Comments on "Staff Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electricity Market"

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The Need for Market Power Mitigation in California

We would first like to commend the Commission staff for its efforts in formulating several prospective market monitoring and mitigation plans that recognize the existence of market power in the California electricity market. As the Market Surveillance Committee (MSC) has emphasized in all of its reports, market power in the California electricity market has produced prices significantly in excess of the competitive market benchmark since as early as July of 1998. The MSC has periodically reported monthly measures of market performance equal to the difference between average electricity prices and average electricity prices that would have been obtained in the absence of the exercise of market power expressed as a percentage of actual electricity prices.

The September 6, 2000 MSC Report presented this index of market power for the first six months of 2000.[1] This report showed that the extent of market power exercised in the California electricity market was the highest it had ever been in June of 2000. The average electricity price for June 2000 was shown to be 2.82 times the average competitive benchmark price for that month. Because of increases in the costs of NO_x emissions permits during 2000, our methodology now accounts for the cost of purchasing these emissions permits in computing our estimate of each unit's operating costs. Therefore, in addition, to adjusting the marginal cost of producing electricity for the daily price of natural gas, we also include an adder to the marginal cost of producing electricity for certain in-state fossil generation units to account for current cost of purchasing the emissions permits necessary to produce electricity. Table 1 presents this updated market performance measure that accounts for the costs of purchasing NO_x emissions permits for each month of 2000. These monthly measures of market performance are also reported for 1998 and 1999. The theoretical foundation for this market performance measure and the details of its computation are described in Borenstein, Bushnell and Wolak (2000).[2]

TABLE 1

Monthly Indexes of Market Power for June 1998 to December 2000 MP(S) Index from BBW (2000)			
Month	**1998**	**1999**	**2000**
January	-	-0.021	0.174
February	-	-0.061	0.077
March	-	-0.063	-0.007
April	-	0.040	-0.103
May	-	0.007	0.210
June	-0.593	0.071	0.633
July	0.280	0.171	0.516
August	0.399	0.070	0.601
September	0.350	0.154	0.426
October	0.073	0.338	0.403
November	0.003	0.292	0.395
December	0.117	0.128	0.390

There are a variety of ways to interpret our measure of market performance. Suppose that PACT(S) is equal to the weighted average hourly price of electricity for month S. In computing this average price we weight each hourly price by the difference between total ISO load for that hour and the amount of must-take energy supplied during that hour. Suppose that PCOMP(S) is the weighted average hourly competitive benchmark price for month S computed as described in Borenstein, Bushnell and Wolak (2000).

The market performance measure, MP(S), is equal to

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[1] Wolak, Frank A., Nordhaus, Robert, and Shapiro, Carl, "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," September 6, 2000, available from http://www.caiso.com/docs/2000/09/14/200009141610025714.html

$$(PACT(S) – PCOMP(S))/PACT(S),$$

which is the difference between the average price and the average competitive benchmark price as a fraction of the average price. The maximum value of our index is equal to 1, which would occur is PCOMP(S) is equal to zero. Although larger values of MP(S) imply that a greater deviation from competitive benchmark pricing, the relationship between the amount market power exercised and the value of MP(S) is extremely nonlinear.

A more easily interpretable way to express information contained in MP(S) is as PACT(S)/PCOMP(S), the ratio of the average hourly price for month S to the average hourly competitive benchmark price for month S. It is straightforward to show that:

$$PACT(S)/PCOMP(S) = 1/(1 – MP(S)).$$

For example, MP(S) for June of 2000 given in Table 1 implies that PACT(S)/PCOMP(S) is equal to 2.72. This means that the average prices for June 2000 are 2.72 times the average competitive benchmark price for June 2000. This 2.72 figures is slightly less than 2.82 figures reported in the September 6, 2000 MSC Report, because of the inclusion of the cost purchasing NO_x emissions permits in the variable cost of in-state fossil fuel generating units. Applying this transformation to the values of MP(S), for July and August of 2000, we can see that the average hourly price was more than twice the average hourly competitive benchmark price for each of these months. Even December 2000 showed average actual prices that were more than 1.64 times the average competitive benchmark price. Table 2 reports the values of PACT(S)/PCOMP(S) for the period May 2000 to December of 2000. These figures illustrate the enormous deviations from competitive benchmark pricing during the latter half of 2000.

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[2] Borenstein, Severin, Bushnell, James, and Wolak, Frank, (2000) “Diagnosing Market Power in California’s Re-structured Electricity Market,” available from http://www.stanford.edu/~wolak.

TABLE 2

Monthly Average Price Ratios PACT(S)/PCOMP(S) for May 2000 to June 2000	
Month	**PACT(S)/PCOMP(S)**
May	1.26
June	2.72
July	2.07
August	2.51
September	1.74
October	1.68
November	1.65
December	1.64

Starting in early November with the Commission's "Order Proposing Remedies for California Wholesale Electricity Markets (Issued November 1, 2000)," natural gas prices in the state began to rise rapidly. Natural gas prices peaked in early December 2000 at more than \$50/MMBTU, coincident with the ISO's imposition of the Commission's soft cap on the ISO's energy and ancillary services markets. Since the imposition of the soft-cap California natural gas prices have been almost double prices in other parts of the United States. For example, the average difference between spot gas price at Henry Hub in Louisiana and the Topok delivery point in California from December 8, 2001 to mid-January 2001 was more than \$8/MMBTU. (The average price of spot gas at Henry Hub for this time period was significantly less than \$8/MMBTU.) For the period April 1, 1998 to December 7, 2001, the average difference between these spot prices was less than \$0.50/MMBTU.

One potential explanation for this divergence between California gas prices and those in the rest of the US following the imposition the soft cap on the ISO's energy and ancillary services market. Most of the merchant power producers in California are significant players in the US gas market and currently have some long-term contracts for gas delivery to California. Because of the almost daily Stage 3 system emergencies declared during December of 2000, all merchant suppliers recognized that virtually any gas-fired energy they produced would be needed by the ISO to meet demand. Consequently, because the soft cap policy allows generators to cost justify any bid in excess of $250/MWh during December of 2000 (this was reduced to $150/MWh effective January 1, 2001), these suppliers have a strong incentive to purchase their gas needs for electricity on the spot market. This allows them to store their low-priced long-term gas deliveries for use during the summer of 2001, when the Commission's soft cap will most likely no longer be in place. By this logic, the soft cap creates an artificial scarcity of natural gas in California, because generators are both buying all of their current natural gas needs for electricity generation on the spot market and taking delivery for storage for their gas deliveries under long-term contracts. The soft cap also artificially inflates average wholesale electricity prices, because all suppliers know that the soft cap allows any supplier to cost-justify it bid into the ISO's real-time energy market. Finally, the existence of the soft cap creates strong incentives for the gas affiliates of the merchant generators to sell spot gas to their generation affiliate at extremely high gas prices. This high gas price can then be used to cost-justify a very high electricity bid price under the Commission's soft cap policy. Because virtually all of the services that publish daily natural gas prices are based on surveys of actual natural gas trades, this behavior by the merchant power producers and their gas affiliates would result in the extremely high spot gas price differences between California and other points throughout the US that have been observed since early December of 2000.

Partly as a result of the large increase in natural gas prices in December of 2000, total spending on energy and ancillary services per MWh of load rose to more than $310/MWh for this month. The previous high occurred during August of 2000, when total spending on energy and ancillary services per MWh of load was $180/MWh and daily peak demands were as high as 45,000 MW. This increase in total spending per MWh of load occurred despite daily peak demands in the neighborhood of 30,000 MW during December 2000. But higher natural gas prices did not account for the entire wholesale electricity price run-up. The value of MP(S) for December 2000 exceeded the values for all months in 1998 and 1999 except August of 1998, a month when peak daily demands were as high as 45,000 MW. This combination of high natural gas prices and the exercise of significant market power combined to make total energy and ancillary services costs for December 2000 more than $6 billion.

For the year 2000, the average hourly difference between the total cost of purchasing flexible energy (total ISO load minus must-take energy) at the actual market price versus the competitive benchmark price was approximately $1 million dollars per hour. This implies an overpayment relative to the competitive benchmark price for flexible energy for the year 2000 of more than $8 billion. This overpayment calculation accounts for both the significantly higher natural gas prices and NO_x emissions permit costs in 2000 relative to 1999 in computing the competitive benchmark price. Computing the value of MP(S) for the entire year 2000, yields a value of 0.428, which implies that the average hourly price for 2000 was 1.75 times the average hourly competitive benchmark price for 2000.

During January and February of 2001, average energy costs remained very close to the levels that existed in December 2000 and natural gas prices in California remained more than double the values in the neighboring western states. Multiplying total energy and ancillary services costs for January and February 2001 by six yields a very rough forecast of total energy and ancillary services costs for 2001. This calculation results in a number that is close to $70 billion. This should be contrasted with total energy and ancillary services costs of $7 billion for 1999 and $27 billion for 2000. Dividing these figures by the total amount of energy delivered through the California ISO control area during each of these years, yields total energy and ancillary services costs per MWh of load of $33 in 1999 and $116 is 2000. Dividing our $70 billion estimate of total energy and ancillary services costs for 2001 by the total amount of energy delivered through the California ISO control area in 2000 (a conservative estimate of the amount energy delivered in 2001), yields $292 per MWh of load.

This $292 per MWh of load estimate for average energy and ancillary services costs for 2001 seems conservative when viewed relative to the current futures contract prices for electricity delivered to Palo Verde and the California-Oregon Border during the summer of 2001 sold on the New York Mercantile Exchange. On March 20, 2001, Palo Verde futures prices were $375/MWh for June 2001, $455/MWh for July 2001, $550/MWh for August of 2001 and $390/MWh for September of 2001. On this same day, California-Oregon Border futures prices were $335/MWh for June 2001, $395/MWh for July 2001, $500/MWh for August of 2001 and $450/MWh for September of 2001. The futures prices for both locations for the same months in 2002 are all in excess of $200/MWh. Although these prices are for electricity delivered to the California border, as emphasized by observers of the California market, and most recently in the February 6, 2001 MSC report, the behavior of spot electricity prices over the past two years provides strong evidence that all of the states in the Western Systems Coordinating Council (WSCC) are a single integrated wholesale market for electricity. Because California generation unit owners have the ability to sell outside of California and firms owning generation units outside of the State can sell surplus power into California, high prices in California will attract supply from generators located outside of California with surplus energy, which will drive up spot prices outside of the state. This process should continue until suppliers with generation located outside of the state are indifferent to selling their surplus energy inside or outside of California because spot prices in the two regions are approximately equal. This logic implies that these prices can be thought of as lower bounds on expected spot electricity prices in California during the delivery period of these futures contracts. Moreover, one lesson from previous MSC Reports is that the extent of market power exercised in California's energy markets tends to be very highly positively correlated with the extent of market power exercised in its ancillary services markets. Consequently, we can expect the extremely high electricity prices for the summer months of 2001 and 2002 to be associated with extremely high ancillary services prices, because the major opportunity cost of supplying ancillary services is the forgone variable profits from supplying electricity. This logic provides another reason for our view that $292 per MWh of load is a conservative estimate of the average cost of energy and ancillary services for 2001.

These numbers indicate that without significant market power mitigation from the Commission, California consumers and taxpayers can expect to continue to pay wholesale electricity prices vastly in excess of the competitive benchmark price for the next two years. Moreover, the California Department of Water Resources (DWR) recently released a summary of the forward contracts that it has signed or agreed to in principle for next two summers.[3] Although it is difficult to determine from this document the precise quantity of forward contract signed for the summers of 2001 and 2002, the information available does indicate that California must continue to purchase a significant fraction of its load on the spot market for the next two years. The limited amount of contract cover that the state has managed to negotiate voluntarily for the next two years reflects the economic fact described in the February 6, 2001 MSC report that no profit-maximizing firm will voluntarily give away market power that it possesses without an up-front payment that exceeds the increased profits available from exercising this market power.

Unless the Commission believes than an average wholesale energy and ancillary services price for 2001 ($292 per MWh of load) that is approximately ten times higher than the average wholesale energy and ancillary services price for 1999 ($33 per MWh of load) is just and reasonable, it must intervene to mitigate the enormous market power that will exist in the California electricity market for the next two years.

Ability of Staff's Recommended Plan to Mitigate Market Power in California

The Staff's recommended market power mitigation plan is inadequate to the task of protecting California consumers from the exercise of significant market power over the next two years. By mitigating market power only during Stage 3 conditions, the plan misses the vast majority of hours when significant market power is exercised in the California market. For example, none of the market power exercised during the summer and autumn of 2000 would be mitigated under the Staff's recommended plan, because the first Stage 3 did not occur until

[3] California Department of Water Resources, "Summary of California Department of Water Resources Power

December 7, 2000. This implies that almost $6 billion of the $8 billion of overpayment during 2000 due to the exercise of market power would not be mitigated.

The Staff's recommended plan also fails to recognize a very important point made in the February 6, 2001 MSC Report that it is impossible for an independent entity to determine if a declared forced outage reflects the fact that a plant is truly unable to run. The February 6, 2001 MSC report compared a declared forced outage to a sick day for a worker. Just as an employer cannot unequivocally determine if a worker that calls in sick is in fact truly unable to work, a plant inspector cannot determine if a power plant is truly unable to run. However, just as it is preferable to leave the decision about whether a worker is physically able carry out his job responsibilities to that worker, the decision about whether a power plant can operate should be left to the plant operator. It is important to note that the problem of verifiable forced outages has arisen in virtually every competitive electricity market, beginning with England and Wales electricity market.[4]

This non-verifiable forced outage problem implies that it is impossible for the ISO, the Commission, the California Public Utilities Commission and any other independent entity to determine conclusively whether a Stage 3 system emergency occurs because a large number of generators are truly unable to run or because it is very profitable for generators to create Stage 3 emergencies through their unilateral forced outage declarations. This creates two fundamental problems for the ability of the Staff's proposed plan to mitigate market power.

First, if the Staff's plan gives an exemption to its obligation for all units that have signed a Participating Generator Agreement (PGA) to offer all of their capacity to the ISO in real time

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Purchase Contract Efforts," March 20, 2001.

for declared forced outages, the unit owner can avoid this obligation by simply declaring a forced outage. The discussion of the selling obligation appears to give this exemption for declared forced outages by stating that, "Sellers will PGAs should be required to offer all their capacity to the ISO in real time if it is available and not scheduled to run."

Second, the Staff's plan also does not prevent generation unit owners from engaging in what has been called "megawatt laundering" as a way to receive a higher price for their energy than a price cap or a cost-based bid cap. Although, the Staff's proposed plan appears to reduce the incentive a unit owner has to declare sufficient capacity forced out to cause a Stage 3 emergency, this logic ignores the fact that an in-state generator always has the option to sell all of its available capacity outside of California on a day-ahead basis. One would expect the firm to do this in advance of the days its suspects Stage 3 emergencies will occur. On these days, the firm will find many buyers located outside of California who are willing to pay very high prices on a day-ahead basis because these buyers are confident they sell this power back into California at very high price during the Stage 3 conditions the following day. Consequently, under the Staff's proposal, on a high demand day a generator could schedule the much of its capacity outside of California on a day-ahead basis and declare and declare much of the remaining capacity forced out. This might cause a Stage 3 emergency, but because the generator has no unused available to capacity to sell in the ISO's real-time market, it is indifferent as to whether its bids into the ISO's real-time energy market are mitigated. In addition, the entity outside of California that purchased the firm's power on a day-ahead basis would be very likely to refuse to sell into California unless it received a sufficiently high price energy in the ISO's real-time market. This logic illustrates that the Staff's plan does not address the much publicized problem

[4] Wolak, Frank A. and Patrick, Robert H. (1996) "The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market," (available from

of "megawatt laundering" to circumvent the real-time bid caps. This occurs when the same power is sold outside the state in the forward market and then sold back into the state at a significantly higher price in the ISO's real-time market.

The Staff's proposal also does not address the two fundamental tenets of market power mitigation. First, market power mitigation must alter the incentives that market participants have to increase spot prices, or equivalently exercise market power, through their bidding behavior. Second, market power mitigation must reduce the amount that consumers pay for wholesale electricity significantly below the amount they would pay in the absence of market power mitigation. Although a successful market power mitigation plan should achieve both of these goals, at minimum market power mitigation should achieve the second goal. Because the amount the consumers pay equals the amount that producers receive for the energy they supply, market power mitigation necessarily implies that producers receive less for the energy they supply than they would in the absence of market power mitigation. As noted above, because the Staff's proposed plan only calls for imposing mitigation measures during Stage 3 system emergencies, the vast majority of hours when market power is exercised in the California electricity market will be unmitigated. In addition, because the Staff's plan cannot solve the non-verifiable forced outage problem and does not address the "megawatt laundering" problem, it is unlikely the Staff's proposal will lead to significant market power mitigation during Stage 3 emergencies.

Because market power mitigation requires reducing wholesale energy and ancillary services prices and reducing the revenues generators would earn in the absence of mitigation for supplying the same amount of energy and ancillary services, regulatory intervention is required.

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http://www.stanford.edu/~wolak) discusses this issue for the England and Wales market.

A profit-maximizing firm will not voluntarily give up any market power that it might have. The belief that generation unit owners serving the California market would voluntarily enter into forward contracts with load-serving entities in California at prices that do not fully reflect the market power these firms possess, reflects a fundamental misunderstanding of this logic. No profit-maximizing firm would voluntarily enter into a forward contract for the next two years or for any other time horizon at a price that does not yield the firm greater expected profits than it could earn from selling its output in the California spot market or any other spot or forward geographic market over that time horizon.

A successful market power mitigation plan must necessarily be imposed upon the market participant whose market power is being mitigated, because the plan must guarantee a reduction in the amount California consumers pay to this entity for wholesale energy and ancillary services. In the aggregate, this implies that generation unit owners supplying energy and ancillary services to California will therefore receive lower revenues from California consumers. These reduced revenues collected from California consumers and received by generation unit owners do not necessarily imply that profits to these generators must be reduced. This is because one of the ways that firms attempt to exercise market power is by deviating from the least-cost mode of production in order to increase market prices and obtain higher profits.

A market power mitigation plan that also achieves the first goal is very likely to cause the generator unit owner to produce its output in a more least-cost manner, which could result in a higher level of profits for the firm despite the fact that it is collecting less revenues from consumers. For example, the mandatory forward contracting solution we propose does just that because it provides the firm with a very strong incentives to supply at least its forward contract commitment of energy to the spot market at a low price in all hours. Unless a market power mitigation plan achieves these two goals, it is not protecting consumers from the exercise of market power. The most effective market power mitigation plan is the one that accomplishes this goal of with the least amount of distortions to the spot electricity market.

Recommended Market Power Mitigation Plan

Because it achieves the two major goals market power mitigation without interfering with the operation of California's spot electricity market, we continue to advocate for the market power mitigation plan outlined in the December 1, 2000 MSC report and elaborated on in greater detail in the February 6, 2001 MSC report which is attached to the end of this report. This plan will provide guaranteed market power mitigation to California consumers. It will also send the strongest possible signals for final electricity demand in California to become price-responsive and for existing suppliers to sell into the California spot market over the next two years.

The major features of this plan are the mandatory forward contracts on all California market participants at just and reasonable rates, the assumption of all forced outage risk by generation unit owners, the removal of all price caps on the spot electricity market, and a small real-time trading charge on all purchases and sales from the ISO's real-time energy market by generation units and loads. The details of this proposal are described in the February 6, 2001 and December 1, 2001 MSC Reports.

In its discussion of the MSC proposal, the Commission's Staff report indicated it was disinclined to recommend setting a just and reasonable price for these forward contracts. Moreover, the Staff Report suggested that these forward contracts be voluntary. As should be clear from the above discussion profit-maximizing firms do not give away their market power voluntarily without being paid for its expected value. Given this fact, voluntary forward contracts for the supply of energy over the next two years cannot mitigate market power, because California consumers must pay at least as much as they would pay in the absence of this voluntary market power mitigation. The presence of a number of new entrants willing to supply electricity to California from new facilities built in the State and coming on line more than two years from now disciplines the exercise of market power for forward contracts to supply electricity more than two years from now. The relatively small amount of forward contract cover obtained by the California Department of Water Resources (CDWR) for the summer of 2001 and the entire year of 2002 versus more than two years in the future when there is likely to a significant amount of new capacity on-line in California, provides concrete evidence for this point of view. Clearly, the California negotiators had very strong incentive to purchase as much forward contract cover as they could for the next two years. However, because the generation unit owners are aware of the significant market power they possess for the next two years (before this significant quantity of new capacity comes on line), they are unwillingness to sign forward contracts for the next two years at a price at all close to the benchmark just and reasonable price given in the February 6, 2001 MSC report. Since that report was filed, New York Mercantile Exchange (NYMEX) natural gas futures prices at Henry Hub have fallen further, which implies that a lower benchmark of just and reasonable rates would be computed using the methodology outlined in the December 1, 2000 MSC report.

One way for the Commission to avoid having to set a just and reasonable rate for forward contracts is to make the alternative to entering into the required amount of forward contracts for the next two years with a California load-serving entity sufficient unattractive to all California market participants. The Commission would not specify the terms or conditions of forward contracts between the California market participants and California load-serving entities.

Instead, the Commission would subject these contract negotiations to the backstop that if a sufficient quantity of forward contracts are not signed by April 15, 2001 between a given market participant and the California Department of Water Resources or other California load-serving entities, then all of the sales by that market participant would be subject to full cost of service rates. This default option of cost-of-service sales if a voluntary forward contract is not entered into could serve as a rough substitute for imposing a fixed quantity of forward contracts at a pre-determined just and reasonable rate. In this case, the market participants know that by failing to sign the required forward contract quantity for the next two years, they will only be able to recover their cost-of-service-regulated rates for all of their sales over this time period. Clearly, given the current conditions in the western US electricity market, all market participants would prefer to be able to sell at least a fraction of their capacity at the spot price as opposed to being subject to cost-of-service rates for all of their sales. Therefore, the desired forward contracting outcome would be achieved at some negotiated price which reflects each California market participant's assessment of its average revenues from cost-of-services sales for the next two years.

Many commentators have suggested the need for a regional solution to the very high electricity spot prices likely to exist for the next two years in the western U.S. While we support such a regional solution to this problem, our plan does provide significant region-wide relief. However, as noted earlier, the entire WSCC is a single integrated market and spot prices inside of California are likely to closely track spot prices outside of California. Consequently, we expect that our recommended market power mitigation plan will produce lower average spot prices in California over the next two years because California market participants have a stronger incentive to bid aggressively into the California electricity market due to their forward contract obligations with California load-serving entities (or simply with the California Department of Water Resources) for a substantial fraction of their expected sales into California over the next two years at the just and reasonable competitive benchmark price outlined in the December 1, 2000 and February 6, 2001 MSC reports. This more aggressive bidding in the California market will result in lower average spot prices in the remainder of the WSCC and in that sense provide a regional, market-based solution to this regional problem. It is important to emphasize that we believe that the solution we advocate does not require other states in the WSCC to pay higher spot prices in order to reduce spot prices in California. In fact, we anticipate that even with the market power mitigation plan that we advocate in place, California will still be required to purchase approximately 15% of it energy needs from the spot market over the next two years. This fraction of spot market purchases is significantly higher than the fraction of spot market purchases any of the remaining states in the WSCC should have to make from the spot market over the next two years. Consequently, our market power mitigation plan leaves a significant amount of the spot market price in the WSCC to managed by California loads over the next two years. However, it does allow all WSCC loads to benefit from the lower spot prices in California and the rest of the WSCC likely to occur as result of mandating forward contracts at just and reasonable rates from all California market participants for 75% of their expected sales into California for the next two years.

Price Responsive Demand to Mitigate Market Power

We wish to reiterate a point made in a number of our previous opinions–price responsive retail demand is essential to constraining generator market power. Right now, that condition does not exist because of the retail rate freeze. As part of the State's restructuring of the California market, if it hopes to retain some form of market system, the State must reflect wholesale energy costs in the prices that consumers pay and allow consumers during periods of high demand to lower their electricity costs by lowering consumption. For this reason, we continue to recommend the immediate imposition of real-time pricing for all large industrial and commercial customers. We also recommend the widespread implementation of real-time metering technology for California's residential customers as soon as possible.

We should also emphasize that real-time pricing does not necessarily require that consumers pay higher electricity bills this summer. If they are sufficiently price-responsive they could in fact reduce their monthly electricity bill. For example, consider the following two period example. Suppose that the price in period 1 is \$100/MWh and the price in period 2 is \$10/MWh. Suppose the consumer is on a fixed price retail rate of \$20/MWh and consumes 1 MWh, allocated equally across the two periods. Consequently, the cost of this energy is currently \$55 = ½*\$100 + ½*\$10. The consumer pays \$20 so that the State must pay \$35 = \$55 - \$20, because it is purchasing power at a wholesale price greater than the current retail price. Assume for simplicity that transmission and distribution prices are zero. Suppose the customer is capable of shifting ¼ of his consumption from period 1 to period 2. With this consumption pattern, his total bill is \$32.50 = ¼*\$25 + ¾*\$10. Suppose that the state now decides to pay this consumer to take on real-time price risk \$15. This switch to real-time pricing has reduced the amount of money California taxpayers have to pay to this consumer from \$35 to \$15 and this consumer's price-responsiveness efforts has decreased his monthly electricity bill from \$20 to \$17.50. Both California taxpayers and California ratepayers benefit from the mandatory imposition of real-time pricing. These benefits accrue because the consumer sees the real-time price signal and can benefit in terms of reductions in his monthly bill at the real-time price per MWh not consumed during the high priced period.

The widespread adoption of significant real-time pricing will also make negotiating forward financial contracts on a voluntary basis somewhat easier. Generators will realize that with a significant fraction of the large demanders able to see and respond to real-time spot prices, average prices in the spot market for the next two years should be lower than they would in the absence of the widespread adoption of real-time pricing. The lower spot prices that will result from a significant commitment by the State to real-time pricing will create a lower opportunity cost to a generator to signing a forward contract of the next two years. Consequently, generators should be more likely to sign forward contracts for the next two years at lower prices than they would in the absence of a large commitment by the State to real-time pricing.

We should emphasize that time-of-use pricing, where a fixed pattern of retail prices, independent of current wholesale prices is offered to consumers does not provide the benefits that real-time pricing does. For example, usually the day is divided into peak and off-peak periods with the price in peak periods four to five times higher than the price in off-peak periods. Although the use of time-of-use pricing may create strong incentives to consume less energy during the peak-period of the day, time-of-use pricing does not provide any incentive for loads to reduce their consumption during periods when wholesale electricity prices are high. Consequently, in terms of its ability to mitigate market power, time-of-use pricing is virtually equivalent to a single fixed real-rate. Time-of-use pricing is simply several fixed retail rates for the peak and off-peak periods. Consequently, raising the single fixed retail rate paid by a consumer would accomplish close to the same demand reduction as putting that customer on time-of-use rate. However, what real-time pricing does is ask the customer to shift their consumption across hours of the day depending on the hourly prices that day to reduce their electricity purchase costs. Similar to the case of load-profile billing, a customer on a time-of-use pricing plan receives the same reduction in their monthly bill from reducing their demand by 1 kwh during a peak hour when the wholesale energy price is $5000/MWh as he does from this same demand reduction during a peak hour when the wholesale energy price is $10/MWh. However, a customer on a real-time pricing plan receives a 500 time greater financial benefit from reducing his consumption by 1 kwh during the peak hour with a price of $5000/MWh as he does during the peak hour with a price of $10/MWh.

The need for real-time price-responsiveness is reinforced by the practical requirement to find a means short of rolling blackouts to constrain consumer demand this summer. California demand/supply projections for this summer indicate a significant likelihood that demand will exceed available supply for a number of hours this summer, even if issues relating to paying generators for ongoing sales into the California market are resolved. We believe that California consumers need strong and effective price signals where a failure to decrease consumption will result in sharply increased electric bills. Without that signal, it will be impossible to avoid massive power shortages throughout the State.

Conclusion

The conditions in the California electricity market are such that without regulatory intervention by the Commission, California is likely to face both many hours of rolling blackouts this summer and the prospect of paying energy and ancillary services prices during the summer of 2001 that reflect the exercise of significant market power. California is facing a crisis that it cannot unilaterally solve without significant damage to the health of its economy. Intervention of the form recommended in the February 6, 2001 MSC report will still leave California paying extremely high spot prices for electricity for a non-trivial fraction of its load for the next two years. However, by significantly reducing the amount of energy California must purchase on this spot market at these extremely high prices, the Commission can leave with a problem that it has the financial ability to solve, rather than one that has a good chance of simply overwhelming it. Equally important, market power mitigation of this form will preserve a working spot electricity market to provide the necessary price signals to attract much needed supply to California this summer and provide the real-time price signal necessary to reduce demand during high-priced periods.