MW. This SC would be liable for a total hourly trading charge in that congestion zone equal to 150 MW times the per unit trading charge. All imbalance energy purchases and sales, including out-of-market calls would be liable for this imbalance energy charge. By adjusting the magnitude of this real-time trading charge, the ISO could increase the incentives for accurate forward market scheduling by all SCs. This trading charge should be significantly larger than the PX's trading charge in order to encourage accurate forward scheduling. Any excess revenues collected from this trading charge could be refunded to SCs on an annual basis based on their total annual imbalances relative to the sum of their annual energy consumption and generation. Those SCs with the smallest normalized annual energy imbalances would receive the largest refunds. Refunds would be paid only to those SCs with normalized annual energy imbalances less than some target level, such as 5%.

The second mechanism would retain the current Replacement Reserve procurement scheme, but use it to provide an incentive for generators to accurately forward schedule. This can be provided within the current mechanism by assessing a penalty on any SC from whom the ISO procures real-time generation in excess of their hour-ahead energy schedule. Under this scheme, even those generators that respond to real-time dispatch instructions from the ISO to supply significantly more than their day-ahead energy schedules would cause this Replacement Reserve penalty to be assessed. These generators could factor the expected value of this penalty into their real-time energy bids that they submit to the ISO, if this penalty is in fact passed on to them. This mechanism should allow SCs to produce some level of real-time generation in excess of their hour-ahead energy schedules without being assessed the Replacement Reserve penalty. For example, an oversupply of less than 5 percent of a SC's hour-ahead energy schedule (recall that all forward market schedules are balanced) would not result in the assessment of a Replacement Reserve penalty. However, over-generation relative to schedule in excess of this amount would result in the assessment of a Replacement Reserve penalty regardless of the cause.[18]

We recommend setting the Replacement Reserve penalty as follows. SCs having any generation unit supplying more than 5 percent of its hour-ahead schedule in imbalance energy would be assessed a penalty equal to the Replacement Reserve price per MWh of energy it provides from capacity sold for Replacement Reserve. Suppose a SC scheduled a generation unit for 100 MW and sold 50 MW of Replacement Reserve at price $25/MW of from this unit. If the unit supplied 150 MW of energy during the hour, the SC would be liable for a Replacement Reserve penalty of (150 – 105)*25 = $1125 for that unit. This mechanism would create very strong incentives for SCs to schedule their expected real-time production on an hour-ahead basis. SCs with generation units supplying imbalance energy beyond 5 percent of the

[18] We recognize that our proposed approach, by charging generator that produce significantly more energy in real time than they scheduled on an hour-ahead basis, appears to discourage generators from making available additional capacity, not scheduled on an hour-ahead basis, that is needed in real-time. However, we firmly believe that, if the ISO is committed to this approach, generators will quickly respond to the resulting incentives and schedule their available capacity on a day-ahead or hour-ahead basis, thus alleviating the under-scheduling problem.

unit's hour-ahead schedule with no associated Replacement Reserve sales from that unit would be liable for the remaining additional Replacement Reserve costs. These costs would be assessed to SCs in proportion to the amount of imbalance energy each unit scheduled by that SC supplies in excess of 5 percent of its hour-head schedule.

Changing the Replacement Reserve penalty obligation to generators has the very attractive feature that it pays generators very little for supplying Replacement Reserve during hours when Replacement Reserve does not actually provide reserve. During the high load hours, Replacement Reserve purchases are a mechanism used by the ISO to guarantee sufficient generating capacity is available to serve its forecast of system load because of under-scheduling by load and generation. Under this scheme for charging generators for these additional purchases, during the hours that a generation unit owner submits an hour-ahead energy schedule that is significantly below its expected real-time energy production, this unit owner will refund a significant portion of the replacement reserve payments. This refund is proportional to the extent that the SC supplies significantly more energy in real-time than it scheduled on an hour-ahead basis in that congestion zone.

Under our recommended approach, generation units with unloaded capacity that has not been sold in any of the ancillary services markets face a significant risk of receiving an extremely low effective real-time energy price if they supply too much in real-time. Besides encouraging accurate forward scheduling, this approach will encourage aggressive bidding in the Replacement Reserve and other ancillary services markets, because generators will prefer to refund a portion of ancillary-services revenues rather than pay out-of-pocket the replacement reserve penalty for supplying too much energy in real time.

The third mechanism to encourage accurate scheduling is charging the cost of out-of-market calls to generators located outside of the ISO control area to SCs in proportion to the amount that their actual load is above their hour-ahead schedule. For the reasons described above that in-state generators would be willing to sign forward contracts with the UDCs, the generation unit owners located outside the ISO control area should be interested in signing similar contracts. For the vast majority of the hours of the year, prices in California are higher that those in the surrounding states. In order to provide the UDCs with the financial incentives to sign such forward contracts, the ISO must charge the cost of all out-of-market calls made to out–of-control area generation unit owners to the SCs in proportion to amount that their actual load exceeds their hour-ahead schedule. This will create incentives for UDCs to sign the amount of forward financial contracts necessary to eliminate the incentives out-of-control area market participants have to wait until the real-time to be called by the ISO to supply energy.

Recommendations for Reducing Under-Scheduling

We believe that the following combination of the three mechanisms described above can effectively eliminate the current incentives for under-scheduling by loads and generators. The first component is a real-time trading charge on SCs with a refund to those whose annual total imbalance energy transactions (the annual sum of hourly real-time purchases plus sales) is less than 5% of their total annual energy production plus consumption. The refund received by these SCs should be in proportion to how accurately they schedule on an annual basis. The second component is a modified replacement reserve cost allocation mechanism. SC's would be assessed two types of replacement reserve charges. For those generation units sold as Replacement Reserve, any real-time production beyond 5% of the unit's hour-ahead schedule would require a refund of the Replacement Reserve price the unit received per MWh of energy it provides. Generation units not sold as Replacement Reserve would be liable for the remaining additional Replacement Reserve costs in the form of a per MWh charge for energy produced in real-time in excess of 5% of their hour-ahead energy schedule. The final component is to charge out-of-market calls to out-of-control area market participants to SCs in proportion to the amount that their hour-ahead schedule is below their real-time consumption of electricity. The real-time trading charge and Replacement Reserve charge should also be imposed on out-of-market calls to out-of-control area market participants.

We urge the ISO to consider this recommendation as a substitute for the current Replacement Reserve procurement policy, recognizing that our recommendation will need to be carefully reviewed by the ISO staff and stakeholders before implementation. However, it is our view that each aspect of the recommendation addresses a specific aspect of the incentives associated with under-scheduling by loads and generators, so that three mechanisms should be included in any proposal to eliminate this reliability problem.

One challenge to implementing the real-time trading charge on out-of-market calls to market participants located outside of the ISO control area is the ISO's stated willingness to pay whatever price is necessary to maintain system reliability. This creates the obvious incentive for out-of-control area market participants to hold out for higher prices. For precisely this reason, the ISO should consider altering its policy for out-of-market calls to out-of-control area generators to pre-commit itself not to pay more than its real-time energy price cap. The ISO operators should only be given the discretion to negotiate the duration and hourly quantities of energy for out-of-market calls to market participants outside of the ISO control area. It our understanding from ISO operators that a major concern of market participants outside of the ISO control areas is to obtain a sufficiently long commitment from the ISO for an out-of-market call. It is hard to imagine that the ISO cannot procure a sufficient amount of energy outside of the ISO control area to maintain system reliability at the current $250/MWh price cap by increasing the duration of the out-of-market call and the quantity of energy supplied. Capping the maximum price at which the ISO is willing to pay for out-of-market calls will provide a finite outside alternative for bargaining between out-of-control area generators and load-serving entities in California over long-term contracts for energy supply. To provide an additional incentive for out-of-control area market participants to sell into the PX and ISO markets, the ISO should also post on its web-site the price paid, quantity purchased, duration of the purchase and the seller for all out-of-market calls to out-of-control area market participants. This posting should occur as soon as the deal between the ISO and the market participant is struck. Because the terms for supplying this energy are negotiated by the ISO management, all market participants should have the opportunity to determine the prudency of these purchasing decisions. Public reporting of these prices should also allow other market participants, federal and state regulators, and other interested parties to encourage these generation unit owners to participate in the ISO's forward markets rather than wait to supply energy out-of-market. At a minimum, posting of this information will also encourage competition among out-of-control area generators to provide such out-of-market energy. For all of these reasons, out-of-market calls to out-of-control-area generators should not be subject to any confidentiality restrictions.

Balancing Reliability and Market Power Concerns

There is an intimate relationship between reliability and market power in all competitive electricity markets. It is virtually impossible to distinguish a reliability concern from a market power concern, because almost anything that can contribute to reduced system reliability presents an opportunity for a market participant, generator or load-serving entity, to exercise its market power. For example, if demand is sufficiently high, withholding capacity can create a grid reliability problem, which creates a severe market power problem because a specific generation unit owner will be needed to serve the market demand regardless of its bid price. A significant fraction of the October Report was devoted to illustrating the equivalence of local reliability problems and local market power problems. The same logic applies to the general case of grid reliability and market power. Designing market rules for reliable grid operation without considering the market power implications of these rules can lead to extremely high prices during certain time periods. By the same logic, operating the ISO grid without consideration for incentives can result in high prices and the exercise of market power.

The ISO has often had to determine whether a market rule change meant to improve system reliability significantly enhances the ability of generators to exercise market power. However, concerns about market power have not always been given sufficient weight in formulating market rule changes intended to enhance system reliability, despite concerns expressed by this Committee. The Replacement Reserve penalty is one market rule change that could have been avoided, had market power concerns been given greater weight. As discussed above, the March 1999 MSC report warned against many of the adverse impacts that arose during June 2000. There are several recent and proposed market rule changes with the potential to create analogous future market-power problems. In the light of the events of June 2000, it would seem prudent for the ISO to take an alternative approach to designing market rule changes to enhance system reliability.

We favor an approach that explicitly recognizes that market participants take actions that harm or benefit system reliability when it is in their financial interest to do so. We are not suggesting that any market participants intend to imperil system reliability; we are merely pointing out that market participants tend to respond to financial incentives. If the ISO would like market participants to take actions, which maintain system reliability, it must design market rules that provide financial incentives for market participants to take these actions. As discussed earlier, generators and loads have not been submitting accurate forward energy schedules, because it is has not been in their financial interest to do so under the current market rules. Reliability problems do not exist separate from economic incentive or market power problems. Consequently, many reliability problems the ISO faces should first be addressed from the perspective of designing markets to provide incentives for all ISO market participants to maintain system reliability. Because the California ISO market design allow generators to self-schedule generation units, the ISO operators do not have the same options to maintain system reliability as those available to operators in the Eastern ISOs. Therefore, it is imperative that generation unit owners be provided with financial incentives to schedule in the forward market and therefore increase system reliability. The ISO operator cannot order a generation unit to turn on a day-ahead basis, as is the case for all of the Eastern ISOs. The California ISO operators must instead rely on PX and ISO markets to create incentives for generators to supply energy and ancillary services to maintain system reliability.

We consider three examples of recent and proposed market rules changes designed to enhance system reliability that raise potentially serious concerns about market power. The first is the ISO's alternative out-of-market (OOM) payment scheme. The second is the ISO's proposed ten-minute settlement scheme. The third is the proposed PG&E hydro divestiture agreement between the ISO and PG&E.

The ISO's recently adopted alternative OOM payment scheme has increased the attractiveness to generators of not participating in any of the California energy and ancillary services markets. The OOM payment scheme pays generators called out of market both a capacity component and energy component as well as verifiable fuel related start-up costs and gas imbalance charges that result from the ISO OOM call. The capacity component is a weighted average of the day-ahead spinning reserve and non-spinning reserve prices during the three preceding comparable days. The energy component is a weighted average of the day-ahead and hour-ahead PX energy prices and the ISO real-time energy price for three preceding comparable days. During a period of high demand, the revenues earned from an out-of-market call under this payment mechanism can be significantly greater than what a generator would earn from participating in the PX energy and ISO energy and ancillary services markets. Similar to the incentives provided by the Reliability Must-Run Contract "A" payment scheme, generators will therefore prefer to stay out of any of the PX or ISO markets to instead be called under the terms of this alternative OOM payment scheme. Generators called under the OOM mechanism have also negotiated runtime commitments beyond a single hour. This creates an additional incentive for generators not to participate in the PX or ISO markets and therefore artificially drive up prices in these markets.

Unless the attractiveness of an OOM call is reduced, generators will have incentives during certain hours not to participate in the PX energy and ISO energy and ancillary services markets. To insure active participation in the PX and ISO markets, an out-of-market call must always be less attractive to a generator than participating in the formal California energy and ancillary services markets. Consequently, based on these market power concerns, the current OOM payment mechanism should be eliminated and replaced with a scheme that is always less attractive than participating in these markets.

There are two potential market power problems associated with the ISO's ten-minute settlement scheme. The first relates to what the mechanism calls residual imbalance energy. Under this scheme the ISO attempts to make the distinction between generators who deviate from their schedules because they responded to the ISO's dispatch instructions in a previous settlement period and those who deviate from their schedules without instructions from the ISO. Attempts to distinguish between different types of energy supplied within the same time period creates incentives for generation unit owners to have their energy classified as the one that is paid the higher price, often with detrimental impacts on system reliability and spot price volatility. Specifically, under this scheme it is possible for two generators with the same forward schedules and real-time production to be paid differently by the ISO for imbalance energy they supply. The other problem associated with the ten-minute settlement is the creation of potentially two prices within each ten-minute interval in order for the ISO operator have the tools to provide the necessary signals to generators to meet the ISO's frequency control requirements. The creation of two separate prices within the same time interval for the same goods creates similar problems to those described above. The reliability problem that led to the creation of two prices within a ten-minute interval can be overcome by setting a single price at a five-minute interval. All other US ISOs currently operating set prices at five-minute intervals for precisely this reason. Consequently, the ISO may wish to re-consider whether its current 10-minute settlement scheme has adequately addressed the potential market power problems that appear to exist. There are several 5-minute settlement alternatives that create stronger incentives for maintaining system reliability.

A final example of this phenomenon is the proposed agreement between the ISO and PG&E on the divestiture of PG&E's hydro assets. The agreement for how these assets will be bid into the PX and ISO markets appears to be attractive from the perspective of system reliability, but less so from the perspective of limiting the exercise of market power. Given the events of the past two months, any change in market structure that might increase the opportunities for any market participant to exercise market power should be avoided. Our concern with market power follows from the fact that capacity will be transferred from a market participant with a strong incentive to keep wholesale energy and ancillary services prices low, because it is subject to a retail rate freeze and is a net demander of wholesale electricity, to a market participant with an incentive to maximize wholesale energy and ancillary services prices. After divestiture, these assets will be operated by an unregulated affiliate with strong incentives to achieve high wholesale energy and ancillary services prices. There are number of market power concerns with the current proposal to transfer the assets. It our understanding that the Market Monitoring Committee of the PX shares these and other concerns about the likelihood that the proposed agreement will limit the ability of the unregulated affiliate to exercise market power in the PX and ISO markets.

First, this agreement appears to violate the basic premise of market power mitigation described above. The plan does not appear to offer any guarantee that wholesale prices will not be adversely impacted by this asset transfer. The unregulated entity's incentive to achieve high wholesale prices at all levels of output has not been altered. Whether it is able to achieve these prices through its own bidding behavior or that of its competitors is irrelevant. Its incentive to exercise market power has not been altered.

A second concern relates to the minimum bidding requirements and bid caps. Every competitor would like to have a script describing how other firms will behave under a variety of system conditions. This firm can then formulate its optimal strategy taking into account how these scripts say the firm's competitors will respond. One can think of the agreement's bidding requirements and bid caps as the script describing how the unregulated affiliate will behave. Knowledge of this script should help this firm's competitors to do a better job of setting high prices than if they did not have this script containing the new owner's bidding strategy.

The final point concerns the decision that the CPUC takes on retail competition. If the CPUC decides to make all of the UDCs subject to a retail rate freeze, then they will have strong incentives to keep wholesale rates down. However, without these assets in the regulated affiliate of PG&E, it will have much more difficulty limiting wholesale prices. Consequently, delaying the decision on the divestiture until the CPUC clarifies what it plans to do on retail competition will significantly limit the potential market power risk associated with divesting these assets. Given the events of May and June 2000, creating a new unregulated player with a financial interest in achieving high wholesale energy prices cannot help to reduce the exercise of market power in the PX and ISO markets.

Summary of Recommendations

In our view, if the market rules recommended in previous MSC reports had been implemented by the end of 1999, average prices in the ISO's energy and ancillary services markets during May and June 2000 would have been significantly less than actually transpired. However, given the unexpectedly high loads that occurred in the ISO control area early in June, it is likely that energy price spikes would have occurred during these time periods, albeit for a significantly smaller number of hours. In addition, the impact of these price spikes on retail consumers in San Diego would have been significantly less. As discussed above, had all of the UDCs been able to forward contract freely at quantities close to their total net short position in each hour, they would have been completely insulated from these wholesale market price spikes.

If the market design flaws described in this report had been corrected, the price spikes during a very, very hot period early in June accompanied by a significant amount of generating capacity forced-out would have looked like the result of a competitive market during conditions of tight supply. For these reasons, the best course of action appears to be for the ISO, PX, CPUC, the UDCs and the relevant state agencies work to correct these remaining market design flaws as soon as possible.

Even if the California energy market was still under the old vertically-integrated regulated regime, the events of June 2000 would have provided strong evidence in favor of the following view. The California ISO control area is extremely reliant on imports to meet its obligations during high load conditions. The aging stock of generation capacity in the California ISO control area is increasingly unreliable. There is a pressing need for new generation capacity in the California ISO control area in the near future. Various parts of the bulk transmission grid in the ISO control area are increasingly unreliable. Substantial transmission upgrades are needed throughout the areas served the three UDCs to improve grid reliability and the efficiency of providing electricity to California consumers. These same conclusions apply in the new competitive wholesale electricity market. Addressing these issues is of the highest priority.

However, the focus of this report is on problems specific to the current ISO and PX markets that caused the energy and ancillary prices that occurred in June 2000. This report identified the four major problems described is detail above and suggested various remedies for these problems. The major recommendations of this report are summarized below. Although the first four recommendations require action by the CPUC, they are essential to a workably competitive wholesale electricity market.

- Eliminate as soon as possible restrictions on how, with whom and how much forward contracting UDCs can engage in energy and ancillary services. If there is desire to retain the spirit of the PX buy/sell requirement during the CTC recovery period, it should be modified to the requirement that the UDCs use the PX as their scheduling coordinator. There should be no requirement for the UDCs to bid energy or load into any of the PX markets.

- Immediately impose a retail rate freeze on San Diego Gas and Electric's customers at or near the CTC recovery level. Determine as soon as possible, following the imposition of this retail rate freeze, a fixed default provider rate and begin the process of separating SDG&E (financially or legally) into a regulated distribution company and an unregulated supply company. This supply company has the default provider obligation and must purchase distribution services at the regulated rate from the regulated distribution company. In this process, clarify which services, for example, metering and meter reading, are regulated services provided by the UDC and which are provided by competitive suppliers.

- For the remaining providers still under the CTC recovery mechanism, alter the CTC recovery mechanism to remove the competitive advantages in retailing it provides to the UDCs. One such approach is to convert the CTC payment mechanism to a fixed per unit charge to all energy consumed in the UDC's service territory. Once this change has been made, the process should begin for defining the necessary initial conditions for robust retail competition.

- Institute a real-time trading charge on SCs on the sum of the absolute value of both imbalance transactions by its generation and load in each congestion zone. This congestion charge should be significantly larger than the PX trading charge. This charge should be refunded to SCs who meet a minimum requirement for accurate scheduling on an annual basis, with higher per unit refunds given to SCs that schedule more accurately.

- Immediately eliminate the ISO's current Replacement Reserve penalty scheme and replace it with one that charges SCs for energy they supply in a given congestion zone in real-time greater than 105% of their hour-ahead energy schedule in that congestion zone.

- Institute a mechanism for charging out-of-market calls to out-of-control area market participants to SCs in proportion to the amount of energy they consume in real-time beyond their hour-ahead energy schedule.

- Place greater emphasis at both the ISO Board and staff level on the market-power implications of proposed market rule changes, recognizing that reliability and market power concerns are inextricably linked. Many reliability problems are caused by inappropriate market incentives. From this perspective, re-consider (1) the current out-of-market payment mechanism, (2) the ISO's 10-minute settlement market, and (3) the PG&E hydro divestiture agreement with the ISO.