

6. Policy Options

This section discusses some of the options available to the Commission or state agencies, with encouragement by the Commission, to correct the conditions that led to the unusually high and volatile prices in the West during the summer of 2000. Those conditions were: a general shortage of generation throughout the West, an over-reliance on spot market purchases by the IOUs in California, insufficient demand responsiveness to price, and a highly politicized process for setting price caps for the Cal-ISO. The options are summarized below first and then discussed in the following section.

To encourage investment in new generation:

- ! Adopt policies that encourage and facilitate the investment in new generation. Tight generation resources were a major factor contributing to high prices. Easing local siting approval processes in California could encourage more investment and ultimately bring on more electricity supply. At the federal level, the Commission's wholesale price policies have an important effect on investment decisions and should be designed to create incentives to spur new investment in generation and transmission.

To remedy the over-reliance on spot market purchases:

- ! Eliminate the requirement that the three California IOUs must buy and sell through the PX. This can be implemented by the Commission (1) requiring a change in the eligibility provisions of the PX tariff or (2) changing its policies applicable to wholesale spot markets.
- ! Require the IOUs to hedge and forward contract through the PX and bilateral transactions. This can be implemented either by the CPUC or by the FERC.
- ! Require all in-California thermal generation capacity to be bid into the forward California markets. This option might increase the amount of capacity available in the forward markets.

To provide more demand response to wholesale prices:

- ! Encourage California to implement policies to increase retail demand responsiveness to price. The Commission has no authority over retail rates in California; however, California may undertake retail market reforms that will greatly benefit wholesale markets. Competition among energy service providers for the retail load of the IOUs would create strong downward pressure on the price of energy in California. Just allowing large retail consumers to face the price in the wholesale market would provide more demand responsiveness to the wholesale market. If state policy is to allow load serving entities to pass through the costs of energy and ancillary services directly to

retail customers, then those customers should be given some way to respond to those prices. If state policy continues to regulate retail service by the IOUs, then the IOUs should be given strong incentives to minimize their wholesale purchase costs.

- ! The Commission can stimulate greater demand response for the wholesale market by requiring the California ISO to allow scheduling coordinators to bid load responses in the ancillary services market (reserves, etc.). Scheduling coordinators could receive bids from those willing to provide a load reduction and then bid those in the ancillary services market. The scheduling coordinators could arrange with the ISO, on a bilateral basis, terms such as price and performance measures.

To provide some price regulation while generation resources remain scarce and until regulatory changes are made to provide more demand response:

- ! The Commission could return to traditional cost-of-service regulation for generators in California. There is the potential that this option could result in relatively high rates if the acquisition premiums of the non-utility owners are taken into account. Also, this alternative may be inconsistent with an objective to encourage investment in new generation.
- ! The Commission could adopt limited term price caps for spot market sales (day-ahead and hour-ahead) in both the PX and the Cal-ISO. The price caps would apply for a fixed 18-month period, the period in which generation is currently predicted to remain scarce, and would allow time to develop a regulatory structure to provide greater demand response. The cap would be set at a level that would permit recovery of current marginal costs, including opportunity costs, and be high enough to encourage new investment. An alternative would be to apply this limited-term price cap to all short-term wholesale sales in the West.
- ! Alternatively, the Commission could adopt a limited-term price cap to apply to long-term sales in addition to spot market sales. Since wholesale forward prices in California are also high, as a result of conditions last summer, the Commission could also adopt a temporary price cap to apply to long-term sales, to allow time for new generation to enter the market and for the regulatory structure to permit greater demand response. This option could have the effect of discouraging new investment, particularly if investors rely on forward prices to signal the need for new investment.
- ! As an alternative to a price cap on long-term prices, the Commission could adopt target prices for long-term contracts in the California market, based on pre-summer prices. These would apply for an 18-month period as described in the price cap options above. Wholesale sellers that substantially exceed the target prices would be subject to

close scrutiny to determine whether they are exercising market power, with a potential loss of their market-based rate authority.

- ! The Commission can leave the spot market and long-term market prices unconstrained. With the evidence of scarcity in the region, higher prices produced by the market may be the right stimulus to needed new investment. This option would be more effective if coupled with actions to improve the overall functioning of the market, such as improving demand responsiveness and minimizing the reliance on spot market purchases. The option can be coupled with increased monitoring of market participants for evidence of market power abuse.
- ! The Commission can implement locational market power mitigation measures, independent of the options for price caps.
- ! The Commission could change the auction rules used by the PX and the Cal-ISO to pay sellers what they bid rather than the market-clearing price. This option can be adopted independent of other pricing options.

To create a more stable regulatory environment:

- ! The Commission can abolish the current stakeholder governing boards of the Cal-ISO and the PX and require independent, non-stakeholder boards. This would also eliminate the need for the EOB, which could be abolished also.
- ! The Commission can retain the sole authority to impose price caps in wholesale market transactions and not delegate that authority to the Cal-ISO or the PX.
- ! Require the Cal-ISO and PX market monitors to report directly to the FERC any evidence of market power abuse for evaluation and action by the Commission, without prior review by their boards.

Other options:

- ! To eliminate underscheduling in the Cal-ISO, the Commission can change the incentives for suppliers to sell in real-time and require stronger penalties for real-time purchases, combined with increased options for IOUs to have broader supply portfolios.
- ! The Commission could direct a further investigation of generators with abnormally high unplanned outage rates or bidders into the PX to examine whether individual market participants may have engaged in withholding or price manipulation. This option could be coupled with increased reporting to the Commission, as discussed in other options.

Discussion of Options

1. Encourage Investment in New Generation

Most projections for new generation capacity additions indicate that a significant amount of new capacity is planned to be available in 2002. Until new generation is added in the West, high prices can be expected to recur. While high prices are necessary to stimulate investment in new generation, barriers to the entry of new supplies into the market will result in a longer period of high prices than may be necessary. Federal, state and local regulatory policies should be designed to eliminate unnecessary barriers to new generation and to create incentives for new investment.

Specific rules about siting and local approval processes are within the control of state and local policymakers. Some steps have been taken in California to speed the local approval, but there may be more things that can be done.

At the federal level, Commission pricing policies can have an important impact on investment decisions. If wholesale prices are kept too low through regulatory controls, this can cause investors to invest in other markets. For example, if the Commission imposes wholesale price caps in California that are too low, generators may choose to build in Arizona or Nevada where there would be no price caps but where there is a growing demand for power. To provide an incentive for new generation to be located in California as well as other western states, the Commission may need to explicitly take into account the need to stimulate new investment through pricing policies.

Another factor that affects investment decisions is the stability of the regulatory process. To finance new generation plants, firms need to be able to convince their investors that the regulatory environment is stable enough to assure a return over the life of the project. This past summer's experience with the constantly changing Cal-ISO price caps created instability for the market and aroused investor concerns about investing resources in California. Therefore, stability in pricing policies can be a factor in encouraging investment in new generation.

2. Remedy the Over-Reliance on Spot Market Purchases

Spot markets are inherently volatile. In eastern bulk power markets with an ISO only 10 to 20 percent of the load is served by spot market purchases, but in California almost 100 percent of the load served by the IOUs is served by purchases in the spot market. Shifting purchases out of the spot market to longer term contractual arrangements would create greater price stability for wholesale buyers and end-users. In this market context, day-ahead and day-of purchases are spot market purchases. Forward contracts, for purchases longer than day-ahead and day-of, are longer term contracts.

Forward contracts for energy potentially can provide IOUs and other load serving entities with a highly effective hedge against high costs in energy spot markets, while providing both buyers and sellers with a greater level of price certainty. If generators are otherwise able to exercise market power in energy spot markets, such contracts can help to mitigate the market power of the generators that contract to sell their output at a fixed price. Thus, forward financial contracts offer the potential to reduce both the cost impact of price spikes on consumers' bills, and the incidence and magnitude of the price spikes that occur.

There are several options available to shift purchases to forward contracting:

Eliminate the requirement for the three California IOUs to buy and sell through the PX. During the summer of 2000 the IOUs had limited authority to enter into forward contracts. The block-forward contract available to them through the PX is insufficiently flexible to provide them the full benefits of forward contracting. Eliminating the restrictions on their ability to forward contract and to purchase supplies outside the PX would provide them with the ability to create portfolios of supply contracts to get more stable energy costs. While the CPUC recently expanded the authority of the IOUs to enter into bilateral, long-term contracts, this authority is still limited.

These restrictions could be eliminated directly by the Commission through actions it could take within its wholesale jurisdiction. When the Commission originally approved the restructuring proposals of the IOUs, it found that any concerns it might have about the requirement at that time were outweighed by other considerations.¹ The Commission could now find that such restrictions have become an impediment to the stability and proper functioning of the wholesale market and require a change in the eligibility provisions of the PX to insure that any wholesale buyers in the PX have the ability to buy their supply from other sources, or could otherwise establish a similar condition as a prerequisite to the IOUs transacting business in the wholesale market.

One of the original reasons for the mandatory buy/sell requirement was a concern for potential affiliate abuse in the buying and selling of energy. There are other ways to deal with this concern. For example, the IOUs could be required to use most-favored nations clauses for any transactions with affiliates to ensure that the price agreed to in an affiliate deal is no higher than the prices paid to non-affiliates.

Require the IOUs to hedge and forward contract. This is a variant of the option discussed above. The difference is that, rather than just eliminating an impediment to hedging and forward contracting, the option goes a step further to require the use of these tools. This could be done as a requirement to purchase a certain percentage of a supply portfolio through different instruments, and it could be implemented either by the CPUC or the Commission in the same way as the option above. It has the disadvantage of substituting the judgment of regulators for the judgment of business

¹Pacific Gas & Electric Co. et al., 77 FERC ¶61,265 at 62,088 (1996).

managers as to the best way to create a balanced supply portfolio. Providing business managers with financial incentives for managing their business in a way that minimizes costs is usually a more effective regulatory strategy.

Require all in-California thermal generation capacity to bid into the California forward markets. This option is the flip-side of the option above. It may increase the amount of capacity made available in the forward markets and it would allow generators to arrange sales in the forward markets at whatever prices they can negotiate. Thus, forward market sales would be market based, and generators would be free to pursue their most profitable opportunities.² However, as an incentive to get the maximum amount of thermal capacity available in the forward markets, thermal generators would be required to submit bids at the generator's marginal operating cost in the ISO's real time market for any unsold capacity.³ Enforcing such a requirement would prevent generators from withholding capacity from the market, so prices in the real time market would not be inflated due to the exercise of market power. In addition, suppliers would have less ability to exercise market power in the forward markets, because buyers could avoid inflated forward market prices by buying in the real-time market.

A requirement to bid at marginal operating cost does not take into account a generator's opportunity cost, which may exceed its marginal operating cost when other markets are transacting at higher prices. But while thermal generators may have opportunities to sell in multiple markets in advance of real time, those opportunities fade as real time approaches. By the time the real-time market is operating, a thermal generator has no opportunity to sell elsewhere if its bid is rejected, so it has no opportunity costs.

This requirement is an option for most thermal generators, but not for hydro generators or for other generators with an absolute limit on the amount of energy that they can produce. That is because these latter generators may face opportunity costs in real time, because production in one hour may reduce the amount of production that can occur in subsequent hours. For example, hydro generators often have a limited supply of their energy source (water), so producing electricity in one hour reduces the amount of water available to generate electricity in a subsequent hour. Thus, by producing electricity in one hour, a hydro generator foregoes the opportunity to receive revenue in a subsequent hour. By contrast, most thermal generators do not face a limited supply of their energy sources, so

²Forward market sales in this context could also include purely financial hedges, such as “contracts for differences,” where a buyer and seller agree in advance to a contractually-specified price (called a “strike price”) for a specified quantity. Then, after the real time market closes, the buyer and seller agree to make additional payments to each other based on the difference between the real time spot price and the strike price.

³In addition, regulatory must run and must take generators would continue to be required to bid into the PX energy market at \$0, as they are currently required to do.

producing electricity in one hour does not reduce the amount of electricity that can be produced in subsequent hours. However, certain thermal generators may face absolute limits on the amount of energy that they can produce or on the amount of time that they are permitted to generate, for example, due to environmental regulations. Since California has a significant amount of old thermal generators subject to emissions limitations, this may not be an attractive option.

Another criticism of requiring generators to bid previously uncommitted capacity into the real-time market is that it may encourage too much reliance on the real time market and too little scheduling in the forward markets, and thus may create operational and reliability problems for the ISO. If over-reliance on the real time market creates undue operational problems, the option could be modified to require generators to bid into the PX's day-of energy market (rather than the real time market) at marginal operating costs. This option would still give generators the opportunity to arrange sales in other forward markets at advantageous prices before the Day-of market closed, although it would reduce slightly the time available to do so.

There are several options for establishing when the bidding requirement could be triggered. One option is to impose the requirement on all generators at all times. This option might be chosen if market power arises frequently, or if it is difficult for the ISO to predict in advance when market power will arise. Alternatively, if the ISO can accurately forecast when and where market power is likely to arise, the bidding requirement could be imposed in more limited circumstances. For example, if market power arises only during high demand periods, the bidding requirement could be imposed only when the ISO forecasts load in an hour to exceed a specified level. Or, the bidding requirement could be imposed on generators in defined areas when transmission constraints arise that create locational market power.

By differentiating between generators within California and generators outside California, this option can have the effect of balkanizing the wholesale market and discouraging new investment in generation in California. Also, it may be difficult to administer and enforce.

3. Provide More Demand Response to Wholesale Prices

Encourage California to implement policies to increase retail demand responsiveness to price. There are retail market reforms that California can take that would greatly benefit the wholesale market by creating more demand responsiveness.

In well functioning competitive markets, both suppliers and consumers are able to see and respond to market prices. Indeed, this is what allows competitive markets to achieve the efficient outcomes for which they are well noted. However, in electricity markets, such as those in California, consumers often must make their consumption decisions without knowledge of the true market price of electricity. Currently, most California consumers (those served by PG&E and Southern California Edison) do not face wholesale electricity prices because of a retail rate freeze. The resulting lack of

demand responsiveness to wholesale prices can, at times, lead to excessively high wholesale prices. When supply is scarce relative to demand, competitive prices will rise to a level that reflects the value that the marginal consumer places on additional consumption. This additional increment above marginal running cost is referred to as the “scarcity rent.” However, market prices in electricity markets like those in California cannot be expected to settle at this level if consumers do not have the ability to see these prices and to make known to the market, through their purchasing decisions, the value that they place on marginal consumption. Indeed, in the absence of demand responsiveness, prices in California and in markets elsewhere frequently rise well above this competitive level at times when demand is high and capacity is scarce.

One way to allow retail consumers to respond to wholesale prices is for retail rates to reflect wholesale prices. However, to ensure that retail consumers can respond effectively to wholesale prices, they should have some advance notice of the change in retail rate policy, so that they can prepare for the new retail rate design. In the meantime, their traditional service providers should face incentives to procure electricity for their customers at least cost. California policymakers could also increase demand responsiveness to wholesale electricity prices by encouraging greater retail competition.

California should consider, in the long term, reevaluating the status of IOUs as providers of both distribution and energy services to their retail load. While California formally permits retail customers to choose among alternative suppliers, in practice few new retail energy service providers have entered the market thus far. Greater competition among energy service providers for the retail load of the IOUs would create a strong downward pressure on the cost of energy in California. Promoting greater retail competition likely would require a formal separation of the IOU distribution service functions from any continuing role as an energy service provider. In addition, consideration may have to be given to changing the CTC recovery mechanism and to imposing a provider-of-last-resort obligation on the IOU. Also, consideration should be given to providing large retail consumers of IOUs, the traditional retail service providers, with real-time price signals that would allow them to respond to the wholesale prices.

As long as California regulates retail service provided by IOUs, then the IOUs should be given strong incentives to minimize their wholesale costs. Regulations should be avoided that allow load serving entities to pass through the costs of energy and ancillary services directly to retail customers without giving those customers the ability to respond.

The Commission can stimulate more demand response for the wholesale market by requiring the Cal-ISO to allow scheduling coordinators to bid load responses in the ancillary services market. To implement this option, scheduling coordinators could receive bids from any user willing to provide a load reduction. The scheduling coordinators could arrange with the ISO, on a bilateral basis, the terms such as price and performance measures. This would not obviate the need of the CPUC to design demand response mechanisms for the retail market, but it is an option available to the Commission independent of the retail regulation.

4. Provide Some Price Regulation While Generation Resources Remain Scarce and until Regulatory Changes Are Made to Provide Greater Demand Response

The Commission could return to traditional cost-of-service regulation for generators in California. Traditional cost-of-service regulation is used when the market cannot be relied on to keep prices within a reasonable range because the regulated company exercises monopoly power. Under traditional cost-of-service ratemaking, a company is allowed to recover its prudently incurred fixed and variable costs plus its cost of capital including a reasonable return on its investment. Fixed and variable costs include operation and maintenance expenses (including fuel and emission allowances), depreciation, and taxes. The return on investment is calculated by multiplying the rate of return times the jurisdictional public utility's rate base. Rate base is calculated by subtracting from gross plant in service any accumulated reserve for depreciation associated with that plant and adding or subtracting from the net plant value any adjustments to rate base (such as accumulated deferred income taxes).

Prior to the divestiture of generating assets in California, jurisdictional utilities recorded these expenses consistent with the Commission's Uniform System of Accounts and annually filed a FERC Form 1 detailing their operating expenses including specific generating plant data in accordance with the Uniform System of Accounts. However, the new owners of the divested generating units are no longer required to follow the Commission's Uniform System of Accounts; nor are they required to file with the Commission a FERC Form 1. Therefore, the data needed to calculate a traditional cost-of-service rate is not currently collected and would have to be acquired. Determining a cost-based rate for every generation owner in California would involve numerous filings dealing with complex cost-of-service issues such as the appropriate depreciation rate for the unit, how income taxes would be calculated, capital structure, and the appropriate rate of return.⁴ In addition, these cost-of-service issues may deal with issues of first impression because the new owners of each unit are, in many instances, limited liability corporations or partnerships. This is likely to be a complicated, time-consuming, administrative process.

The new generation owners purchased the divested generating assets of the IOUs for a premium over their net book value. In the past, the Commission has permitted the inclusion of acquisition adjustments in rate base for wholesale rates only if a utility can show that the investment decision is prudent and if it can demonstrate that the acquisition provides measurable benefits to ratepayers.⁵ The Commission would need to address the prudence and benefits of these acquisition

⁴The volume would increase substantially if cost-based rates were applied to generation owners outside of California (the entire WSCC) for their sales into the California market.

⁵See Minnesota Power & Light Company and Northern States Power Company, 43 FERC ¶ 61,104 at 61,342 (1988).

adjustments. If the Commission recognizes this premium in setting the new cost-based rates, the rates for these assets would be substantially higher than when the IOUs held the same assets prior to divestiture.

An alternative to including the full amount of the acquisition premium in the cost-of-service rates would be to exclude the acquisition premium from rates or offset the total acquisition premium by the amount that the generator made in the market (either this summer or since the transfer took place) over what it would have made under competitive circumstances. Either option would depress the value of the companies that purchased the generation assets and could present disincentives to future purchases of divested utility assets as part of retail access in other parts of the country.

Finally, if the Commission were to impose cost-of service rates for all wholesale sales in the California market, the Commission would also need to calculate cost-of-service rates for any remaining wholesale sales made by the three IOUs. The premiums received by the IOUs for their divested assets were used as an offset to their stranded costs. Any determination of a cost-of-service rate for the IOUs would need to take into account the total acquisition premium that was received by the IOUs to pay down the value of their stranded assets. The new cost-of-service rates for these assets should be lower than under the old regulated structure; however, whether the decrease in rates for these assets would offset the higher rates for the divested assets could only be determined after the Commission has had the opportunity to analyze all of the cost-of service rates for generation owners within California.

Traditional cost-of-service regulation is a reasonable option where the regulated firm exercises substantial market power, such as a natural monopoly, but is ill-suited to markets where firms have market power but also face some competition. Traditional cost-of-service regulation does not allow the firm the flexibility to respond to market signals, for example to lower prices, and still earn its allowed reasonable return because it cannot raise prices enough at other periods to compensate for the lower price periods. In those cases, other forms of price regulation are better suited. In the West, Commission regulated generators face competition from public power and power marketers, so traditional cost-of-service regulation may not be appropriate. In addition, traditional cost of service regulation is an administratively costly method of regulation because it is resource intensive, both for the regulatory agency and for the regulated firm. It can add significant transaction costs to an industry that may not be commensurate with the amount of protection it would provide in a particular context. Finally, a return to cost-of-service rates, even for an interim period, would create regulatory uncertainty that would likely exacerbate existing supply problems within California, and would have an adverse rippling effect in other electric markets in the country.

The Commission could adopt limited term price caps for spot market sales (day ahead and day of) in both the PX and the Cal-ISO. To give some protection from high prices until new generation plants are expected to come on line in 2002, and to provide time for the development of regulatory changes to stimulate greater demand response and thus better price signals for the wholesale market, the Commission could impose price caps on the spot market in California.

To provide certainty for the market the cap should be imposed for a limited, fixed duration and, if the level of the cap changes, the changes should occur in predictable ways.

In addition to certainty and predictability, there are some other factors to be taken into account in setting a price cap. Ideally a price cap should be high enough to attract generation investment to the market, but low enough to provide protection to consumers during the short-term. It should be high enough to permit the recovery of current marginal running costs and opportunity costs and provide a stimulant to new investment. Another consideration is that the price cap on the spot market should be high enough to provide an incentive for buyers to enter into long-term contracts. It also should apply equally to all sellers in the market so, for example, sales in the PX would be capped at the same price as sales to the Cal-ISO.

The existing ISO buyers' cap appears to be too low. The current cost data show that at the end of the summer it started to come very close to the variable costs (fuel and emissions) of a combustion turbine. As the costs of generating electricity have gone up the price cap has gone down, narrowing the band of prices traded. A price cap at this level is unlikely to be high enough to stimulate new investment.

The Commission could set the price cap at the cost of entry into the California market. One difficulty with this choice is choosing the type of capacity that would enter the market. The cost of entry could be the cost of transmission expansion that would increase the import capability into California or it could be tied to the cost of a new generating unit. Since transmission capacity did not appear to be a significant constraining factor contributing to high prices in the West this summer, the cost of a new generating unit may be a more logical choice. The cost of a new generating unit could vary greatly depending upon whether the unit entering the California market is baseload, intermediate or peaking capacity.

Alternatively, the Commission could set the price cap using a formula tied to the marginal cost of the highest cost unit in the WSCC. This would provide a transparent price, reflect the actual cost of generation that could reach the California market, and would still be high enough to attract new, lower cost capacity to California. Determining the actual cost of this benchmark unit may be difficult, however, because it would require obtaining short run marginal cost data for all units in the WSCC to discover the highest cost unit, and then trying to determine the opportunity costs of this unit.

The Commission could choose to bifurcate the market and impose a price cap when load exceeds a specified level. Data supplied from the ISO indicate that the market deviates from normal operating conditions when load exceeds 35,000 MW. The Commission could impose a price cap when load exceeds this level. All price caps, unless set very high, have the effect of removing incentives for wholesale buyers to hedge against peak prices because the cap protects against high prices. However, this particular price cap option appears to highlight that effect since the price cap would become binding only at the time when scarcity becomes a serious factor. This could have a dampening

effect on the forward market and would not provide needed incentives for shifting purchases out of the spot market into the long-term market.

To provide certainty to the market, any price cap that the Commission chooses would need to be a hard cap that does not change during the transition period, or if it does change the changes should occur in predictable ways. The ISO changed its buyers' cap twice during the summer. These rapid changes in the ISO's buyers' cap created significant uncertainty for both power suppliers and buyers. This uncertainty increases the likelihood that suppliers will transact in more stable markets outside of California. In addition, it has been alleged that changes to the ISO's buyers' cap caused contractual problems for some participants in the California market that may have hedged at a price that was higher than that permitted under the most recent buyers' cap.

An alternative to a price cap for just the California market would be to apply the price cap to the entire WSCC.⁶ Applying price caps just to California could balkanize the western wholesale market and cause power to be exported from California to other states without a cap, causing continued shortages and high prices in California. On the other hand, it may be unnecessary to apply price caps to the entire WSCC since prices at other hubs in the WSCC were highly correlated with California prices. Thus, prices throughout the WSCC could be expected to track capped prices in California, even if the cap is not extended to the entire WSCC. A potential problem with applying a WSCC-wide price cap is that approximately 50 percent of the installed generating capacity in the WSCC is nonjurisdictional and would not be subject to the cap. Governmental entities sell their excess power in the wholesale market and, as was seen this last summer, the amounts sold can be significant.⁷ Thus the cap would be inapplicable to a large portion of the WSCC market and therefore could be ineffectual.

As previously noted, there are several potential levels for a price cap; however, whatever price cap is chosen, it should terminate at a predetermined time. Since the reasons for imposing a price cap would be to provide time for new generation to come on line and time for regulatory structures to be developed to provide a demand response, it would be reasonable to tie a price cap to a specified period needed for these changes. Significant new generation is currently planned to be on line in 2002, so an 18-month period would be reasonable. This should provide the time needed for California to site new generation as well as time to make necessary changes to its retail market structure to improve demand responsiveness. If California does not implement the reforms needed at the state level, the Commission should not extend the date. The market needs certainty and the high prices that result from scarcity should be felt by wholesale buyers and end-users so they can make rational choices about their

⁶A WSCC price cap of this type would only apply to transactions that are comparable to the PX and ISO markets, i.e., on day-ahead and hour-ahead trades.

⁷"Power Points: Winners in \$4 Billion Calif Sweepstakes," Dow Jones Energy Service (Sept. 29, 2000) (BPA, Salt River Project, LADWP and BC Hydro sold significant amounts of power.)

energy consumption. Californians are unlikely to be able to decide the relative values they place on environmental issues, public participation in governmental decision making, and electricity usage, or the value of obtaining supplies from the grid or from other sources, unless they know the cost of these choices.

Instead of a specified date, another option would be to terminate the price cap when the reserve level for the California market reaches a certain percentage. Under this option, a reasonable percentage could be established at a planning reserve number tied to the annual peak for the California market. Terminating the price cap when the specified reserve level is achieved should prompt generation expansion in California because the sooner generators increase their generation capacity the sooner the cap will be removed. This also provides certainty for investors that the rules are fixed and will not change. This may, however, diminish incentives for the state to expedite the siting of new generation.

Alternatively, the Commission could adopt a limited-term price cap to apply to long-term sales in addition to spot market sales. Since wholesale forward prices in California are high, as a result of conditions last summer, the Commission could also adopt a temporary price cap for long-term sales. The rationale for this cap would be the same as the spot market cap—to allow time for the entry of new generation and the development of regulatory mechanisms to provide a demand response. Even if the California IOUs are permitted, and/or encouraged, to develop balanced supply portfolios with more long-term supplies, buying long-term now may reduce the volatility of their supply costs, but it may not provide significant savings because current forward prices are high. Putting a cap on these forward prices would allow time for the market to recover from the summer prices that were unusually high because of a combination of factors. Choosing the correct level for this cap may be difficult. If investors rely on forward prices, more than spot prices, to signal the need for new investment, then finding the right long-term cap that will not discourage new investment may be a delicate task.

As an alternative to a price cap on long-term prices, the Commission could adopt target prices for long-term contracts in the California market, based on pre-summer prices. A less intrusive form of intervention would be to adopt some form of target price for forward contracts for an 18-month period. The target price, or prices, would be voluntary but any wholesale seller who sold too far above the target would be subject to investigation for the possibility of exercising market power. If the Commission determined that a seller was exercising market power, the Commission could rescind the market-based rates of the supplier.

One possible target price would be based on the May 1, 2000, price for a standard six by sixteen futures contract for July 2000 delivery at California's path 15 (either NP15 or SP15). The May 1, 2000, target price would have to be adjusted for any increase in natural gas prices and emissions allowance credits since that date. May 1, 2000, might be a reasonable date upon which to base a forward target price because the markets at that time were operating under relatively normal conditions

and prices for July 2000 delivery were consistent with prior periods, i.e., before market volatility appeared.

To implement this option the Commission may need to require monthly reporting of all individual forward contracts offered (both accepted and rejected) by suppliers to monitor their behavior during the transition period. The Commission could also encourage purchasers to report egregious offers by power suppliers.

This option could be combined with a requirement for generators to offer a particular amount of their supply in the forward market. However, there is no evidence that generators have been unwilling to commit to forward contracts and much anecdotal evidence that generators generally desire the financial stability provided by long-term contracts, at least for a portion of their supply. Therefore, this kind of requirement may be unnecessary, in addition to being intrusive in the market.

The option of a target price on long-term bilateral transactions, can be combined with a price cap on the spot market. Power suppliers with unsold generation from the bilateral market could have an incentive to drive up prices in the spot market during times of scarcity in order to maximize their revenue stream.

The Commission can leave the spot market and long-term market prices unconstrained. With the evidence of scarcity in the region, higher prices may be the correct market response to stimulate needed new investment. The high prices seen recently in the forward market may be the correct prices in light of the fact that shortages are likely to continue until 2002. Rather than trying to dampen those prices, it may be more beneficial to the market in the long run to leave those prices unconstrained. The experience in the Midwest after the price spikes in 1998 has been that significant generation resources were added to the region in response to those high prices. This option would be more effective if coupled with other actions to improve the overall functioning of the wholesale market, such as measures to provide a demand response and to minimize the reliance on spot market purchases. In addition, this option should be combined with increased monitoring of market participants to detect evidence of market power abuse, with any such conduct penalized if found.

The Commission can implement locational market power mitigation measures, independent of the other options for price caps. A single supplier may exercise locational market power because that supplier is the only option available to serve load in that area. The supplier may have several generating units at that location with more than enough supply available to meet demand; however, because of ownership concentration, the supplier can increase its price because of market power rather than scarcity of supply. The instances of market power may be isolated and infrequent, but this is an option available for mitigating the exercise of market power by a single supplier.

To mitigate the exercise of locational market power, the Commission could put in place resource specific bid caps. When a generator is called upon for a locational need, the unit would be paid either its bid cap if the market clearing price is lower, or the market clearing price if that price exceeds the bid cap. In no event would the generator set the market clearing price. The Commission could calculate the resource specific bid cap in several ways and let generator owners choose how they will be compensated. The resource bid cap could take several forms: (1) the Commission could require each generator to file the verifiable incremental operating cost which it would recover plus a margin for some recovery of fixed costs; (2) the resource bid cap could be equal to the market clearing price for similar hours and load levels when the unit's bid was in merit order with an adjustment for changes in fuel prices and emissions credits; or (3) the resource bid cap could be an estimate for running costs of a comparable unit. This option could be simplified to have one bid cap for each type of generating facility (e.g., stand-alone combustion turbines, combined cycle units, oil or natural gas-fired boilers).

This option is less intrusive than traditional cost-of-service regulation. It would be appropriate if there are significant barriers to new entrants and those barriers are unlikely to be removed. If new entry is possible, then an alternative would be to encourage other entrants into the market, and allowing the prices to be high is a way to attract new entrants.

The Commission could change the auction rules used by the PX and the Cal-ISO to pay sellers what they bid rather than the market-clearing price. Under this option the auction rules would be changed to pay each seller its bid, rather than the market-clearing price, and buyers would pay a price reflecting the average of the accepted sellers' bids. This might have the effect of lowering the total paid by buyers during high demand periods because some sellers would be paid less than the highest bid accepted. It may also change seller bidding behavior. Under this rule, sellers might submit higher bids than they might under a market-clearing price rule because under this rule the seller would only receive its bid, whereas under the market-clearing price rule, the seller would receive the market-clearing price even if the seller bid less. If generator bidding behavior changes in this way, it is not clear whether there would be much lowering of the total paid by buyers. Overall, it is not clear what effect this rule change might have on the total paid by particular consumers since consumers receive averaged monthly bills and not hourly bills.

5. Create a More Stable Regulatory Environment

The Commission can abolish the current stakeholder governing boards of the Cal-ISO and the PX and require independent boards, non-stakeholder boards. This would also eliminate the need for the EOB, which could be abolished also. The ISO and PX stakeholder board structures are designed to preclude dominance by one or two voting classes, but the stakeholder boards have difficulty coming to decisions on complex issues. These stakeholder governing boards are charged with making very difficult decisions that require satisfying a complex of

regulatory authorities, often under conflicting political and stakeholder pressures, while maintaining a fiduciary responsibility to the ISO and PX. The stakeholder boards are more susceptible to influence by the interests that they represent or by the direct or indirect pressures of others and are becoming widely perceived as too easily influenced by local political pressure.

As the Commission recognized in Order 2000, independence is the linchpin which should form the basic foundation of an RTO and it should apply to all structures, including an ISO.⁸ The Commission also reiterated that RTO governing boards have to satisfy the over-arching principle that their decisionmaking should be independent of market participants.⁹ Recognizing that the Cal-ISO is required to make its RTO filing by January 15, 2001, this may be the time to require a restructuring of the ISO board from a stakeholder board to an independent board, with similar changes to the board structure of the PX. Changing the structure of these boards could increase regulatory certainty in the California market and bring some stability to the market. Eliminating the stakeholder boards would eliminate the need for the Electricity Oversight Board. This would remove an additional source of local pressure on these federally regulated entities and clarify the regulatory oversight of the wholesale market.

The Commission can retain the sole authority to impose price caps in wholesale market transactions and not delegate that authority to the Cal-ISO or the PX. The repeated changes in the Cal-ISO price caps this past summer appeared to be the result of a highly politicized decisionmaking process. This can be corrected by changing the board structure of the Cal-ISO, but to provide more stability to the market, any wholesale price constraints that need to be imposed should be imposed by the Commission. Only the Commission has the broad regional perspective necessary to evaluate fully the value and impact of price caps on the market.

Require the Cal-ISO and PX market monitors to report directly to the FERC any evidence of market power abuse for evaluation and action by the Commission, without prior review by their boards. The Cal-ISO and PX each have well established market monitoring units and independent surveillance committees that monitor market behavior. The Commission could require these entities to report any allegations and evidence of market power abuse directly to the Commission. While these entities have the discretion to file their reports directly with the Commission,¹⁰ the current board structure may hinder the release of information that the Commission might find useful in its ongoing analysis of market behavior or that may be evidence of market power abuse that needs corrective action by the Commission.

⁸ Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Statutes and Regulations ¶ 31,089 at 31,046-48 (2000).

⁹Id.

¹⁰Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,122, slip op at 248-49.

6. Other Options

To eliminate underscheduling in the Cal-ISO, the Commission can change the incentives for suppliers to sell in real-time and can require stronger penalties for real time purchases, combined with increased options for IOUs to have broader supply portfolios. The underscheduling that has been experienced by the Cal-ISO causes reliability problems for the ISO, so remedying this would appear to be important. It appears to be an outgrowth of pricing policies that provide incentives for both sellers and purchasers to underschedule and then buy in real time. To remedy this, the incentives need to be changed to give sellers an incentive to sell day ahead or in forward markets, and to give buyers both the ability to minimize their purchasing costs with the ability to forward contract and a disincentive to purchase in real time. For example, loads that purchase real time energy could be required to pay a premium above the currently-calculated prices and penalties for real time purchases. IOUs could also be allowed to purchase energy in forward markets outside the PX. On the supply side, one way to encourage generators to offer more energy in the forward markets would be to reduce the financial reward for providing replacement reserves. For example, any payments to a generator for providing replacement reserves could be considered as a down payment for any energy produced from the generator in real time. Thus, the price paid to the generator for such real time energy would be reduced by the amount paid for providing the replacement reserves.

The Commission could direct a further investigation of generators with abnormally high unplanned outage rates or bidders into the PX to examine whether individual market participants may have engaged in withholding or price manipulation. It may be appropriate for the Commission to take a more active role in investigating and dealing with individual instances of market power abuse. For example, one way to physically withhold capacity from the market is to contrive a forced outage. Of course, generation equipment will break down from time to time even in a competitive market; so unexpected, forced outages will naturally occur in any market. However, when a generator experiences an outage, capacity in the market is reduced, and that tends to raise the market price. So a generator might be able to exercise market power and raise the market price by contriving a forced outage, and thus, physically withholding capacity. It may be difficult to determine whether a forced outage is legitimate or contrived. However, when a generator's forced outage rate is abnormally high, especially during periods of tight capacity, it may be useful to investigate the outage in more detail to determine whether it has been contrived as an exercise of market power. If the outage is determined to be contrived, penalties could be imposed in order to deter similar future behavior.

In the time available for this investigation it was not possible to determine whether individual market participants abused their market power. An option available to the Commission is to direct staff to conduct a further investigation into individual conduct during the past summer.

With respect to future conduct, the Commission can revise its reporting requirements and market monitoring methods to provide a more systematic basis for monitoring for instances of market power abuse. Periodic market investigations, such as this investigation, are resource intensive efforts for the Commission staff as well as the Cal-ISO, PX and the market participants, that do not provide the kind of regular information collection needed to monitor the market and the behavior of individual participants on a regular basis. For example, the Commission could require generators to report unplanned outages to the Commission contemporaneously with the outage or soon thereafter. Although the Cal-ISO and the PX have market monitoring staffs, they do not have the same authority as the Commission to investigate individual behavior, and to take action against individual market participants.