ELECTRICITY MARKET REFORM IN CALIFORNIA

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> "…the Commission's goal has been to balance, on the one hand, holding overall rates to levels that approximate competitive market levels for the benefit of consumers, with, on the other hand, inducing sufficient investment in capacity to ensure adequate service for the benefit of consumers. We believe that a well functioning competitive wholesale power market in California, which includes a well functioning regional transmission grid, is a fundamental part of the solution to the supply problems and price volatility in California….
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> … It is important to get the fundamentals right and to devise a roadmap that takes into account the needs of the market and the regional implications of electricity trade." [2]

INTRODUCTION

The Federal Energy Regulatory Commission has proposed remedies for the problems observed in the California wholesale markets during the summer of 2000.[3] The Commission findings properly emphasize the importance of defects in the California market, which by now has a history of largely unsuccessful reforms. Furthermore, the Commission highlights the need both to address the immediate problems in the market as

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[2] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, pp. 4, 18.

[3] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000.

well as to initiate a successful redesign process that will lead to a workably competitive regional wholesale market.

The present paper examines the direction laid out by the Commission in light of the available analyses of the problems and the record of the market design process in California.[4] We submit that the Commission's proposals need substantial clarification, revision and extension. The clarifications should eliminate certain ambiguities in the Commission's guidance, ambiguities that could complicate or completely undermine the Commission's intent. The revisions point to modifications of the short-term transition that would be more consistent with the goal of reforming the basic flaws in the California market design. The extensions focus primarily on the immediate need to embrace the fundamental reforms that are sure to be required and for which further delay could threaten the success of the entire endeavor.

The issues are important for California, but the implications extend well beyond the boundaries of this particular market. The example of the California market is cited in virtually every restructuring policy discussion, and the California market interacts directly with the rest of the electricity market in the Western system. The events have started a process that has produced many attempts to sort out the complicated issues. However, the debate is not likely to be settled through the by now familiar process of the Commission responding to stakeholder initiatives. The current institutions are unlikely to produce workable reforms in California, so the Commission must provide the necessary guidance and direction. Importantly, the Commission has a great deal of evidence and experience to define reforms that would be likely to work.

THE FATAL FLAW

California built its market design on a flawed premise. It is a commonplace that electric systems are both complicated and highly interdependent. Over short horizons of a day or less, generating facilities must work through the transmission network to provide the multiple products of energy, reserves and ancillary services. The same generating facilities must provide all of these products, in the right amounts, and with very limited tolerances. The simple physical reality dictates that these services must, in the end, be coordinated by a system operator. There is no other choice available with our current technology, and every electric system has such a system operator.

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[4] Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000. California ISO (CAISO), Department of Market Analysis, "Report on California Energy Market Issues and Performance: May-June, 2000," August 10, 2000. Severin Borenstein, James Bushnell and Frank Wolak, "Diagnosing Market Power in California's Restructured Wholesale Electricity Market," August 2000. Frank A. Wolak, Robert Nordhaus, and Carl Shapiro, "An analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," September 6, 2000. Northwest Power Planning Council, Study of Western Power Market Prices Summer 2000, October 11, 2000. California Power Exchange Corp., Compliance Unit, Price Movements in California Electricity Markets, September 29, 2000.

The flawed premise of the California market design was that this inescapable reality could be ignored or minimized in an effort to honor a faith in the ability of markets to solve the problems of coordination. Worse yet, the design of the California market embraced the notion that what little the system operator would do should be done inefficiently in order to leave even more coordination problems for the market to solve. This was an unprecedented experiment in markets that did not work in theory.[5] We now know that it did not work in practice either.

The failed experiment is at the root of many of the market defects. And the root is deep. The principles have been embodied as part of the so-called "four pillars" of the California market design.[6] Throughout the review of the market design in the intensive process that began when the Commission identified the "fundamentally flawed" congestion management system, the California Independent System Operator (CAISO) has reflected the will of some stakeholders that above all else the four pillars must be preserved.[7]

These four pillars include:

- The design should “separate the forward energy markets from the ISO forward transmission market.”
- The design should “use second-price auction and marginal cost pricing for transmission.”
- The design should “utilize the principle of market separation,” such as requiring the ISO to preserve balanced schedules for each scheduling coordinator, notwithstanding the ISO’s need to adjust these schedules to manage congestion and balance the system.
- The design should “use zonal congestion design where prices within a zone are close enough to use one price for the whole zone.”

Only the second principle, to use marginal cost pricing, has a basis in theory or been shown to be workable in practice. Unfortunately, many of the perverse incentives in the California market arise precisely because the ISO is not allowed to apply even this principle consistently. At the same time, the remaining three pillars stand in opposition to the reality of how electric systems must work.

Separating forward energy markets from the ISO’s forward transmission markets is a mistake. Over short horizons, there is no distinction between energy dispatch and transmission use. Once we know the dispatch of plants needed to produce energy to meet load, the use of the transmission system is determined. It is a fallacy that these can be determined separately, or that these functions do not have to be carefully integrated to achieve both economic efficiency and reliable operation. Furthermore, this same flawed

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5 William W. Hogan, "A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy," Electricity Journal, December 1995.

6 “Congestion Management Reform,” presentation by the California ISO, March 17, 2000.

7 See, for example, California ISO, Congestion Management Reform Recommendations, Appendix E, July 28, 2000.

market separation principle leads to explicit prohibitions of economic dispatch. The separation of day-ahead transmission and energy markets creates problems that could be and have been avoided elsewhere.

Similarly, the principle of market separation that gives rise to the requirement for individually balanced schedules imposes constraints on operations that are designed solely to create opportunities for otherwise unnecessary transactions for the California Power Exchange (PX) and other scheduling coordinators. Aggregate balancing is required by the physics. But individual balancing is not required, often not efficient, and sometimes not even possible. The restriction is entirely artificial and makes it harder for the ISO to coordinate the market. Moreover, the restriction appears likely to increase the capacity shortage in the California market by increasing the CAISO's demand for capacity (to provide regulation) and requiring market participants to withhold capacity from the energy markets in order to provide adjustment bids.

Likewise, the zonal pricing system defines a requirement that should not be a requirement at all given the conditions in its definition. If the (true) prices in a zone were "close enough," there would be no need to convert them to one price. Furthermore, we know by now that the implied simplification of the zonal system was a mirage, and its implementation requires more and more complex contortions to counteract its perverse incentives. The real impact of zonal aggregation is to convert (true) prices that are not close into a single price that gives the wrong incentives just when incentives matter most.

These ill-advised pillars have trapped California in a box that excludes meaningful market reform. The Commission has recognized some, if not all, of the pathologies that fester inside this box. As the Commission has noted, the separation of the roles of the ISO and the PX in dealing with short-term coordination is a source of continuing trouble. The requirement for individually balanced schedules, rather than a collectively balanced system, serves no good public policy purpose. The prohibition against economic dispatch in real time necessarily reduces efficiency and forecloses a market-based option that is fundamental to workable markets in other systems. The continued pursuit of "simplified" zonal designs, that are truly complicated in practice, reflects the perverse philosophical commitment to preventing the CAISO from doing well what it must do of necessity. The initial complete and still partial separation of markets for energy, reserves and other ancillary services imposes demands on market participants, and on the supply of generating capacity, that could be alleviated easily in the use of a combined optimization that only the CAISO could perform.

The recitation of design defects attributable to the flawed pillars could be extended.[8] But even this short summary of the experience in the reform process, and the continued adherence to the fatally flawed premise of the California market design, presents the Commission with an unhappy combination of circumstances. First, the California market will not be amenable to reform without stepping outside the constraints imposed by the flawed pillars. Second, the California participants have demonstrated

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[8] See, for example, Scott Harvey and William W. Hogan, "Comments on the Congestion Management Proposals of the California ISO," August 31, 2000.

repeatedly that they cannot take this step on their own, and will not allow the ISO management to take it for them.

The Commission, therefore, will have to take the initiative to drive the process in the right direction. This is essential for several reasons. The obvious importance of the California market should be enough to declare an end to the failed experiment and turn to a superior market design in place elsewhere that has proven itself in both theory and practice. Furthermore, the example of California is unavoidable in establishing precedents or creating obstacles for the development of Regional Transmission Organizations (RTOs) in other regions. Without a fundamental correction in California, the Commission will face serious complications in the development of workable regional markets well beyond the borders of California.

There is an understandable focus on high prices and efforts to mitigate the impact on California consumers. Near-term efforts to define just and reasonable prices receive immediate attention, often at the expense of efforts to correct the underlying flaws in the market. But even here the design flaws intrude. They confound diagnosis and treatment of the market ills in California. Initially, high prices in California were seen as *prima facie* evidence of the exercise of market power. However, closer examination of the structure of the market and its rules reveals a more complicated story that implicates the interaction of bad market design and shortage as at least a prominent feature of the California experience.[9] Without the fundamental reforms in market design, it may be impossible to separate the effects of market power from these other elements. And without a better diagnosis, it is hard to know what treatments to prescribe to mitigate market power, or even if market power is a part of the problem. Furthermore, if the real problems have been a combination of a shortage of capacity and high cost energy, market reform may be essential to achieving just and reasonable prices.

Direction from the Commission should be specific and comprehensive, both as to the final destination and the path for transition. The Commission's recognition that it must confront the difficulties of market design is a promising start, but more is required. It must now get the market design right and ensure that the flawed market design elements now evident in the California structure are not allowed to take root in the emerging RTOs elsewhere.

THE COMMISSION'S PROPOSALS

The Commission has reviewed the accumulated experience in California and produced a series of proposed actions for the immediate future and for more fundamental reform. The initial actions include: [10]

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[9] Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000. Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000.

[10] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 5.

- the elimination of the requirement that the three investor-owned utilities (IOUs) -- Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SoCal Edison), and San Diego Gas & Electric Company (SDG&E) -- must sell into and buy from the PX;
- the addition of a penalty charge for deviations in scheduling in excess of five percent of an entity's hourly load requirements and the disbursement of penalty revenues to the loads that scheduled accurately;
- the establishment of independent, non-stakeholder Governing Boards for the PX and the ISO;
- the establishment of generation interconnection procedures; and
- a new form of "soft" price cap at $150.

Further, the Commission identified a number of structural reforms that must be addressed, including: [11]

- the submission of a congestion management redesign proposal;
- possible changes to the auction mechanisms;
- improved market monitoring and market mitigation strategies;
- demand response programs by the ISO and Scheduling Coordinators;
- elimination of the requirement for balanced schedules; and
- new approach to reserve requirements.

This is an ambitious agenda, pointing towards undertaking a comprehensive redesign of the entire California market structure. It raises many questions that could lead to extensive discussion and debate. However, in making the case that the agenda is not prescriptive enough, it is better to concentrate on the main points. These observations will serve as a backdrop for the clarifications, revisions and extensions that we see as dictated by the Commission's analysis and the serious problems that remain.

Governance

The California governance arrangements have failed to meet the basic test of operating success. The governance mechanism that produced the flawed initial market design evolved into the stakeholder boards of the CAISO and the PX. As is now clear, this governance mechanism has been unable to correct, or even acknowledge, its initial mistakes. The Commission has concluded that California needs a new, more independent, governance mechanism. This is an important step that will have major impacts both inside and outside California.

Whatever the necessity of improving the governance of market institutions in California, there is little reason to hope that this alone will be sufficient to ensure timely

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[11] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 5.

or sensible reforms. Responsibility for the existing problems in California rests not just with its governing bodies. Regulators in Washington and California accepted and approved the defective market design, albeit at a time when there was little experience with operating electricity markets in the United States. The most important guidance regarding improvements of these market designs is not likely to come from the as yet unnamed new boards, especially given the delay in their arrival on the scene and the natural requirement that they will spend time understanding the current market institutions and problems, and making their own mistakes. In the meantime, the Commission must do the hard work of sorting through market design issues and weeding out designs that have failed from those that have proven to be workable.

Sole reliance on the new boards to do the hard work for the Commission could be further complicated by the guidance the Commission has given as to the composition of these Boards: "[t]he Boards should include members with experience in corporate leadership (at the director or board level) or professional expertise in either finance, accounting, engineering or utility law and regulation. The PX board should include members with expertise in areas of commercial markets and trading. The ISO board should include members with experience in the operation and planning of transmission systems." [12] This could be interpreted as direction for the expertise sought separately for the CAISO and PX boards to preserve a distinction in their functions that would codify the fatal flaw of market separation. This would be a mistake. In particular, the CAISO functions should include the necessary understanding of what needs to be done in the management of short-term operations to support both reliability and markets.

The change in governance may help, but it is not likely to be decisive in the near term. Explicit guidance from the Commission regarding the nature and trajectory of reforms will be essential if market reform is to be accomplished within an acceptable time frame.

Market Separation

The flaw of market separation receives attention from the Commission in its direction regarding the functions of the CAISO and the PX. The Commission proposes with one hand to abolish the requirement for utilities to purchase solely from the PX, and it asserts that it wants to eliminate the balanced schedule requirement. But with the other hand the Commission reinforces the artificial distinction between the energy market and transmission management: "We propose to temporarily correct the current situation by limiting the ISO to only the functions needed to reliably operate the transmission system, i.e., provide a balancing service rather than running an energy market."[13] In addition, as discussed above, the Commission may be construed to having directed the new independent Boards to have correspondingly different expertise. Further, in its detailed discussion, the Commission requires not the elimination of balanced schedules but no

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[12] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, pp. 28-29.

[13] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 24.

more than that the PX and the CAISO discuss in the future how to better integrate the day-ahead markets.[14] The Commission is silent on the contradictions of these ambiguous instructions and fails to address the impact of the market separation requirement on the capacity shortages in California.

Further, in its discussion of the use of spot markets the Commission wrongly focuses on the symptoms rather than the disease. The symptom is the so-called underscheduling in the day-ahead market and greater reliance on the spot market. The pathology is the market structure that gives the wrong price signals to the participants and forces inefficiency that contributes to a capacity shortage. If the prices were right, there should be no need for penalties or special rules to force market participants to act in ways that go against the market incentives. As we have seen in other markets, it is possible for day-ahead and real-time markets to work without special penalties or rules and without the pathologies present in California.

The ambiguity in the guidance and the confusion it will create are a recipe for delay and further *ad hoc* reforms. The Commission should face the reality of electricity systems and the extensive analysis that supported its directions in Order 2000.[15] The CAISO should be given the clear responsibility to run an efficient day-ahead and real-time market, in support of an efficient competitive market. Pricing rules in each market should be based on standard marginal cost principles and be consistent across markets. Any attempt to straddle the four pillars and maintain market separation is bound to fail. There should be an unambiguous decision and direction to give the CAISO the responsibility to operate an integrated system for day-ahead and real-time scheduling, balancing, congestion management, ancillary services, reserves, and so on, recognizing that these and their associated pricing must be parts of an integrated whole.

Forward Contracting

Freeing utilities from restrictions on forward contracting is a move in the right direction. In a real market, there would be no such restrictions. The arguments for the restrictions in the first place were at best problematic. Whatever the original merits, the arguments depended in part upon other market reforms that would allow for vigorous competition to serve retail loads. These other reforms were not put in place. In addition, the well documented effect of the rate freeze and stranded asset recovery mechanism created the worst possible combination of small customers left *de facto* without access to retail suppliers who could provide price stability, and utilities precluded from providing any hedging services.

Removing the restrictions on forward contracting is one thing. Putting formal requirements or informal pressure on buyers to sign long-term forward contracts would be quite something else. The expectation that merely allowing utilities to participate in

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14 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 30.

15 William W. Hogan, "Regional Transmission Organizations: Millennium Order on Designing Market Institutions for Electric Network Systems," May 2000. (available at ksgwww.harvard.edu/people/whogan).

forward contracting necessarily would be the solution to high prices is problematic and not supported by the Commission's staff report. "[H]olding forward contracts does not guarantee that consumers will incur lower total energy costs. These costs ultimately depend on the relative level of prices in the forward and spot energy markets."[16] To the contrary, putting pressure on buyers to sign contracts in the present environment may make things worse. It is doubtful that requiring buyers to sign forward contracts would improve matters if the high prices are largely due to the exercise of market power,[17] and if the high prices are largely due to high costs and capacity shortages, requiring California buyers to sign forward contracts could make things worse not only in California, but in a broad part of the Western system (WSCC).

Forward contract prices after Summer 2000 were much higher than for the Summer 1999, and a regulatory requirement that buyers increase their demand for such contracts can only be expected to make the contract price increase. Furthermore, the complications of getting the utilities back in the long-term supply business have been ignored. A rush to extensive long-term forward contracting now may be closing the barn door too late. A return to new but strangely familiar stranded cost hearings may not be far in the future. One of the purposes of electricity market reform was to provide customer choice. It would be inconsistent with this purpose if the distribution utilities were to be required to enter into forward contracts to buy electricity at prices that may turn out to be much higher than what customers are actually willing to pay for that power. Recall the natural gas markets in the 1980s with high contract prices that precipitated the restructuring of the gas industry.

It is not clear that the Commission's proposal would require long-term forward contracting. The language about forward contracting and the emphasis on real-time penalties could be interpreted as applying only to day-ahead scheduling.[18] If this is the Commission's intent, it should be clarified. If not, then the role of long-term forward contracting deserves much more examination before committing to a new round of sunk costs.

The Commission should on the other hand take steps to eliminate artificial barriers to forward contracting and ensure that competitive electricity providers are able to participate in the market and offer load management services to end users.

Soft Price Cap

The soft price cap proposal is novel and raises many new issues. It does not appear in the staff report and there is little critical analysis of the implications, other than

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[16] Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000, p. 5-9. See also, Scott M. Harvey and William W. Hogan, "California Electricity Prices and Forward Market Hedging," October 17, 2000.

[17] Scott M. Harvey and William W. Hogan, "California Electricity Prices and Forward Market Hedging," October 17, 2000. (available at ksgwww.harvard.edu/people/whogan).

[18] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, pp. 24, 41.

the discussion of Commissioner Hébert. Essentially the soft price cap appears to be an attempt to straddle two auction price regimes, with market-clearing prices applying below $150 and pay-as-bid systems applying above $150. Below $150 it would seem that any price would be acceptable. Above $150, there would at least be requirements for further review by the Commission and possible refunds.

It is uncertain what is intended. One possibility is that the Commission intends to require and enforce cost justification for all bids in excess of $150. If this is the intent, the proposal in effect lowers the existing price cap and formalizes the CAISO practice of making out-of-market purchases in order to obtain supplies available only at prices above the price cap. [19] In this case, the Commission should recognize that requiring cost justification of generator bids, particularly under a pay-as-bid system, will impose substantial burdens on the Commission that would rival those under wellhead price controls in the natural gas industry. Some of the issues the Commission and its staff would have to address include:

- Would fuels be priced based on their acquisition price or their current market price?
- Would emission allowances be priced based on their acquisition cost or their current market price, and how would market prices be determined?
- Would firm transportation charges be included in costs, and if so how, or only interruptible (and thus avoidable) gas transportation charges?
- How would the cost justification account for start-up and no-load costs?
- How would the opportunity costs of limited energy resources such as pondage hydro be measured?
- How would expected ancillary services prices be evaluated in measuring opportunity costs?
- How would imports and exports be priced?

Moreover, even if this regime were successfully applied the price discrimination and price averaging implicit in the pay-as-bid market structure would likely deter, rather than promote, forward contracting. Finally, such a cost based approach would appear to deter investments in new capacity, improved heat-rate performance, and reduced emissions, all of which will not be made unless they earn more than their short-run costs and all of which are necessary if California is to address the three problems of capacity shortage, high gas costs and high emissions.

Alternatively, the soft price cap might be truly soft and not require cost justification. Hence, there would be no price cap for any entity that is willing to file a report to FERC and face the possibility of a refund. If this is the Commission's intent,

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[19] Commissioner Hébert for one is concerned that this requirement would act as a *de facto* price cap at $150. See Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Concurring Opinion of Commissioner Hébert, Docket No. EL00-95-000, Washington, DC, November 1, 2000.

there might be little impact on consumer prices (particularly if the principal sources of those high prices are high costs and regional capacity shortages rather than the exercise of market power). Even so, the proposal might serve to deter entry and new investments, thus combining the worst of both worlds, high consumer prices and little or no new investment.

As with any price cap, the incentives run against the operation of markets and make the mechanism a source of complication in achieving a transition to a more market-like mechanism. It would be especially problematic for prospective new entrants. Consider a competitive existing generator with production costs below but opportunity costs above $150. The opportunity costs should set a floor on its bid in a competitive market. Under a truly "soft" price cap, the risk for such an entity of bidding above $150 would be limited to the cost of filing and review by the Commission, plus the possibility that a refund may be required to return its short-run operating profits in excess of $150. There would be no rational reason not to bid the supplier's opportunity costs, as the worst case outcome would be no worse than if it did not try to capture its opportunity costs in its bid. By contrast, consider the new generator that needs a significant number of hours with revenue above $150 to justify the fixed costs of building a plant and entering the market. No matter what the Commission says now, the new generator (or the generator contemplating closing a plant, or a generator contemplating an investment to improve generating performance or reduce NOx emissions) would face a larger maximum risk and would have to evaluate the chance that it would make a cash investment and then not recover its required return. In this case, it is not simply a matter of failing to capture its opportunity costs and being no worse off than if it had not tried, because the ability to capture opportunity costs may have provided the basis for an investment that would be sunk and would fail to recover its cost of capital. It is easy to imagine that this soft price cap would have almost the same effect as a hard price cap for such entrants, namely discouraging new entry. Given the short supply situation, this would be just the wrong incentive.

In addition, a soft price cap would face the same problems of any pay-as-bid market. To the extent that shortage is driving the high prices in California, this rule would indirectly reinforce the problematic features of bidding and scheduling.

Auction Mechanisms

The Commission expressed an interest in the possible benefits of switching to a pay-as-bid auction format rather than the originally intended design of a uniform price auction. Electricity markets that rely on uniform price auctions to clear markets exploit a simple argument based on the law of one price. The law of one price says that in a decentralized market for a homogeneous commodity, trade will tend to converge towards a common market-clearing price. In the case of electricity, where decentralized trading is foreclosed in the final day-ahead and real-time markets, this convergence is not possible and the simple approach is to use what the market would produce if only there were enough time and no transaction costs.

Whenever these uniform price electricity markets encounter trouble for any reason, someone notices that market participants are responding to the incentives of the uniform price auction by bidding something below the market-clearing price. They then leap to the *non sequitur* that paying the bid rather than the market-clearing price would somehow reduce average prices. A moment's reflection would suggest that the same market participants who respond to the incentives of the uniform price auction would also respond to the incentives of the pay-as-bid auction. Now the incentive would be to bid the market-clearing price.

As the staff report summarizes, the results would be the same price and revenue flows as under the uniform price auction.[20] This assumes, however, that there would be no uncertainty and no transaction costs. In the presence of uncertainty and transaction costs, there will be errors in the bids. The one sure thing that these errors will produce will be higher true costs through inefficient choices in the ultimate dispatch. There is no available evidence that the result would be lower prices. There are studies that suggest that both costs and prices would be higher.[21]

This general observation applied to any commodity auction applies with special force to something as complicated as the bids for a security-constrained economic dispatch. We saw what could happen in such a market when California operated fully separate energy, reserve and ancillary services markets.[22] In effect, this was an approximate prototype of a full pay-as-bid market. It was a stunning failure, the first in a line of special California problems. To cite another complication, consider the problems of transmission congestion management if everyone is bidding to make sure that the bid is close to the market-clearing price. For example, in PJM the presence of transmission congestion can change the market value of generation by an order of magnitude. Every generator would be compelled to consider the likelihood of transmission congestion in each interval, and change its bids accordingly. This embrace of a pay-as-bid rule would be a nightmare for the system operator and the competitive bidder, but a godsend for any generator who wished to cloak the exercise of market power.

Market Power and Shortages

High prices in the summer of 2000 arose because of a combination of factors. Faulty market rules created both inefficient dispatch and incentives for behavior that complicated market operations. Costs were up due to higher natural gas prices and tightening markets for emission allowances. Capacity was reduced because of the low availability of hydro power, a failure to invest in generating capacity in California, and increased congestion in the transmission system. Demand in areas not exposed to market prices grew at a rate that surprised most observers. On these points there is no dispute. In addition, there are those who argue that the high prices were exacerbated by the exercise of market power.

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[20] Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000, p. 5-15.

[21] John Bower and Derek W. Bunn, "Model-Based Comparisons of Pool and Bilateral Markets for Electricity," Energy Journal, Vol. 21, No. 3, pp. 1-29.

[22] Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000. (available at ksgwww.harvard.edu/people/whogan).

The need to fix badly flawed markets should be beyond dispute after the evidence of the failed experiment in California. The impacts of increased production costs and shortages are easy to understand, if not pleasant to endure. Markets respond to scarcity by increasing prices, and the increase in price creates the incentives for adjustments in supply and demand. Were it not for the large wealth transfer, the analysis of the proper response to scarcity would lead to the uncontroversial conclusion to let the market work.

The controversy in California centers more on the role of market power, and separating how much of the increase in prices is the result of the exercise of market power versus how much is from the more conventional explanation of scarcity, albeit scarcity created in part by the market design. In this regard, the debate is confused because we are dancing around the words where the truth may be hard to face. The confusion is evident in the Commission's summary of its findings and conclusions: "[w]hile this record does not support findings of specific exercises of market power, and while we are not able to reach definite conclusions about the actions of individual sellers, there is clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates under the FPA." [23]

The traditional definition of the exercise of market power would apply to circumstances when generators withhold some capacity and leave it idle in order to raise the market price. The withholding suppliers are presumed to make more money through the increased price on what they do supply than they lose on the supply they withhold.[24] There is an unambiguous policy conclusion regarding this exercise of traditional market power. If it is occurring on any significant scale, it is a problem and regulatory intervention is indicated. The preferred mechanisms would be through bids caps, or divestiture, applied to the offending suppliers, as discussed below.

The difficulty in the present case is that there has been no direct showing that such traditional market power has been exercised at all, much less that it has been exercised on a widespread and significant basis. [25] The often mentioned tendency of generators and loads to avoid the day-ahead market in preference to the real-time market is a response to bad market design and pricing incentives (including price caps), but does not demonstrate the exercise of market power. If these participants ultimately transact through the real-time market (for either energy or reserves), there is no final withholding of capacity. Even a 1 MW generator would have an incentive to follow these incentives. This is not the traditional exercise of market power.

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23 Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, p. 3.

24 In the presence of transmission bottlenecks, it is possible to exercise market power by increasing some supply in order to force reductions elsewhere, but this does not change the thrust of the present argument.

25 Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000, pp. 2-4. Federal Energy Regulatory Commission, "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Part 1 of Staff Report on U.S. Bulk Power Markets, November 1, 2000, p. 5-16.

In contrast, sometimes the term "market power" is applied to something else in analyses of the California experience. This is clearest in the discussion of market power with the occasional cryptic reference to the definition: "[t]he data also indicate some attempted exercise of market power, if the standard of bidding above marginal cost is used,…"[26] This definition flows from a view that the California market is a pure uniform price auction and that bidders without market power should bid their own opportunity cost. However, there are several translation steps that are implicit and problematic in this definition.

The distinction between direct marginal cost and opportunity cost is sometimes lost in the discussion. Hence, a competitive bidder whose direct cost of generation is $40 but who could sell the same energy outside California for $100 should bid no less than $100. This would not be an exercise of market power. Furthermore, the California market is not a true uniform price market. In fact, the many peculiar design features in the California market mean that the market-clearing price in related markets, such as ancillary services, should determine the opportunity cost in others. Hence, even a small 1 MW generator should be anticipating the willingness to pay of the market and try to bid so as to ensure that it is paid the market-clearing price. Under the California rules, the rational bid of the competitive generator can easily be to pick the largest price at which it will still be called into use. This is not withholding, it is a rational response to market incentives. To the extent that this is caused by market design problems, fixing the design should change the bidding behavior. To the extent that the market-clearing price is due to scarcity, however, the resulting price impacts and behavior of the bidders is consistent with what we would expect in a competitive market and cannot be avoided without eliminating the market.[27]

Dispelling the semantic fog should be a high priority for the Commission. If there is significant exercise of traditional market power through withholding, this has important policy implications. The preferred response would be bid caps targeted at those exercising market power in the short-run and divestiture in the long-run, and this action alone might be sufficient to moderate the average price impacts. However, if the explanation lies elsewhere, the policy implications would be different. If scarcity and higher costs are the dominant forces, bid caps on large suppliers and divestiture would have little, maybe no, impact on the outcome of prices and production. Most importantly, price caps that appear more justifiable in the presence of traditional market power become exactly the wrong approach in dealing with scarcity.

Other Proposals

The Commission identifies a number of other initiatives that seem important, uncontroversial, and overdue. These would include the promotion of greater demand-side response, improved congestion management, establishment of non-discriminatory

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[26] Federal Energy Regulatory Commission, "Order Proposing Remedies for California Wholesale Electric Markets," Docket No. EL00-95-000, Washington, DC, November 1, 2000, Appendix D.

[27] Scott M. Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000. (available at ksgwww.harvard.edu/people/whogan).

interconnection procedures, enhanced market monitoring, and full implementation of an effective RTO that complies with the spirit of Order 2000.

MARKET REFORMS

The list of necessary reforms for the California market is long, and the difficulty of identifying and fixing all of the problems has been exacerbated by repeated *ad hoc* reforms that have dismissed theoretically sound and proven design principles. A transition will be necessary, but it must be guided by a set of principles that are consistent with a workable, efficient, and sustainable market. The necessary principles have been articulated in a number of different forms and forums.[28] Here we restate and summarize the key principles and their rationale before addressing the transitional steps that will be needed in the near term.

1. *The ISO must operate, and provide open access to, short-run markets to maintain short-run reliability and to provide a foundation for a workable market*.

These short-run markets include, at a minimum, the real-time balancing market associated with the real-time dispatch, along with associated ancillary service markets – for regulation and operating reserves -- necessary to maintain reliability. A bid-based real-time dispatch is the means by which the ISO provides a real-time balancing and spot market, maintains system balance, and provides economic redispatch to manage congestion. We restate this principle first because it has been only weakly embraced in California and is now further threatened by misguided attempts to solve the problem of "underscheduling," a phenomenon whose causes lie elsewhere and whose solution does not require limiting access to an essential market.

While the ISO's real-time dispatch provides the most essential of all short-run reliability functions – it is the true "provider of last resort" in all electricity markets -- the real-time spot market that flows from this dispatch provides the cornerstone for an effective, workable market. Real-time spot prices provide a reference for writing forward contracts and effectively eliminate the problem of liquidated damages when either party fails to perform (i.e., to generate or consume) as expected. Access to this market allows contracting parties to avoid the burden and expense of precise or even approximate load following. Imbalances are simply supplied or absorbed by the ISO's real-time dispatch and the parties are simply settled at the market-clearing spot prices that flow from that dispatch. With an open spot market, moreover, generators have a ready market for their uncontracted output, and loads have a dependable market to obtain energy to meet their uncontracted demand. Hence, the ISO's real-time market is not just a "balancing market," it is an open spot market that provides important options for all market participants and a standard reference and backup for forward contracting.

[28] For example, see the 17 design recommendations submitted to the Commission by San Diego Gas and Electric Company. "Comments of San Diego Gas and Electric Company on Order Proposing Remedies for California Wholesale Electric Markets, Attachment A," filed November 22, 2000.

In California, this necessary cornerstone of an effective market has been undermined by rules that prevent the ISO from performing an efficient economic dispatch. An efficient dispatch would follow from the voluntary submission of bids from generators and dispatchable loads and the logical, efficient use of those bids by the ISO to arrange a security-constrained, economic dispatch. Such a dispatch would simultaneously balance the system, clear the market and redispatch generators to relieve all congestion, and do so at the lowest as-bid cost, given the bids and the constraints that had to be honored. Security-constrained economic dispatch is the bedrock principle of efficient electricity operations, and it should be the foundation for an efficient real-time market. Yet current market rules in California prevent the ISO from attempting an economic dispatch when the system is congested, instead forcing the ISO to deviate from an unconstrained merit-order dispatch only enough to relieve the constraint but no further, even if a more efficient –i.e., lower-cost – dispatch is possible given the bids. The Commission should direct the ISO to remove this "minimum shift" restriction on economic dispatch immediately.

Once the Commission removes the restrictions on an economic dispatch, it should also ensure that all parties have open, unlimited access to the associated spot market. Unfortunately, the Commission proposes to embrace one of the fundamental design flaws of the California market by imposing penalties and other measures to discourage parties from using the ISO's real-time spot market. Rather than seeing the real-time spot market and open access to that market as the cornerstone for a much broader market, the California philosophy has mistakenly regarded the real-time spot market as a "residual" market necessary only for maintaining real-time reliability. Any use of that market beyond some arbitrarily low level is deemed to be a problem. This is a mistaken view, incompatible with the important role played by the spot market.

The Commission now proposes to approve this flawed, narrow view and to enforce it by penalizing parties that deviate from their forward market schedules by more than five percent. Indeed, the Commission seems dismayed that the market's voluntary use of the ISO's real-time market has "forced the ISO to operate a market," as though the operation of real-time spot markets by ISOs were a novel approach and incompatible with Commission policy and sound market design. This is dangerous view that will only foster restricted, inefficient markets in every RTO.

The Commission should recall that until June of this year, the PJM market, to which the Commission has repeatedly pointed as a model for emulation, consisted of a real-time spot market based on voluntary bids submitted to the ISO in conjunction with arranging a security-constrained economic dispatch. All "forward" markets were entirely bilateral and voluntary, as there was no bid-based forward energy market operated by PJM until June 1, 2000. The key features of the PJM spot market were (and continue to be) open, unlimited access, without penalties. Parties are free to use this spot market to any degree consistent with their commercial interests, and they are entitled (obligated) to receive (pay) the spot market prices for the quantities they sell (purchase) in that market. The success of this open spot market and the important role it plays in supporting the overall PJM market structure were surely understood by the Commission when it declared in Order 2000 that open, non-discriminatory access to a real-time balancing market is necessary to achieve non-discriminatory access to transmission. And this is clearly why a real-time balancing market is a required function of every RTO.

Since June, PJM has also operated a day-ahead market in which parties can bid to buy and sell energy and transmission in an integrated market with consistent pricing. Any yet parties are free to use the forward market or not, and rely on the real-time spot market or not, as best suits their commercial interests. The parties are not penalized for their choices, beyond the requirement that they be settled at the market-clearing prices in whatever market they use.

Both the California ISO and the Commission now seem preoccupied by the fact that substantial percentages of load (and generation) often "underschedule" in the ISO forward markets and show up only in the real-time market, forcing the ISO to scramble to arrange sufficient resources to meet the real-time demand when real-time prices are soaring. The Commission should recognize that it is not "underscheduling" that caused real-time prices to soar or the ISO to have to scramble to meet real-time demand but the high energy prices and capacity shortage. Neither of these problems is solved merely by scheduling resources day-ahead. Indeed, there has been no demonstration that the external resources that were actually made available in real-time to allow the California ISO to meet real-time load would or even could have been offered in the day-ahead markets in which it would be mandated that loads cover their demands.

The reality is that markets do not work well in shortage conditions, particularly when price controls are in place. Underscheduling is merely a symptom of the other more fundamental problems, high energy prices, capacity shortages, and binding price controls. Treating the symptom of underscheduling is in practice a decision to do nothing and to hope for falling gas prices, high hydro-conditions, or a recession to solve the problem.

As the Commission recognizes, this problem of "underscheduling" is in part peculiar to the California market design and pricing rules and is not a serious problem in PJM. Curing the problem of "underscheduling" is thus a matter of fixing the California rules, not restricting access to an essential market. California artificially separates its forward markets for transmission (ISO) and energy (PX), and hence artificially separates its forward energy market from its real-time market. The ISO and PX then use different pricing rules – including different price caps – in their respective markets. For example, a higher price cap in the PX forward markets than the ISO uses in real time provides a strong incentive for load-serving entities to "underschedule" loads in the PX market so that they can gain the protection of the lower price cap in the ISO real-time market during high-price hours. From the loads' perspective, this is not "underscheduling;" it is rational scheduling in the market expected to have lower prices.

In PJM, or the similar market in New York, the incentives tend to be the reverse. While there are no explicit penalties for using the real-time spot market, there are reasons why the real-time prices may be higher if substantial quantities of loads bypass the day-ahead market and show up in real time. Moreover, the PJM and New York ISOs has an important tool -- a tool that the California market designers deliberately forbade the ISO to use -- that it can use to ensure reliability, even if substantial loads show up in real time.

For example, the PJM ISO offers a voluntary unit commitment service based on three part bids. Generators that wish to self schedule their units may do so, but those who wish to have their unit commitment optimized by PJM may submit bids that indicate not only their incremental energy prices but also their start-up costs and minimum generation costs. PJM then optimizes the unit commitment and ensures that enough units are committed to meet the ISO's independent forecast of total loads for the following day. Units that are committed must start up and/or be available on short notice, even if the load does not materialize and the units are not run. If they are not dispatched, or are not dispatched long enough to receive enough revenues at the market-clearing prices to recover their start-up and minimum generating costs, they are made whole. Hence, generators have an incentive to be available if needed.

In arranging the next-day's dispatch, PJM will optimize for all bid-in costs to meet the bid-in load. However, to meet the additional load that it forecasts but that did not bid in or schedule in the day-ahead market, the ISO will commit additional resources but optimize only to minimize start-up and minimum generation costs (but not incremental running costs). Thus, if the additional load shows up in real time, the PJM ISO will have committed enough resources to meet the total load reliably, but the market price may well be higher in real time. The reason is that the additional committed resources will tend to have low start-up costs but higher running costs, thus tending to drive the real-time price higher for loads that did not lock in prices day ahead.

The total effect of the PJM or New York approach is to encourage, but not force, parties to bid in or schedule in the day-ahead market, and to allow parties to use the real-time market as much as their commercial needs dictate. There are no penalties, but the ISO has the resources it needs to maintain reliability. In other words, maintaining reliability does not have to come at the expense of restricting access to the ISO's real-time spot market.

The key to avoiding artificial penalties is consistent pricing. If prices in each market reflect the true system marginal costs, then the incentives to use one over the other would reflect the true cost. There would be no need to be concerned about over or under using any market option.

Moreover, the Commission should recognize that artificial penalties on "underscheduling" can give rise to other bidding strategies by market participants that could make the situation much worse, not better, next summer. In particular, market participants with large FTR positions on transmission interfaces that are unconstrained in real-time could use such penalties to extract congestion charges from loads forced to schedule imports in the day-ahead market. Such cornering in the day-ahead market would be possible with mandatory scheduling requirements, but unsuccessful if customers could just turn to the real-time market as an alternative.

In sum, the Commission should reject the California restrictions on economic, least-cost dispatch for energy and ancillary services and refrain from imposing further restrictions or penalties on those who use the ISO's real-time market. The real-time market should be allowed to become an open, efficient spot market available to all market participants. To the extent that the ISO tends to have insufficient resources available to meet real-time loads, it should offer a unit commitment service to obtain those resources without restricting market choice.

2. *An ISO should be allowed to operate integrated short-run forward markets for energy and transmission.*

Currently, the ISO is prohibited from operating integrated day-ahead forward markets for energy, even though it is charged with operating forward markets for transmission. However, the markets for energy and transmission cannot be separated without creating serious coordination problems that lead to inconsistent pricing and gaming between the markets. These inconsistencies can also lead to infeasible schedules that are accepted in the forward market but which force the ISO to redispatch in real time.

ISO-operated day-ahead and hour-ahead markets can provide useful options to market participants, allowing them to lock in energy and transmission (congestion) prices in advance of real-time. They also provide a mechanism for parties to exchange their transmission rights; that is, to settle their existing transmissions rights and gain new entitlements that match their scheduled transactions.

The Commission should direct the ISO to operate open, bid-based integrated forward markets. These markets would allow parties to buy and sell energy, ancillary services and transmission. The integrated markets could come about by consolidating the ISO and PX or by allowing the ISO to acquire and/or operate the related day-ahead and hour-ahead functions of the PX and to integrate these energy markets with the ISO's transmission markets. The combined markets could then be fully coordinated under a consistent set of bidding, market-clearing and pricing rules.

Just as rules preventing the ISO from achieving an economic (least-cost) dispatch should be removed from the real-time market, so too should rules preventing the ISO from clearing the forward markets and relieving congestion at the lowest cost be removed. Currently, the ISO is prevented by the so-called "market separation rule" from relieving congestion at the lowest cost in its day-ahead and real-time markets. These rules should be eliminated.

The premise of these rules is flawed. The rules state that participants should be required to balance their schedules to match generation and loads rather than providing open access to the balancing service. With an open balancing market provided by an ISO or RTO, these impediments to trading are not justified. There is sometimes an argument that the ISO should not be allowed to effect "trades" between unwilling participants, but the argument has always been backwards. This California rule has historically prevented the ISO from effecting "trades" between parties who would be willing to have the ISO coordinate such trades. Hence, rather than forcing parties to accept an ISO result, the rule prevents parties from getting access to the ISO's market coordination. The "trades" referred to would occur if the ISO used the most cost-effective incremental bid from one party and the most cost-effective decremental bid from another party in order to relieve a transmission constraint in the most cost-effective manner. Thus, the market separation rule as applied to the ISO's forward markets is just another example of preventing least-cost dispatch, or in this case, least-cost redispatch to relieve congestion.

Importantly in the current context, by making market participants balance their schedules and manage congestion using only congestion adjustment bids, the market separation principle is likely to require both more capacity for use by the ISO, in the form of regulation, and more capacity to be held back by market participants to manage congestion (to support adjustment bids). The market separation doctrine may therefore have been an important contributor to the capacity shortages that have periodically affected the California and West Coast markets during the past year. The market separation doctrine and the other inefficiencies built into the California market design were built on an implicit premise that there would always be lots of excess capacity to accommodate that inefficiency. It should be clear after last summer that neither California nor the WSCC can afford that level of market inefficiency.

Moreover, in the long run, the market separation rule may intensify market concentration and facilitate the ability of dominant scheduling coordinators to exercise market power. By forcing the ISO to deal with each scheduling coordinator individually, rather than pooling the adjustment bids submitted by all scheduling coordinators, the rule favors the largest schedule coordinators with the largest and most diverse portfolio of adjustment bids. Over time, the natural advantages will concentrate the market, forcing the ISO to deal with the most dominant schedule coordinator(s) while leaving smaller entities at their mercy. Given its concerns about market power, the Commission should direct the ISO to eliminate the market separation rule and its companion requirement that parties submit only balanced schedules. [29]

Once the ISO is free to use all the bids to achieve a least-cost redispatch to relieve congestion, it can then use that redispatch to deal with all of the congestion in each market. Currently, the California ISO does not solve all congestion in its forward markets, because the market separation rules make it very difficult to do so. Thus, in its forward markets, the ISO uses adjustment bids to relieve only the congestion between existing zones (inter-zonal congestion) but does not attempt to resolve congestion within each zone (intra-zonal congestion). The result is that the ISO is forced to approve schedules in the forward market that it knows are infeasible and that will require it to solve through redispatch in the real-time market. (Note that balanced schedule requirements and restrictions on access to the real-time market would only exacerbate the ISO's real-time redispatch problem.) Further, the ISO's inability to address intra-zonal congestion in the forward markets means that the prices in those forwards markets do not reflect the marginal cost of all of the congestion. The price signals are misleading. At best, they tend to encourage scheduling parties to overschedule the grid in the forward market, causing further intra-zonal congestion that cannot be solved until real time. At worst, they create opportunities for artificially creating congestion that the scheduling parties must be paid to relieve. The Commission should therefore direct the ISO to use the voluntary bids submitted in each market to relieve all congestion in each market, and to do so at the lowest as-bid cost.

If the ISO is to be successful in dealing with congestion in the day-ahead forward market, the model it uses for evaluating congestion must reflect the full complexity of the

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[29] If our understanding of the CAISO software is correct, the elimination of this restriction would be easy to implement, as the software relaxes the balanced schedule constraints in the solution process.

grid. Recent "reform" proposals from the ISO and urged by some stakeholders would make this impossible. Instead, they would require the ISO to create and use a simplified "commercial" model of the grid that ignores important constraints. If the ISO used this unrealistic model in the real-time market it could endanger reliability; if it used the model in the forward market, it would guarantee that schedules approved in the forward market could still be infeasible because important constraints had been ignored. There is no escaping the realities of the grid. The ISO should be allowed (required) to use realistic models of the grid when evaluating congestion. Whatever level of modeling accuracy is required to maintain reliability in real time should be applied in the forward markets to ensure feasible schedules and consistent pricing.

3. *An ISO should use locational marginal pricing to price and settle all purchases and sales of energy in its forward and real-time markets and to define comparable congestion (transmission usage) charges for bilateral transactions between locations.*

The Commission will recall that several months before the California ISO and the Commission became preoccupied with the high prices produced by the California market, the Commission had already found the ISO's congestion management system to be "fundamentally flawed" and in need of comprehensive reform. Because the congestion management system implicates many other aspects of the overall market design, the ISO management's process for congestion management reform eventually grew into a comprehensive market redesign process. However, the most fundamental reform needed by the market design and the congestion management process is to get the prices right. The California zonal system is fundamental flawed because it cannot get the prices right. It is time for the California market to solve this fundamental problem by moving to nodal locational marginal pricing.

The Commission appears to have concluded that the ISO can satisfy the need for comprehensive reform of its congestion management system by simply creating a few more zones. The ISO Staff has so far steadfastly maintained that with these new zones, all will be well. It promises to model the system periodically to make sure that its zones remain sufficient and to revise its zones in the future when and if needed. This is the same argument used since the beginning of restructuring in California. It has been an illusion and a license to maintain a fundamentally flawed concept.

The zonal experiment has failed and it must be replaced. It is the source of persistent gaming, infeasible schedules, and poor locational signals. It encourages overscheduling of constrained transmission, fosters market power and muffles the price signals that loads need to respond to high prices. It requires side payments to provide an economic incentive for generators to follow redispatch instructions, but the requirement to make these payments creates gaming opportunities that have been exploited by some generators. It requires constant ISO intervention to offset the poor price signals while forcing the ISO to become increasingly entrenched in centralized resource planning and acquisition schemes. Even when it is not struggling with inadequate supplies, the ISO must still struggle with operating the system, because getting the prices wrong ensures that generators have incentives that will be inconsistent with what the ISO needs them to do to maintain reliability. The experiment has failed, and it is time to end it.

The ISO's most recent congestion management reform proposals anticipate that there might be at least eight new zones (now called "local pricing areas" or "local reliability areas"). The creation of these eight new zones is a positive step, but it should be understood that it will only mitigate, not eliminate, California's recurrent problems with infeasible schedules and intra-zonal congestion. It is important to recognize, moreover, that the creation of eight new zones will likely greatly exacerbate the problems associated with the current form of the adjustment bid based congestion management system. As a result, the ISO Staff has maintained throughout the congestion reform process that it must have additional mechanisms to relieve the new "inter-zonal" congestion between these new zones and the existing zones.

To address this need, the ISO Staff proposed (but the ISO Board rejected) a new two-day-ahead process to select resources in each new LRA. These resources would be required to schedule in the day-ahead market enough energy to ensure that all expected intra-zonal congestion within, and any inter-zonal congestion into each LRA would be relieved. Apparently, the Staff had concluded that reliance on the adjustment bids in the day-ahead market would not be sufficient to relieve all of the congestion, because the market separation rule would effectively limit the number of bids that the ISO could use to relieve constraints at each inter-zonal interface. Thus, an accumulation of flawed rules and their perverse interactions have made the market virtually unmanageable using market processes, forcing the ISO to rely increasingly on command and control measures. More seriously for consumers in the short-run, the combination of eight additional zones and the current adjustment bid congestion management system could pull additional capacity out of the day-ahead markets, increasing the capacity shortage, at a time when there is no excess capacity to subsidize this inefficiency. Retention of the adjustment bid congestion management system and balanced schedule requirements across additional zonal interfaces could give rise to market conditions that would make the outcomes in the California electricity market during the summer of 2000 look good in comparison.

The Commission should not rely on the ISO's assurances that just a few more zones will capture all of the commercially significant congestion within and into California. Such claims have been made before and been proven incorrect. Experience everywhere is that congestion patterns are not stable, and new constraints will arise frequently. Studies of PJM are particularly instructive about the general phenomenon. Last year's constraints are poor indicators of the constraints that are binding this year.[30] And this year's constraints will prove equally poor indicators of the constraints that will be binding next year. As new generation is added at various locations, the congestion patterns will change, and when fuel prices and hydro conditions change, the pattern will change yet again. Trying to predict and lock in the commercially significant constraints, and to define pricing zones around these predictions, is a recipe for getting the prices wrong.

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[30] See, Andy Ott, "Can Flowgates Really Work? An Analysis of Transmission Congestion in the PJM Market from April 1, 1998 to April 30, 2000," September, 15, 2000. A soon to be published extension of the Ott study of the PJM market shows that during 2000, there have been over 130 new binding constraints that have not been binding in previous years.

At a minimum, the Commission should direct the ISO to determine and post nodal prices using locational marginal pricing and to use those LMP prices to settle with all generators. The LMP prices should be used in both the forward and real-time markets operated by the ISO. This will eliminate the need for constrained-on and constrained-off payments for redispatched generations, thus eliminating the "constrained-on gaming" and "constrained-off gaming" that have plagued the ISO congestion management markets. LMP pricing will ensure that generators are paid the market-clearing price at their location without having to withhold capacity or guess the market-clearing price. The strategy of drawing the generators into accepting less than the market-clearing price has not worked, and California can't afford the inefficiency any longer. Efficient nodal pricing will send the right price signals for short-run operations and will reinforce what the ISO is trying to do to manage congestion and maintain reliability. The efficient prices will also provide the right signals for long-run investments, obviating the need for ISO restrictions on new generator interconnections. Getting these prices right is the foundation for relying on market-based decisions.

Appropriately metered loads should also have access to the nodal prices at their locations. Giving the right price signals to these loads will enhance the effectiveness of demand response programs, which in turn will provide more efficient prices and help mitigate market power.

For loads without appropriate interval meters, monthly averaging will still be a necessity, and the value of mapping individual loads to individual pricing buses may be limited. However, the prices charged to these loads should be determined as the weighted average of the nodal prices in their pricing area. The choice of each "pricing area" is a matter of retail rate design. At the highest level of aggregation, the area may be the traditional utility service area. Alternatively, the State can be guided by the ISO's studies, such as those used recently to define new local pricing areas. How these areas are defined, and how often, can be determined by the respective state rate-making authorities working with the ISO.

4. *An ISO should offer tradable point-to-point financial transmission rights that allow market participants to hedge the locational differences in energy prices.*

Once market participants are exposed to locational price differences and point-to-point congestion charges, they will need tradable transmission rights that allow them to hedge these locational differences and congestion charges in order to obtain *ex ante* price certainty for their transactions. Point-to-point FTRs will be necessary to support a nodal LMP system.

The current FTRs are not point-to-point but are rather defined across specific inter-zonal interfaces. With the addition of at least eight more zones (LRAs) within California, the existing FTRs would have become increasingly unworkable. The existing FTRs are essentially a form of financial flowgate rights, and the addition of new zones would force market participants to struggle with the need to obtain multiple flowgate rights for each transaction, given the loops within and around the California grid. The ISO and stakeholders were only beginning to recognize the problems of changing distribution factors last Spring when they were overwhelmed by responding to the high price conditions. No clear solution to this problem has been proposed.

The basic problem is that market participants will not be able to predict the power transfer distribution factors that will apply when the ISO solves congestion in real time. This means that participants will not know in advance how the flows of their planned transactions will disperse across each flowgate (inter-zonal interface) and hence will not know how many flowgate rights to acquire at each flowgate to hedge any given transaction. Essentially, this means that there can be no complete long-term transmission rights in the California market. If the ISO continues its current course, flowgate rights will become, at best, illiquid partial hedges, unless the stakeholders convince the ISO to pretend the rights are full hedges and agree to subsidize the difference. If this happens, the price signals will continue to be wrong, as scheduling parties are encouraged to schedule transactions that are infeasible, because their "full" hedges will have been subsidized against the redispatch costs that their transactions impose on the ISO and other market participants.

The Commission should direct the ISO to redefine its FTRs as point-to-point financial transmission rights. Point-to-point FTRs would remain viable no matter where or how many constraints occur and whether or not "new" constraints arise between the points. They would remain viable no matter how the PTDFs changed.[31] Hence, participants could obtain effective hedges on a long-term basis, without fear that their FTRs would leave them unhedged when grid conditions changed.

Moreover, the Commission should direct the ISO to define FTRs in the form of obligations as well as options and to formulate an auction format in which generators can offer such counter-flow FTR obligations, creating a forward counter-flow market for congestion management such as that currently found in PJM (through its monthly auction) and New York (through both its monthly reconfiguration auction and longer-term auctions). This would be consistent with the Commission's goal of eliminating barriers to efficient forward contracting.

5. *An ISO should simultaneously optimize its ancillary service markets and energy markets.*

Experience in New England and California have now amply demonstrated that the short-run markets for regulation and operating reserves must be fully coordinated with the short-run markets for energy. Ideally, these markets should be simultaneously optimized and their pricing rules made consistent. This will ensure that generators receive efficient market-clearing prices in each market and are neither forced nor

[31] Maintaining each FTR's full hedging ability may require that when there are transmission outages, full FTR funding be maintained even if congestion rentals for a given settlement period fall short. In such cases, the rules could require that FTR funding be reduced *pro rata*, or they could require that surplus rentals from other settlement periods be carried over to fund deficit rentals in other periods. Ideally, transmission owners could be provided a performance incentive for efficient maintenance, while holding them financially responsible for making up any revenue shortfalls in funding the FTRs when lines are down.

encouraged to guess at which market would be the more profitable venue. By optimizing these markets simultaneously, the ISO will ensure that the mix of resources chosen for energy and ancillary services will be the lowest overall cost, given the available bids. By using consistent pricing, generators will be assured that their cost recovery and potential for profits will not be adversely affected whether they are chosen to provide energy, provide regulation or spin, or withheld to provide reserves. If generators are paid consistent market-clearing prices in each market, they will not have to guess the market price or risk bidding mistakes. Instead, generators will have an incentive to bid their marginal costs.

Simultaneous optimization and the associated price cascading are not complicated in principle and can be made to work reasonably well in practice to eliminate perverse bidding and scheduling incentives. Simultaneous optimization and price cascading (and the rational prices they would give rise to) would also permit the CAISO to implement a two settlement system for ancillary services that would avoid paying generators once for reserves in forward markets and again for energy in real-time markets.

6. *The ISO should collaborate in rapidly expanding the capability to include demand side response for energy and ancillary services.*

The least controversial reform of market design would be to implement all the changes needed to allow for demand side response in the face of higher prices. This should include changes both in the wholesale market mechanisms to allow for demand side bids in the day-ahead markets and, for properly metered and controllable loads, in the real-time market. In addition, retail rate designs under the control of the California Public Utilities Commission (CPUC) should be such that customers who choose can see the wholesale price and respond to higher prices by reducing their demands. Prices for usage should be based on the market-clearing level. Retail prices in California that are below the cost of fuel, subsidize electricity consumption in California and raise both electricity and gas prices throughout the WSCC. Any rebates should be in terms of reduced connection costs or in some other manner to break the link between average and marginal rates.

Slightly more controversial, but equally important, would be to introduce the same type of demand response for reserves and ancillary services. Not all reserves are equally valuable, and there has always been some tradeoff between reliability and cost. The traditional procedures that embodied this fact have been replaced by rigid requirements in the new market that have the effect of forcing prices to very high levels, much higher than the reserves or the energy are really worth. The Commission has already addressed this issue in principle in the context of recent proceedings regarding the Northeast ISOs.[32] The same arguments apply to California. The reality is that on its worst high load day, the CAISO is purchasing enough capacity to meet load, provide a large amount of regulating capacity, maintain sufficient 10-minute reserves to cover the

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[32] For ISO New England, see for example, Federal Energy Regulatory Commission, “Order Conditionally Approving Congestion Management and Multi-Settlement Systems,” Docket No. EL00-62-000, June 28, 2000.

largest single generator outage contingency, and maintain what appears to be another couple thousand mega-watts of extra reserves. The couple of thousand mega-watts of extra reserves have value and contribute to reliability, but they may not have sufficient value to treat their acquisition as a requirement at any cost in potential shortage situations. The CAISO should eliminate absolute reserve requirements in excess of the largest contingency and implement a demand curve, reflecting reserve shortages in day-ahead and real-time prices.

TRANSITION RULES

Pointing to the preferred market design is necessary. A Commission direction to the CAISO to produce a filing that filled in the details would be essential if such a design is to be embraced before events force the road to reform to reverse the course towards greater reliance on markets in a return to cost-of-service regulation, or worse. Furthermore, it is essential to have some framework to evaluate any transition steps, if nothing else to make sure that the transition is headed somewhere that we want to go.

However, knowing the eventual market design goal is not enough. As the Commission has recognized, there is an immediate need for action now to mitigate the most serious impacts in the California market.

Furthermore, it is no longer possible to work with a clean slate. The experience of the California Summer of 2000 was too searing. The political process is now well engaged and there are many proposals for reform that work in opposition to each other or move away from the long-term goal. Faced with this reality, the transition must be considered in terms of the degree to which it meets various objectives.

One proffered objective is ensuring the "protection of consumers." Average prices have been judged to be "too high." The immediate steps going forward seek to guarantee reliable service at an average price to the final consumer that is deemed to be low enough, as well as "just and reasonable." Any transition proposal must address the degree to which it envisions, or even seriously risks, a repeat of Summer 2000.

However, more is required if there is any hope of making the immediate steps a real transition, rather than an *ad hoc* implementation of endless experimental regulation. The transition rules must incorporate as much of the critical market design features as possible along with an internally consistent method of moving from the old to the new. Hence, any transition framework should include explicit consideration of how well it is likely to work in a market setting and how it will ensure a transition to an efficient, workable market.

Consistent with the Commission's policy orientation towards a market approach, transition rules should be biased towards reliance on voluntary commercial transactions. The Commission can mandate market rules, structure and incentives. But it must rely on the incentives for performance. This creates problems given the evolution of the California market. The initial decisions peculiar to the California restructuring have produced new ownership patterns and contractual obligations. These embody public policy commitments made in restructuring that may have been ill conceived, but nonetheless have created obligations in place.

Immediate consumer protection is a debate about how to ensure just and reasonable average prices. When prices are high, there are typically two competing explanations. One is the exercise of traditional market power, the other is shortage that produces high prices through simple competition when demand exceeds supply at lower prices. Untangling the mess in California to distinguish the market power effects from the scarcity effects is difficult. Whatever the source of the high prices, there is the same general flow of the money away from customers and towards suppliers. At the margin, we can have different views about the true opportunity cost, but on average some part of the high prices is a rent transfer from customers to suppliers of electricity, suppliers of natural gas, holders of environmental permits, and so on.

By contrast, markets and their magic are all about what happens on the margin. Transition to a market requires that the market design allow for proper signals for marginal decisions and investments. The desired remedies of greater demand responsiveness, new generation entry and greater operational efficiency all build on the idea that the market participants face incentives that reflect the true opportunity costs at the margin.

Immediate adoption of a number of the key elements of the long-term market design would help in the transition. For example, consolidation of the responsibility for short-term market coordination and reliability management under the CAISO would allow other reforms to proceed. Introduction of better mechanisms for demand side bidding on the energy market would incorporate a reform that all agree is necessary to operate a market and moderate price spikes. Introduction of a demand curve for reserves would better reflect the reality of how electric systems have always been operated but translating that into the context of market bidding and pricing. Allowing the CAISO to perform an economic dispatch that simultaneously optimizes the energy and ancillary reserve markets would remove some of the perverse incentives that lead to pricing anomalies and probably reduce the need for capacity devoted to regulation and supporting adjustment bids. All this could and should be done expeditiously, and need not take a long time.

These changes could only help, would not cost much, and would work both in the short run and the long run. The Commission should not hesitate to direct these changes. However, it is uncertain what their short-term and long-term impacts on the wholesale price level would be, particularly given the additional uncertainties involving gas prices, demand and hydro energy supply. Other remedies are targeted directly at lower prices. These other remedies that might be part of a transition are much more problematic. Here we consider the impacts of taxation, price caps, bid caps, and forward contracts.

Taxation

To the extent that the problem in California is perceived to be that small customers are paying market prices, and market prices are too high, any source of money could be used to reduce the financial impact of the customers' bills even though the customers continue to consume the electricity. An emphasis on taxation to ease the transition would put the focus on the money and not on distortions of the market rules. Hence, the use of tax dollars to reduce the impact of higher market prices could have a significant impact.

Paying taxes is not voluntary, but the burden of the increased taxation would be relatively less when viewed as a part of total income rather than of electricity consumption. Other things being equal, the distorting effects of broadly based taxes are generally viewed as less than those that are more concentrated. Hence, taxing everyone is better than taxing only one sector of the industry. Furthermore, the transfer from taxpayers to electricity consumers would probably not be neutral. The incidence of taxes is not likely to be the same as the incidence of electricity consumption. The payments to consumers might be further limited to only those small residential customers and on a basis that is not related too closely to individual electricity consumption decisions.

There is some precedent in California for considering use of general tax revenues to support the transition in electricity restructuring. At a minimum, this would be a way for the state legislature to address directly some of the problems created by the defects in the original restructuring law and policy. Furthermore, to the extent that such revenues are available, this would be an approach to addressing the overhang of costs from high prices seen in the summer of 2000.

On the other hand, if the source of the problem is high costs for gas and emission allowances and capacity shortages, subsidizing electricity consumption in California could largely serve to further elevate gas and allowance prices, while elevating electricity prices throughout the WSCC.

Price Caps

The transition remedy of price caps does not meet the second objective because it does not allow for this operation of the market at the margin. Setting aside the many difficulties of defining, implementing and enforcing price caps, if a price cap can be enforced and is low enough, it will mitigate the average payments by consumers and reduce the flow of money to the suppliers. But the price cap will exacerbate all the other problems that require incentives at the margin. In the end, either this is a policy that requires load curtailment and reduced reliability or, as we have seen, this will drive the CAISO to find mechanisms where it enters the market to make arrangements for supplies that cannot be obtained under the incentives of the price cap. At best, this will put the CAISO in the role of being the vertically integrated supplier of more and more services. At worst, it will undermine the intent and effect of the price cap.

Price caps might be useful as temporary circuit breaker protection to keep peak prices from reaching very high levels, but not as a way of keeping average prices low. Witness the experience of Summer 2000 with falling price caps accompanying rising average prices. In effect a price cap attempts to reduce the flow of money from consumers to suppliers. It seems simple, but this is deceptive. Price caps have a long and unhappy history. The history says that either of two things can happen. One, we eventually abandon the price cap, but only after enduring substantial costs that defeat its main purpose and make the eventual transition to the market even more expensive and more difficult. Or, the regulatory system accommodates more and more ways to work around the price cap to create all the worst features of cost-of-service regulation going forward. The U. S. experience with the former path is best illustrated by oil and natural gas markets in the 1970-1980s. The unhappy experience with the latter path can be seen in electricity markets in the 1980-1990s, which prompted electricity restructuring in the first place. Going back is not the way forward.

Bid Caps

A bid cap is not the same thing as a price cap. If the cause of market turmoil and high prices is the exercise of traditional market power, then it must be that capacity is being withheld from actual use to supply energy or reserves in the final dispatch. Note that this is not the same as asking for and receiving a high price for capacity that is eventually made available in the final dispatch, i.e. being paid the market-clearing price. If the generation capacity is actually used, high prices must be driven by shortage. Traditional market power entails ultimate withholding.

The bid cap approach would be to identify those suppliers that are withholding in this way and impose on these suppliers an obligation to offer most or all of their capacity into the market at no more than a bid cap.[33] This is intended to remove the ability to withhold, but not require any other changes in the market. In particular, if the true market-clearing price is above the bid cap, then the supplier would receive the market price. If the market-clearing price were below the bid, then the supply would not be called because it would not be needed.

By design, a bid cap differs from a price cap in order to make it compatible with a market and market-clearing price. Hence, when traditional market power can be identified, the bid cap provides a targeted means for mitigating market power. And this mitigation procedure would be compatible with the rest of the market design during the transition. Even bid caps can require difficult evaluations of why generation is not available in the market, was a particular outage avoidable, was the unit brought back as quickly as possible, and so on. Hence if the market power were likely to persist in the long-run divestiture might be preferable to continued reliance on bids caps.

Of course, compliance with the bid cap is not voluntary. The justification for the deviation from the principle of voluntary participation would be a finding of market power. Presumably the restructuring rules were never intended nor could be construed as providing a foundation for protecting the exercise of market power. Furthermore, to the extent that the bid cap is not set too low, the bid cap compels no more than that the existing generator surrender its market power, not that it surrender the normal profits it would earn under the competitive market assumption. The bid cap is selective, and does not apply to new entrants or those who do not have market power.

Bid caps could be an important part of the transition rules. They would not be easy to administer, but they would be much easier to administer than would price caps. However, the very attraction of bid caps means that the effect is limited to mitigating traditional market power. By contrast, if the real cause of high prices is high costs and capacity shortage, where demand outruns supply, then bid caps would not significantly reduce the market-clearing price. The market price would still be set at a high level by some entity lacking market power and not subject to the bid caps. Bid caps would be

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[33] The design of a bid cap is easiest in the case of thermal plants. The question of hydro suppliers that exercise market power might require some other mechanism.

effective in mitigating traditional market power; they would not be effective in lowering prices in a shortage condition.

Forward Contracts

An alternative transition tool that has been prominent in other electricity restructuring efforts has been the vesting contract. The basic idea would have been simple had it been applied in the divestiture process. If utilities sold generating plants, the sale would include a contract for the output of the plant at a price deemed "just and reasonable" over the life of the contract, a period set to cover the transition to the full market operation. These long-term forward contracts would a provide dual beneficial effect. First, they would help reduce or remove incentives to exercise market power in spot markets. Second, they would provide an effective hedge for customers to protect them from higher spot market prices.

The impact on market power would arise because the forward contract transfers the economic interest in the output of a generating facility from the generator to the customers. The generator continues to control production, but now the principal incentive would be to maximize the production from the plant whenever the market-clearing price exceeded costs, just the right incentive to support the competitive market. [34]

The impact on customers' average prices through such forward contracts is obvious. The effect would be to recycle the money on average but not on the margin. Market-clearing prices at the margin might be high, but long-term forward contracts for a significant fraction of total load could serve the purpose of mitigating the financial impact of price increases (and decreases) without giving rise to the perverse incentives of price caps. If such contracts were in place, at least for customers deemed small enough to need protection from the transition market, it could be possible to allow for a market design that provides the right incentives at the margin and allows for a self-enforcing exit from the transition stage. This would still not be trivial, however, for if the problem is in part high costs and capacity shortages it would be important to encourage consumers to reduce consumption, and thus important that consumers see the full marginal price for incremental consumption, rather than some average price that would subsidize continued consumption.

The Commission has recommended encouraging (perhaps requiring) utilities to enter into long-term forward contracts. These forward contracts would be quite different from the vesting contracts described above. In particular, the vesting contracts would have been set at the time of sale of the generation with an energy price then determined to be reasonable. The energy pricing would have been mandatory and the implicit value of the vesting contracts would have been reflected in the sale price of the generating facilities. By contrast, entering into forward contracts after the sale of the facilities is a different matter.

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[34] Frank A. Wolak, "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market." International Economic Journal, 14(2), pp. 1-40. (available from http://www.stanford.edu/~wolak) See also, Richard Green, "Britain's Unregulated Electricity Pool," in M. Einhorn (ed.) From Regulation to Competition: New Frontiers in Electricity Markets, Kluwer, Boston, 1994, pp. 73-95.

One proposal suggests emulating a vesting contract by having a contract form, duration and price set in advance and approved in advance by regulators.[35] This suggestion would address the concern of utilities that such long-term contracts be deemed prudent so that the ultimate costs can be recovered in regulated rates charged to customers. While the prudence issue is important, it does not speak to the more difficult question of why suppliers would be prepared to sign such contracts. If the price is set low, it might appeal to regulators, but there is no reason that suppliers should agree to sign such contracts.

If generators did sign such contracts, that might be helpful. However, this could be viewed simply as evidence that the price was high enough to capture by contract the high prices that otherwise would be expected in the spot market. As a means of lowering costs to customers, this would not seem to accomplish the stated objective. It might make prices lower than Summer 2000, but it could also make them higher, even much higher, than the prices of Summer 1999, and it could make them higher than spot prices turn out to be for Summer 2001. On balance, customers might not be better off, and the utilities may be justified in their worries about the *ex post* prudence review.

If the regulatory pre-approved price is set low enough, suppliers may not sign voluntarily. What then? Inevitably there would be calls for using the power of regulation to force generators to sign the contracts. This will present many difficulties. On its face, this approach would abandon the notion of voluntary participation in economic choices. What would be the justification for such compulsion? The justification could not be traditional market power, which could be handled through bid caps. If the problem of high prices arises from high costs and capacity shortage, then use of such mandatory forward contracts would be a rejection of a market approach. In effect, we would be reversing the decisions of restructuring to date and abrogating the deals that had been made in good faith.

At a minimum, it should be recognized that tracking down the deals that have been made would involve a complicated contract chain. Many of the owners of generating plants have already sold some or all of their power forward. Presumably a new mandated obligation to sell it forward again would not be applied to these generators. Would this then mean we would have to trace the ultimate beneficiaries of the forward contracts? The contract chain of further transfers of rights to the hedges could lead to customers already hedged, so we would have to separate these from others. This would require distinctions among the beneficiaries of forward contracts. How would these judgments be made? Without voluntary participation of the parties, how could we untangle the complex contracts and ownership provisions that have evolved? Simply making the pre-approved forward contracts mandatory would not be easy or quick.

One alternative to preserve voluntary participation might be to combine the taxation and forward contract approaches. Suppose there were a class of customers, such as residential and small commercial customers, deemed to be the responsibility of the

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[35] Remarks of Commissioner William Massey (attributed to Professor Frank Wolak of the California Market Surveillance Committee) Energy Bar Association Meeting, Washington, DC, November 17, 2000.

utilities to arrange low cost supplies. The pre-approved forward contract would be defined. This would be defined as a "contract for difference" relative to the locational market-clearing price at the point of load defined by the utility. The utility would decide on the amount of energy to hedge under such contracts. Given the amount, the utility would conduct an auction for the payment that would be required for suppliers to sign the contract.[36] The source of funds for the signing bonus would be from general taxation revenues. Given a decision to have such forward contracts, this would be a means that would allow low direct average prices, market-clearing prices for incremental energy, voluntary participation by the suppliers, and a transition that would be both market oriented and consistent with the move to a more normal market operation. If tax revenues were to be employed, this should minimize the immediate payments required.

This is a way to have forward contracts. But the merits of any forward contracting at this time are far from obvious.[37] Simply put, in a seller's market, pushing buyers to sign long-term contracts runs a greater risk of paying too much than paying to little and is as likely to create new stranded costs as it is to benefit consumers. California missed the window of opportunity of having vesting contracts.[38] The appeal of that foregone opportunity should not cloud our judgment about the realistic opportunities before us.

A Comprehensive Package

Whatever approach is taken to the transition rules, the Commission should continue in the spirit set out in its proposals to provide a comprehensive package for reform. Some of the initiatives, such as improved demand side response, might be desirable no matter what happens. But much of what needs to be done is interdependent.

For example, the beneficial effect of bid caps in mitigating the price impacts of traditional market power might be small if there is still a shortage situation, and a material price impact would depend in large part on the success in developing a demand curve for energy and reserves. In the extreme, without any demand response, bid caps would do little to lower prices in shortage situations.

Similarly, the ability to get a response from suppliers in signing long-term forward contracts will depend in part on how the other parts of the reform package may work. The alternative to some form of negotiated settlement on contracts might be worse for everyone if the effect is simply to ensure the reintroduction of cost of service regulation. At the same time, many or most suppliers might be more willing to enter into reasonable contracts if the rest of the market reforms are included in the package. But

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[36] The echoes of the Biennial Resource Plan Update (BRPU) process are noted. Presumably we could benefit from that unhappy experience with complicated bidding schemes by keeping the form of the forward contracts as simple as possible and reducing the bids to the single dimension of the amount required to sign the contract.

[37] Scott M. Harvey and William W. Hogan, "California Electricity Prices and Forward Market Hedging," October 17, 2000. (available at ksgwww.harvard.edu/people/whogan).

[38] Of course, even if we had replayed history, acquiring vesting contracts at fix low prices might have reduced generator proceeds materially and raised stranded cost recovery requirements.

these suppliers may be unwilling to cooperate if the worst aspects of the market design remain in place and long-term contracts are seen only as a confiscation of assets.

The approval of long-term contracts to preempt *ex post* prudence exposure for what might be relatively high prices would seem to be essential, else the utilities would face the prospect of bankruptcy later to provide others with relief now. Ultimately, there would have to be some resolution that included both the existing overhang of the high costs from the summer of 2000 as well as the high cost that we see going forward.

The sharp change in market conditions presents a major policy dilemma. Looking ahead, the utilities have an interest in advance guarantees of prudence for forward contracts. Otherwise they would face the risk of *ex post* prudence reviews that would apply perfect hindsight to set prices at the "lower of cost or market," reflecting a counterproductive asymmetry in regulation that produced large stranded asset accounts. At the same time, we look today at the existing electricity suppliers who purchased generating assets at costs once seen as high but that now seem low relative to the market. The political pressure is to apply a similarly faulty asymmetric regulation to these suppliers. The dilemma is in finding a rationale for these conflicting tendencies. Any principled argument that applies to one case should apply to other.

Whatever the merits of the argument, the legal situation may be controlling. If the Commission finds that there has been an exercise of traditional market power, then it would be appropriate to determine that the current prices are not just and reasonable. By contrast, if the high prices reflect only scarcity and higher real costs, current prices could be determined to be just and reasonable. Furthermore, if scarcity is the principal explanation of high prices, it would be especially important that the high prices be seen and passed through at the margin in order to provide the right signals for the market. Any reductions in average costs in California should be restricted to infra-marginal transfers that would avoid exacerbating problems throughout the WSCC.

If the legal finding comes down to a conclusion that prices are not just and reasonable, then the Commission may be constrained to a return to cost-of-service regulation if some better solution cannot be fashioned. This finding would change expectations from a continuation of the *status quo* to an anticipation of a prospective regime that would be worse than a comprehensive settlement at this stage. In this environment, a comprehensive package of market reforms, expanded use of bid caps, and negotiated forward contracts might be in the interest of everyone, both customers and suppliers, as preferred to a return to cost of service regulation.

SUMMARY

The Commission has taken a major step in its proposals for California. Its own analysis points in the direction of fundamental reforms in market design. However, this same analysis and the experience of the failed process in California dictate that the Commission travel much further, much faster. The Commission should clarify the responsibility of the CAISO in operating the integrated reliability rules and short-term markets that will be essential for successful operation of an electricity market. The Commission should give quite specific guidance about the design of the future California market along the lines that have worked elsewhere and that reinforce the requirements of Order 2000. At the same time, the Commission should reconsider its use of the soft price cap or any movement to pay-as-bid auctions. The better policy mix for mitigating traditional market power would be a combination of bid caps and forward contracts, but only under conditions where these are part of a comprehensive reform and not simply another short-term fix that creates long-term costs. None of this will be easy, but procrastination or another round of failed reforms in California would be worse.