WHO TURNED OUT THE LIGHTS?

COMPETITION AND CALIFORNIA'S POWER CRISIS

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The stage is set for an antitrust inquisition into the California electric power "disaster." Everyone seems to agree that prices are in some sense too high, but they agree on little else. Do the high prices demonstrate market power, or are they simply scarcity rents from the unfortunate, but not strategic, mismatch of long term and short term supply and demand? And if the high prices do represent market power, does that power stem from poorly designed market rules or from strategic behavior, either unilateral or coordinated?

Across the United States and around the world, governments are trying to apply to the electric power industry the principles learned in the deregulation of other network infrastructure sectors, notably telecommunications, gas, and transport. Electric power presents some new challenges, many of them due to the unique and complex physics of electric power transmission. A common problem is educating customers, particularly households, who are accustomed to ubiquitous, reliable service and have given little thought to what it really costs.

California's lessons about costs and reliability have been painful, and the hunt is already on to identify the cause—and pin the blame. The Market Monitoring Committee of California's transmission-managing ISO says there is significant market power, caused by the market rules.[1]

FERC and its staff appear to believe that some market power is being exercised at demand peaks.[2] Economists Joskow, Kahn, and Puller contend there is market power from strategic behavior.[3] Economists Hogan and Harvey, more cautiously, suggest that there are more innocent explanations.[4]

The most obvious culprit is the regulatory "reform" deal that combined fixed (and reduced) retail prices with volatile wholesale prices—and forced firms offering standard service to depend entirely on that unpredictable spot market. The effect was to discourage new entry by alternative providers and, when market conditions changed, to bring financial ruin to the incumbents. Another obvious cause is the lack of new investment in generation or transmission for a decade.

Other states, and indeed other countries, are watching California's experience carefully and are reshaping their own plans accordingly. Some, concluding that reform in this sector will not work, may retain regulation or government ownership; others, finding that California got the details wrong, will resolve to do better; and still others may conclude that California just had bad luck with weather and gas prices. Some may hold off until new technology decentralizes electric power, reducing the industry's scale and potentially eliminating the need for regulation. All want to be sure they can distinguish themselves from California.

The California reform

California was the first major U.S. jurisdiction to undertake large-scale restructuring in order to promote competition in its retail electric power markets. In 1996 the legislature approved—nearly unanimously—a wide-ranging reform program, which went into effect on March 31, 1998. Customers could choose their own supplier of generated power, while the major investor-owned utilities (IOUs) were required to provide access to their distribution systems so power could be delivered from competitive sources. The IOUs relinquished control over their high-power long-distance transmission lines to the new independent system operator (ISO).[5] To cement the vertical unbundling of the traditional providers, the program also required them to divest much of their generating capacity to new owners. Some of these new owners were out-of-state firms, such as Enron and Duke. In addition, to maximize the scope and importance of the competitive market mechanism, the IOUs were required to sell and buy their power through the newly-established power exchange (PX) and were discouraged from entering long-term contracts.[6]

The IOUs got something valuable in exchange for their willingness to enter this new regime, namely the right to impose a “competition transition charge” (CTC) to recover their “stranded costs,” that is, the historic investments that were approved by the regulators under the old regime but that are unlikely to be recovered in the new, more competitive market. Nationwide, these costs were estimated to exceed shareholders’ total equity in IOUs. Permitting the California IOUs to recover these costs was the price that had to be paid for moving forward without litigation delays. (In New Hampshire, litigation over stranded costs stalled reform for half a decade). To make this arrangement palatable to customers and voters, consumer rates were capped (and indeed reduced). Thus, the market was not fully deregulated. But price regulation was envisioned as transitional, to end in four years (by March 2002) or when a utility had recovered its stranded costs, whichever came first. One of the IOUs, San Diego Gas & Electric (SDG&E), had already recovered its stranded costs—in large part by divesting the relevant assets—and thus was free of the original retail rate cap as of July 1999.

For the first year or two, the market developed about as the proponents of reform had hoped. Wholesale prices had been falling when reform was debated and continued to fall after it was implemented, so the difference between wholesale and (reduced) retail prices was large enough to cover the "competition transition charge."[7] But by 2000 the market took turns that the reformers and market participants had neither expected nor planned for. Demand outstripped supply, and with virtually no reserve left in the system, the ISO had to impose rolling blackouts to maintain system stability in early 2001. Wholesale prices reached extraordinary heights—up to 10 times higher than they had been only a year before.

Rising wholesale prices did not attract enough increased supply, either from imports or from California generators, to bring prices back down. Nor did rising prices persuade customers to curtail their demand, largely because retail prices did not increase for the household (and small commercial) customers whose rates were still capped. Thus the major IOUs had to supply customers with power for which they had to pay much more than they could charge. The IOUs did not have enough funds to cover that difference. Obliged to maintain service and thus to continue incurring losses, they were unable to raise new funding and their reduced creditworthiness made suppliers demand payment up front.

To stanch the financial hemorrhage and respond to the threats of service curtailment, state and federal regulators and lawmakers stepped in. The legislature re-imposed a retail price cap on SDG&E in September 2000, to shield consumers from price increases. Only a few months later, in January 2001, the legislature relaxed the retail rate caps on Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), to reduce their losses. The state also began buying power with state funds and proposed buying the IOUs' transmission assets, to strengthen their balance sheets and to bring this "natural" monopoly element of the system under public control. California has also expedited the process of approving new facilities. At the federal level, FERC permitted the IOUs to bypass the PX and buy power directly from generators (including their own affiliates)[8] in order to fulfill their supply obligations. And DOE directed other suppliers, using powers given by Section 202(c) of the Federal Power Act), to continue selling power (and natural gas fuel) to the IOUs despite the risk of non-payment. FERC determined that, when supplies are tight, prices above an upper limit could not be considered "just and reasonable"[9] and has begun to investigate whether some of the "unexpected" shutdowns represented a supplier withholding capacity to drive up the price of power from its other generating units. The story is still unfolding; as this article went to press, the California PUC was deciding to increase retail electric rates substantially.

Causes of the Crisis

Some of the causes of the California crisis appear to be short-term, unexpected accidents, while others, which have developed over the long term, should have been foreseen and taken into account.

Unusual weather affected both demand and supply. A hotter than normal summer, which required more power for air conditioning, was followed by a colder than normal winter, which required more power for heating. In addition, drought in the Pacific northwest, a traditional source of imports into California, reduced the supply of power from hydroelectric plants there (and dramatically increased its price). The electric power system should have the capacity to deal with short-term, year-to-year variations in weather, though.

But demand had also been increasing over the long term, a fact that became clearer after the reform program was in place. While California was debating reform in the mid-1990s, demand appeared stagnant. One argument advanced for reform was that it would promote economic development by reducing California's unusually high retail prices. Reform may have been a victim of its own success, if it indeed encouraged growth and thus more energy consumption. For whatever reasons, retail sales increased 11 percent from 1990-99, and the growth in demand after 1996 appears to have taken some planners by surprise.

Higher input costs were part of the problem, too. The cold weather increased the demand and the price of natural gas, which was already in shorter supply because exploration had declined in response to low gas prices a few years earlier. California gas supplies were also reduced because of an accident on a major pipeline in the Southwest. Gas prices that had held steady around $5 per MMBtu, sometimes reaching $10, spiked up to $50. Another cost factor of particular importance in California is environmental compliance. The prices for tradable permits for NOx emissions increased dramatically, from about $1-2 per pound to $35 by August 2000, high enough to affect electric power prices as higher-polluting marginal units came on line. And some plants may have reached their allowed annual emissions limits because of unexpected demand in mid-2000.

Wholesale supply did not grow and bring prices down, in part because many generating units had been taken out of service. Outages for repairs that had been scheduled for the normally lower-demand winter period coincided with unusually cold weather. Some other plants were taken out of service unexpectedly—and whether these withdrawals were strategic moves to keep prices up is one of the points of debate. (Even systems that have not experienced California's problems, such as the

PJM system in the Middle Atlantic states, have observed an increase in plant down-time since the markets were opened up. Some attribute this increase to high penalties against capacity that is bid into the system but then does not perform). California's total net available capacity (in summer) is about 53,000 megawatts, and when the supply crunch was at its worst in winter 2001, about 20 percent of capacity—10,000 megawatts—was out of service because of planned or unplanned outages.

Even when all the capacity is on-line, California may still face problems, for despite the increasing demand, no new major power plant had been put on line in California for over a decade. Instead, generating capacity declined 2 percent from 1990 to 1999. The state has scrambled to grant siting authority for some new generating plants and speed up the approval and completion of others, and projects now in progress may ease the shortfall. But most of this capacity will not come on line for at least two more years.

The shortage could not be relieved by bringing in power from elsewhere, either. California is a net importer, relying on about 11,000 MW of out-of-state capacity. Since 2000, Northwest hydroelectric capacity has been limited by low water levels. Between 1999 and 2000, the rate of imports dropped nearly 50 percent.[10] Even if more out-of-state power had been available, there might have been problems delivering it, for no new transmission capacity has been installed for years.[11]

Finally, retail customers did not reduce demand. Despite the high wholesale prices, retail rate caps remained in effect, so many residential and small commercial customers got no price signal to reduce consumption. And even without the caps, the traditional regulatory practice of averaging rates over several months would have diluted the wholesale price signals. Only real time metering would convey fully accurate price signals.

The 1996 reform deal's effect on the crisis

Many of these problems and their causes are direct consequences of defects in the 1996 legislative "grand bargain". The combined effect of provisions that were intended to compensate utilities, mollify consumers, and promote competitive entry was a set of regulatory constraints that discouraged or prevented market-based responses to unexpected events.

The stranded cost deal required continued price regulation while the IOUs included the CTC in their distribution rates. Because operating costs appeared to be declining, the plan was that the retail price could be fixed and increasing margins would pay for the stranded costs. The reform plan was conceived when wholesale prices were about $30 per MWh and retail prices were about $60 per MWh. As long as such conditions persisted, the CTC was serving its purpose. But in June 2000, the (average weighted) wholesale price jumped to about $130, more than wiping out any margin for further stranded cost recovery, and it did not fall below $100 until mid-2001. Indeed, by December, it exceeded $350, or about 10 times the level that the reform plans had anticipated. The magnitude of these price increases may have spooked the legislature into reneging on the deal.[12] It has not helped that the utilities have in effect passed the CTC funds along to their shareholders rather than retain them as a reserve to deal with unusual market conditions.

Moreover, the CTC arrangement did not leave enough profit headroom to attract and keep retail entrants (whose customers still had to pay the CTC to the distributor, even if they bought power from a new entrant). Few suppliers tried to enter the retail markets, and several firms that did try at first dropped out later. Thus there was no push to build capacity to supply new retail entrants,. And the IOUs, which were divesting generating capacity and uncertain about their long-term load obligations, did not add capacity either.

The other side of the stranded-cost deal was that retail prices would be frozen at their 1996 levels. Moreover, the price ceiling for residential and small business customers would be set 10 percent below the previous regulated price, so that consumers could obtain an immediate, direct benefit from the restructuring program.[13] Freezing prices stifled competition, insulating consumers and delaying retail-level entry. Customers have had little incentive to respond to high wholesale prices by reducing consumption or by managing risk through hedging. Retail-level demand remains very inelastic, especially in the short run. With average pricing still the rule, there is little capability to respond to price changes in real time. Would-be entrants who would offer more efficient real-time metering and controls have met customer indifference, as well as suffered the high costs in customizing new service. Distributed generation by micro-turbines or fuel cells, which could be another way to for customers to respond to high prices, is not yet significant enough to make a material difference, in part because connection standards for these small on-site units are still being established.

Reform measures to protect competition prevented market responses

Many aspects of the reform plan were intended to promote and protect competition. Unfortunately, side effects have prevented normal competitive-market responses to changing conditions. The major IOUs were required to divest some of their generating assets, both to reduce concentration at that stage and to reduce vertical integration and the temptation to engage in anti-competitive self-dealing.

Requiring divestiture reduced the risk of market power; however, it also prevented the regulator from returning to cost-based price regulation of the divested generating capacity.

The major IOUs were also required to rely heavily on the spot-market PX, to assure that the PX market was robust and efficient, rather than too-thinly traded, and to spread the fixed costs of establishing the PX over a large volume of trades. The IOUs were required to bid the output from their remaining generation capacity (chiefly nuclear and hydro plants) into the PX, they were required to obtain power to meet their "provider of last resort" obligations on the PX, and they were not permitted to enter contracts for continuing service (vesting contracts) from their divested generating plants. But the spot market proved inadequate to deal with the changing conditions that brought on the crisis. In effect, the market rules prevented the IOUs from hedging, and thus severely constrained their ability to insulate themselves from risks of change in market fundamentals. Reform programs in some other jurisdictions have permitted distribution companies to enter continuing supply contracts with the buyers of their divested generating assets. Such continuing relationships reduce the scope of the market that is potentially available to other generation suppliers. But they may also support some assurance of continuity of service as new relationships develop. In late 2000, FERC removed the requirement that the IOUs depend only on the PX. Most supply arrangements then shifted to bilateral contracts, and the PX filed for bankruptcy.

Some of the operation and market rules that California adopted may have contributed to the supply crunch. In theory, California used a one-price rule, under which all the generators whose bids were accepted would be paid the market clearing price. In a one-price system, a generator has incentives to bid at its marginal cost, which leads in turn to "merit dispatch," with the lowest cost units coming on line before the higher cost units. But practice, some of the more detailed rules may have turned California into a “pay-as-bid” market, under which generators were often paid the price they offered to accept, rather than the market-clearing price.[14] This method can lead to inflated bids and major inefficiencies, as inaccurate guesses lead to dispatching out of merit order.[15]

The transmission system rules have contributed inefficiencies, too. California is the only ISO that uses zonal pricing, which does not reflect differences in congestion costs within a zone. Transmission prices should respond to changes in marginal costs, including the effects of congestion, in part to reveal where to target investment in new transmission capacity and facilities. Even though FERC reports that intra-zonal congestion did not contribute materially to the problems in the summer of 2000, inefficient use of the grid cannot make things better. FERC has required that the California ISO use locational marginal pricing as a basis of comparison in its proposals to modify the zonal system. In addition, California’s transmission pricing system produces some of the “pay-as-bid” aspects of the generation pricing system.

The ISO, managing transmission, and the PX, dealing in power, are distinct institutions, but they serve complementary and even overlapping functions. Separating them, and risking differences in policy and pricing, may have been a mistake. Transmission and generation can be substitutes, as increased demand could be met either by turning on additional generators or by bringing in power from more distant ones. The ISO even handles some aspects of power generation, for the ISO is responsible for the “ancillary services” and reserve power supplies that are needed to maintain system stability as demand and supply fluctuate.

In addition to problems of co-ordination, the ISO and PX have had problems of governance. Stakeholder representation has sometimes deadlocked board decision-making. FERC and the state have taken drastic action to replace the old ISO board, which was designed to represent multiple interest groups, with one that is more managerial. This may have been a change for the sake of change, as debate continues about whether the board's new composition represents an improvement.

Continued price regulation probably encourages suppliers to divert or even export power to other states where they can get a higher price (or more certainty of payment) from distributors that can charge higher downstream prices. And uncertainty about the extent of continued regulation may have discouraged investment, a condition that is likely to persist at least until investors can be more sure of what the post-regulation market will look like. Changing the pricing scheme on the fly, especially by re-imposing wholesale rate caps, certainly increases the disincentive. Regulatory uncertainty may be partly responsible for the lack of investment in new generating capacity and the lack of progress in expanding transmission and unblocking bottlenecks.

Does the shortfall represent exercise of market power?

Severe transmission constraints create load pockets in which supply is more highly concentrated. Some of the shortfall may be the direct result of firms exploiting market power in these conditions by withholding supply. One reason for requiring the IOUs to divest generating assets was to reduce concentration and increase competition at that stage. Although a move in the right direction, it was necessarily a crude approximation at best, as overall concentration based on total capacity may not be a useful indicator of competitive conditions. Rather, competitive conditions depend on load and costs in particular regions at particular times. Different periods represent different product markets, in which different plants would set the market-clearing price. The supply curve is typically very steep at the highest demand levels, so small shifts in supply can lead to dramatic changes in price.

A recent econometric analysis[16] concludes that the prices and supply patterns observed in California in the summer of 2000 cannot be explained completely as competitive market responses to such factors as higher gas prices, increased demand, reduced power imports, and higher prices for emissions permits. Rather, during that period "there is a very significant gap between actual market prices and competitive benchmark prices that take account of these market fundamentals." Moreover, the authors find evidence implying that high prices reflect supply withholding, by generators or marketers. That inference is supported not only by the benchmark price analysis, but also by analysis of capacity withholding, showing "a substantial gap between maximum levels of generation and observed levels in those hours identified as scarcity hours," a gap that is not explained by requirements for ancillary services or by reasonable estimates of forced outages. They conclude that, "while our analysis of withholding is necessarily limited by the data available to us, there is sufficient empirical evidence to suggest that the observed prices reflect suppliers exercising market power."

To be sure, other economists doubt that the available information is accurate enough to support definitive inferences. But if the shortage was due in whole or in part to the exercise of market power, the question that arises is whether to address that by statutory intervention, re-regulation, or competition law. And that choice depends on who did what. Straightforward collusion would be the easy case for competition law, if it could be proven. But if the shortage was caused by the action of a single firm taking advantage of market power, or if it represented a pure oligopoly response of a small number of firms understanding that each would individually profit if all withheld output, without communicating their plans or expectations to each other and without reaching an agreement and commitment to that course of action, U.S. antitrust law would provide no remedy. The most antitrust could do would be vigorous merger enforcement to prevent the temptation from getting worse. The Clinton administration proposed to give FERC the power to assess and apply structural remedies for the market power resulting from mergers that were permitted when policy makers assumed that regulation would continue to constrain market power indefinitely. Most proposals about electric power regulation since the last election do not include this feature. Instead, FERC has sought to address market power under its authority to ensure that rates are “just and reasonable,” by ordering refunds of high bids in emergency peak demand periods.

Implications

California’s troubles obviously have implications for deregulation or reform elsewhere. States that are in the process of implementing retail choice are watching California carefully to make sure they do not catch the same bug. But change has not stopped. For example, Texas is proceeding with its plans, and the retail choice program in Pennsylvania seems to be going well. Wisconsin, by contrast, is holding off retail competition until it gets its infrastructure right. A few states, such as Colorado, have given up on retail competition, having concluded that remedies for the market power problems would be difficult to implement and politically intractable.

California’s experience is resonating farther afield, too, as many countries are taking a second look at their reform plans. An EU directive requires its Member Sates to open up their systems to permit retail competition, but there is still little cross-border energy trading and little retail competition or choice, in an industry setting traditionally dominated by national-scale integrated public monopolies. Markets have developed most at Europe's geographic edges, in the Nordic countries (where an integrated pool has been in operation for several years) and the UK. Markets are being launched in Amsterdam, Madrid, and Warsaw. But the California problems, following on the UK's post-liberalization experience of market power in generation, are supporting advocates of a cautious approach.

Systems in the United States that have used different market rules have avoided some of California's problems. In Pennsylvania, where the stranded-cost recovery period is longer, the resulting price structure is more attractive to retail entrants and the rate of customer switching is much higher than in California. In the PJM market in the mid-Atlantic states, most of the "market" rules contrast with California's. Hedging is allowed, a one-price rule makes scheduling more efficient and stable, locational marginal pricing is used for transmission, and the ISO and the PX are combined to simplify co-ordination.

FERC's proceedings to encourage the formation of larger-scale transmission management structures ("RTOs"), in order to expand the scope of markets and permit competition at greater range, are taking on greater urgency. The optimal size and scope of an integrated transmission management system is still being worked out by experiment. Federal legislation to provide a general framework for the new competitive market system is still on the drawing board, though. And FERC's original orders setting up the open-access system await a ruling by the Supreme Court.

What next for California?

Hindsight shows that the major oversight in the California reform was the assumption that wholesale costs would perpetually decline. The effect of that error was aggravated by the unforeseen consequences of market rules, lack of investment in generation and transmission, a stranded cost recovery method that stifled retail entry, and lack of demand elasticity. The high priority that the IOUs put on recovering stranded costs and the political leaders' interest in setting up competitive market institutions as fast as possible led to arrangements that handicapped the major IOUs with inadequate allowance for ongoing supply obligations, no ability to hedge, and no capacity to deal with reversal of the cost trend.

Is there any way to fix the situation? First, the demand side must be part of the market. If demand is almost entirely insensitive to price, market power is likely to appear in some time periods, particularly those of peak demand. Making demand responsive will require that retail customers have timely and accurate signals that reflect wholesale prices. Important components will be real time metering and de-averaging of retail prices. Second, decisions must be made without further delay about new generation and transmission siting, to relieve the supply shortfall. The urgency of the short-term problems may force changes before the causes are well understood. Some of the current proposals, such as accelerating decisions about siting new generation and transmission, encouraging real-time metering, and clarifying connection standards and pricing for onsite generation, would be reasonable improvements regardless of the ultimate diagnosis.

There is enough comparative experience now to identify choices that went wrong in California. Market rules must support efficient operation. The transmission system operator must have workable, efficient policies about congestion and expansion, and its governing structures must support efficient decision making. Rules to recover stranded costs must not discourage entry. Distributors and suppliers must be able to hedge and enter long-term contracts, especially if they are exposed to long-term or supplier-of-last-resort obligations. Market structure must not encourage market power. And the system must have some play in the joints, some adjustment mechanisms to respond to changes in cost and demand. Prayers for ample rain, cool summers, and warm winters are not often answered.

California's reform experience confirms the wisdom of making haste slowly. It would have been prudent to take steps one at a time, to phase in the new institutions and other changes, rather than drive to a single, grand—and flawed—political bargain. Fixation on one aspect of the deal, stranded cost recovery, may have distracted attention from designing the other institutions carefully. The experience shows the continuing educational value of a federal system, of decentralization, power-sharing, and policy experimentation. No doubt many California consumers feel like laboratory rats right now. For the rest of us, the odds of getting retail competition right in the long run may be appreciably higher, because we have learned from the problems and successes of California and the other pioneering states.

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[1] Market Surveillance Committee of the California Independent System Operator, Frank A. Wolak, Chairman,Report on Redesign of California Real-Time Energy and Ancillary Sercices Markets, October 18, 1999.

[2] U.S. Federal Energy Regulatory Commission, Order Directing Remedies for California Wholesale Electric Markets. Docket Nos. EL00-95-000, et. al. December 15, 2000.

[3] Paul L. Joskow & Edward Kahn, *A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000*, AEI-Brookings Joint Center for Regulatory Studies, Working Paper 01-01 (Jan. 2001); Steven L. Puller, "Pricing and Firm Conduct in California's Deregulated Electricity Market," (January 2001),

University of California Energy Institute working paper PWP-080.

[4] *See* Scott Harvey & William W. Hogan, Issues in the Analysis of Market Power in California, (working paper, Oct. 27, 2000; availabe at www.whogan.com), who describe how the effect resulted from the ISO's "rational buyer" approach to securing ancillary services and the means of selecting generators to provide real-time intra-zonal congestion management. See also Scott Harvey & William W. Hogan, On the Exercise of Market Power through Strategic Withholding in California (working paper, Apr. 24, 2001; available at www.whogan.com).

[5] FERC Orders 888 and 889 also sought to establish "open access" to transmission service through rules controlling behavior. Continued concerns about discrimination in access to transmission for wholesale power transactions led FERC to encourage the formation of ISOs, such as California's FERC Order 2000 moves this process forward for the entire nation.

[6] Hedging was frowned on as unlikely to be considered prudent, after the natural gas industry's experience with unfunded commitments in the 1980s and the electric power industry's experience with uneconomic contracts under PURPA

[7] The rate reductions were covered by selling "deferred revenue" bonds, which will eventually have to be paid through a surcharge on distribution fees.

[8] Despite the divestiture of fossil-fuel plants, the IOUs still have some nuclear and hydroelectric generating capacity.

[9] During type 3 emergencies, FERC has decreed that prices above the marginal cost of the conventional single cycle gas units at the margin ($273 for January 2001, $400 or more for February) are not just and reasonable. Commissioner Massey's dissent questions why FERC claims market power couldn't be present in other periods, and favors using $150 as the screen.

[10] Joskow & Kahn, *supra* n. 3.

[11] Within California, long-distance transmission between north and south suffers from a capacity constraint on the main tie line ("Path 15"). This long-standing bottleneck, which California is now considering relieving, makes it difficult to move power between parts of the state and in some periods results in a large and persistent difference in wholesale power prices between northern and southern California.

[12] Even though SDG&E no longer imposed the CTC, the legislature re-imposed a cap on SDG&E's retail prices in September 2000. The statute did guarantee that SDG&E would be able to recover the resulting losses later. Perhaps because of this guarantee, SDG&E did not suffer the same credit crisis as the other big IOUs.

[13] The utilities could sell bonds to cover the revenue lost.

[14] See Harvey & Hogan, *supra* n. 4.

[15] The market rules problems are documented more fully in the reports of the market surveillance committee of the California ISO. A blue ribbon panel recently assembled by the California PX strongly recommended using the market-clearing-price approach.

[16] Joskow & Kahn, *supra*, n. 3.