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Publication Date
2002-08-01

CSEM WP 103

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August 2002

This paper is part of the Center for the Study of Energy Markets (CSEM) Working Paper Series. CSEM is a program of the University of California Energy Institute, a multi-campus research unit of the University of California located on the Berkeley campus.

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The History of Electricity Restructuring in California

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Abstract

This paper aims to provide an objective history of electricity restructuring in California from the mid-1990s to the immediate end of the "California Energy Crisis" in June 2001. We discuss the restructuring debate that led to the restructuring law (AB1890), and describe how the new structure worked after it took effect in April 1998. We discuss the course of events during the crisis, and factors contributing to it, including the supply-demand balance in California and in the West, rising gas prices, the complexity of the market design, market power, and the regulatory decision to cap retail but not wholesale prices.

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I. Introduction

The purpose of this article is to provide a factual account of the California electricity restructuring from the beginning of its planning in the early 1990s through 2001. Widespread attention has been focused on California owing to its "crisis" of 2000-2001. The period referred to as the crisis began with unexpectedly high prices in the summer of 2000 in the San Diego area, and became statewide in early 2001 as the state experienced rolling blackouts, prices over 10 times usual levels, the bankruptcy of one of its major utilities and near-bankruptcy of another, and state takeover to become the major purchaser of electricity from generators.

At the time of this writing, the visible signs of crisis appear to have abated. There have been no further rolling blackouts since the spring of 2001. Spot prices for California electricity in the fall 2001—spring 2002 period have remained quite steady at their pre-crisis levels of approximately $30 per megawatt-hour. Yet whether the problem has been solved, and the future structure of the electricity sector, remain unsettled issues. We provide this history to help guide the analyses, interpretations, and recommendations that we hope will help foster a productive settling of the issues.

We begin with a very brief *background* of important electricity facts that preceded the serious discussion of electricity restructuring that began during the 1990s. Then we turn to the *planning period*, by which we mean the discussions and debates leading to the regulatory decision to restructure the industry. This is reviewed in three phases. The first official set of restructuring discussions and hearings culminated in the 1993 release by the California Public Utilities Commission (CPUC) of a document known as the "Yellow Book." The next phase is from the release of the Yellow Book until the CPUC announced its intention to restructure the industry in April 1994, described in its document referred to as "The Blue Book." The third phase covers the period from April 1994 until December 1995, at which time the CPUC issued its Policy Decision to move ahead with restructuring.

At this time, the setting for action begins to shift to the state legislature. The *legislative period* of our review is from December 1995 to September 1996, at which time state legislation AB 1890 was enacted to legalize the restructuring. Following the legislative period is the *implementation period*. Implementation began immediately following the passage of AB 1890, with stakeholders working out the details of how day-to-day operations would be handled within the new framework required by the legislation. The actual opening of the restructured markets took place in 1998. The new markets operated with apparent success and some acclaim until the beginning of the crisis in the summer of 2000. We then turn to *the crisis stage*. We review the numerous events associated with the collapse of the markets—mindful that there remains controversy over the extent to which any of these were causes, rather than symptoms. We also review the actions aimed at restoring order. Finally, we review the most recent period in which the market has at least temporarily stabilized, although it is widely recognized that the stop-gap institutional structure currently holding things together must be replaced with a more permanent structure.

II. The Background Context for California's Electricity Restructuring

There are a number of salient facts to keep in mind about the situation in California that led eventually to its decision to restructure its electricity industry. We note first that, at the time the restructuring discussions began, electricity in the United States including California was provided to end users by monopoly enterprises: either private, investor-owned utilities subject to state rate-of-return regulation (and federal regulation for any interstate services), or public enterprises controlled at their local or regional levels. These monopoly enterprises obtained the electricity to service end users primarily through their own generators carried over their own transmission lines—the so-called vertically integrated utility.

It was not uncommon, however, for these monopolists to purchase small amounts of power from other entities, typically neighboring utilities, in bilateral transactions. Some of these purchases were spot transactions to meet unusual situations (e.g. unusually high peak demand, or an unexpected plant outage). But other purchases were arranged through forward contracts of widely varying lengths (several days to more than 20 years); these typically occurred as a way to take advantage of excess capacity in one area (e.g. a plant built to service an expected demand increase that did not fully materialize, or a plant that was fully-utilized in, say, the winter season but not other seasons) in order to meet demand in another area in a relatively inexpensive way. No centralized market existed to facilitate these transactions, because of their regional nature and the small number of them.

One important exception to the arrangements described so far was private, independent generation stemming from the 1978 federal Public Utility Regulatory Policies Act (PURPA), and magnified by the supportive response of the CPUC to it. PURPA was a reaction to the oil crisis of the mid-1970s, leading a confluence of energy-conservation and environmental forces to support increased co-generation and use of wind, solar, biomass, and geothermal energies to generate electricity. These producers, called qualifying facilities (QFs), were limited to be small (<80MW) and could only sell for resale (i.e. to utilities).

There was a tremendous response in the 1980s in California to the PURPA legislation, aided by the generosity of CPUC-required standard contracts that the utilities made available to potential QFs. By far the most popular of the standard contracts were those involving long-term commitments. For example, the most commonly signed contract was Interim Standard Offer #4 approved by the CPUC in September 1983. This contract offered new QFs capacity payments for 20-30 years as well as fixed-price energy payments for 10 years that rose exponentially from about 5 cents per kWh to over 12 cents. These terms were intended to reflect the avoided cost from conventional utility generation and assumed that the high oil prices of the early 1980s would continue; instead, oil prices fell, making QF energy through this contract relatively quite expensive.

The contract proved so popular that by 1985 there were over 15,000MW of QF capacity under contract (not all of which would be built) and the CPUC, "fearful that there is no end in sight to the subscription," suspended it in April 1985 (CPUC, 1993, Ch. 5, p. 66). Nevertheless by 1992, enough new small QFs had come on line to provide 9500MW of capacity, equal to more than 4 Diablo Canyon nuclear plants (2190MW). During 1991, the QFs provided 26.2% of the total energy needs of California's three investor-owned utilities.

The utilities showed that they could now handle the control problem of balancing supply and demand on the grid even with many independent power producers. Thus it was demonstrably no longer the case that control of the grid required vertical integration of generation and the transmission system. Furthermore, the development of QFs left no doubt that the development of independent generation sources is highly feasible, and that this source of supply can add significant new capacity over a reasonable number of years. The later restructuring discussions did not highlight the long-term nature of the contracts that induced this substantial supply response. That is, the QF experience did not provide any evidence about whether and how quickly competitive spot markets could induce new independent power producers; it demonstrated that the issuance of long-term bilateral contracts encouraged by the CPUC could do so.

Another important aspect of the decade before the beginning of serious restructuring reports was the lack of any significant new generation proposals by the utilities. From 1983-1991, just over 7000 MW of new utility-capacity came on line. However, virtually all of this was due to the completion of nuclear plants under construction in the 1960s and 1970s, with a troubled financial history of cost overruns that were multiples of the original estimates, much of which the CPUC would not allow to be recovered from ratepayers. Thus the utilities had little interest in undertaking any significant new generation investments themselves under the existing regulatory compact. From their perspective, they could at best break even and then only if all of their expenses were judged prudent and reasonable by the CPUC. There was no upside potential and considerable downside risk.

Beginning in 1989 the CPUC tried to encourage more independent generation through its Biennial Resource Plan Update (BRPU). In the BRPU the utilities were to specify amounts of new generation that would be needed in the future and use a competitive process to contract with independent power providers to build plants and supply some of this power. This solicitation was known as the Final Standard Offer 4 (FSO4) auction process. However, the process initially was plagued by disputes about appropriate contract terms, and then attention became focused on the restructuring alternative; the BRPU was never successful.[1] Thus while California had ample generation resources at the time of restructuring discussions, the ability to adapt these resources to changing circumstances over time would depend on any new mechanisms put into place.

[1] The BPRU was suspended in February 1995 when the Federal Energy Regulatory Commission ruled on a technicality that California could not require its utilities to enter into long-term contracts with the renewable power producers.

Finally, there is the matter of rates. In 1991, the average electricity rates for California's investor-owned utilities ranged from 9 to 10.5 cents per kilowatt-hour. This was 30-50% above both national average rates and the competitive cost of new supplies (CPUC, 1993, Ch. 7, p. 122).

These factors help explain why, from the perspective of 1992, conditions encouraged a consideration of electricity restructuring. Rates were too high, and the idea that the entire industry had to be vertically integrated was demonstrably false. Other sectors of the economy, like trucking and telecommunications, appeared to be benefiting from less reliance on traditional regulation in favor of more reliance on market forces. With the economy in recession, and the state looking for opportunities to bolster its competitive climate and attract new industry and jobs, it seemed eminently sensible to at least consider the idea of electricity restructuring at this time.

III. The Planning Period

A. The Yellow Book Phase (September 1992—February 1993)

In September 1992, the CPUC directed its Division of Strategic Planning to undertake a comprehensive review of its regulated electricity industry and to "explore alternatives to the current regulatory approach in light of the conditions and trends identified" (CPUC, 1992, p.17). This review culminated with the release of the document referred to as "The Yellow Book" on February 3, 1993, in which the Division recommended regulatory reform that would increase reliance on market forces (CPUC, 1993). It should be noted that this report followed closely passage at the federal level of the Energy Policy Act of 1992, which set forth a long-term vision for the nation's electric services that embraced greater reliance on competition and market mechanisms.

The Yellow Book was intended to serve as the basis for dialogue between all interested parties (e.g. the utilities, consumer groups, independent producers) and the CPUC about regulatory reform. While it recommended market-oriented reform, it left the door wide open as to how extensive such reform might be. In particular, its recommendations were that four alternative strategies deserved serious consideration. Three of these strategies were far more modest than the actual reform eventually enacted. Strategy A was termed "Limited Reform" and largely retained the existing cost-of-service regulation, modified by increasing the frequency of rate cases to be annual while deleting some balancing accounts and rate adjustment mechanisms, and using a performance-based mechanism for regulating the utilities' natural gas purchases used to generate electricity. Strategy B was "The Price Cap Model" along the lines of that used to regulate California's telecommunications industry. Strategy C was "Limited Customer Choice", modeled after the CPUC's regulation of the natural gas industry. Most customers would remain in the "core" where regulation is largely unchanged, but other customers (presumably the largest) could opt to be in the "non-core" in which they arrange service from an alternative provider who procures and has "open access" to transport electricity on the transmission system.

Strategy D was the "Restructured Utility Industry", in which the utilities divest all of their generation, become common carrier transmission and distribution companies, and compete with alternative energy service providers in an open market to win customers and procure generation services for them. This general strategy turned out to be closest to the intent of the specific reforms undertaken later on.

B. The Blue Book Phase (February 1993—April 1994)

On April 20, 1994, after numerous proceedings and hearings, the CPUC issued its Blue Book—the Rulemaking proceeding in which it announced its intention to restructure the industry, and to begin the process of deciding formally how to go about it (CPUC, 1994). In other words, the CPUC had decided that it wanted to pursue Strategy D from the Yellow Book, to create a future in which customers would have choice among competing generation providers and in which traditional cost-of-service regulation would be replaced by performance-based regulation (CPUC, 1994, p. 1).

The issuance of the Blue Book marked the beginning of a formal process to consider how the CPUC restructuring vision could be accomplished. The CPUC was very clear in describing a timetable of future hearings and investigations that would resolve these issues and lead to direct access of California electricity consumers to “generation suppliers, marketers, brokers and other service providers in the competitive marketplace for energy services” (CPUC, 1994, p. 12). Specifically, the CPUC intent was to make direct access available by January 1, 1996 to the largest customers, defined as those receiving service at the transmission level of 50 kilovolts or greater, and by January 1, 2002 to all customers. No customers would be forced to participate in direct access; they were to have the choice of continuing to receive bundled service from the utility (the traditional integrated package of generation, transmission, and distribution services), or choosing a direct access provider. The utility would be obligated to provide transmission and distribution services on a nondiscriminatory basis to direct access consumers.

One of the key issues raised in the Blue Book for later resolution, foreshadowing future events, was the importance of an electricity spot market and whether the CPUC should explicitly foster its development. The Blue Book found the United Kingdom's spot market, known as the Pool, to be "particularly appealing" for its half-hourly price signals that serve as a visible guide to consumer decisions about energy services and generator decisions about constructing new plants, as well as providing for economic dispatch of the existing generation sources (CPUC, 1994, p. 25). It recognized the desirability of bilateral contracting in a developed marketplace to handle the diversity of transactional demands and risks, but in the market formation stage it viewed such contracting as a possible threat to the system reliability it thought the Pool model offered. It recognized that in other markets the design and operation of a spot market as well as other market tools are left to the marketplace itself, but asked parties to comment on whether the CPUC should first ensure a UK-style spot market in order to foster the development of competition.

Another key issue raised in the Blue Book for future resolution was whether or not the utilities should be ordered to divest themselves of their generating plants. It stated that it was not convinced divestiture was necessary for consumers to achieve the benefits of competition, and pointed to its experience in the natural gas and telecommunications industries. It suggested, as one possible alternative, that utilities could be barred from providing generation services only within their own service territories. Nevertheless, it did note that any utilities choosing to retain generating assets would necessarily be subject to a much higher degree of regulatory scrutiny than those choosing to divest. It asked parties to offer comments on the divestiture issue.

The Blue Book raised other issues concerning the intended restructuring. It recognized that some of the utility's generation assets were uneconomic (market value in a competitive generation setting less than remaining book value that would be paid by ratepayers under the old regulatory compact), and others were not. It stated that any uneconomic net of these asset values, the so-called "stranded costs," would be identified in proceedings and then recovered by the utilities through a non-bypassable "competitive transition charge." That is, this would be paid regardless of whether a customer chose direct access service or the traditional bundled service. It declared that all continuing utility services would be regulated under new performance-based regulatory systems based on either a revenue or price cap framework. It stated that the competitive market for generation under restructuring would replace the BRPU process mentioned earlier. In terms of environmental, energy efficiency, and fuel diversity goals, it noted that all environmental regulations remain intact and that the market would do the work of promoting renewables through "green" pricing plans as well as innovative demand-side management programs to attract customers. It left open the possibility of regulating demand-side management programs for those who remain customers of the traditional utility service. Finally, the CPUC conveyed a desire to work cooperatively with the state legislature on restructuring, although it was careful to point out that legislative action was not necessary for much of it. For example, with respect to allowing consumer choice through direct access, the Blue Book states: "…we will work with the Legislature to amend those sections of the Public Utilities Code necessary to exempt California-based generation service providers wishing to offer retail service from regulation as public utilities by this Commission. Though we recognize implementation of our proposal does not depend on amending the Code in this way, we believe doing so will greatly enhance entry into the competitive market for generation services." (CPUC, 1994, p. 38)

C. The CPUC Decides to Restructure (April 1994—December 1995)

Following the CPUC's intention to restructure announced in the April 20, 1994 Rulemaking Proceeding, extensive public hearings were held with testimony submitted by hundreds of individuals and organizations. Then on May 24, 1995, the CPUC issued majority and minority policy preference statements. Both fully supported restructuring, but with somewhat different ideas about how to achieve a healthy competitive environment. The main difference between the two positions had to do with the role of a centralized spot market. This difference had been highlighted in competing proposals offered during the proceedings by the utilities—one referred to as the "Direct Access

Model", in which primary reliance would be placed upon bilateral contracts to secure generation services, and the other as the "PoolCo Model", in which a centralized spot market would be the primary mechanism for securing generation services.

The majority preference was to create an entity, an independent system operator, that would perform two key functions: (1) operate a day-ahead auction market among generators and purchasers for the next day's electricity, and (2) arrange the necessary transmission access for all bids meeting the price determined by the pool. In the view of this majority, the introduction of any bilateral contracting could be deferred for two years while the pool was being established and customers getting familiar with the market.

The minority preference was for bilateral contracting to begin immediately, whether or not a wholesale spot market becomes established. Furthermore, while recognizing the need for independent system operation, the minority felt that the operator's role need not include the dispatch of generation except as necessary for system balance or stability. It also believed that multiple, competing operators of the transmission grid might be more desirable than a single operator.

It was clear to the CPUC that the types of restructuring envisioned raised many difficult issues of regulatory jurisdiction between the federal and state government. With a competitive generation market envisioned, there was little question that more interstate transactions would occur, and the Federal Energy Regulatory Commission (FERC) had jurisdiction over the setting of interstate transmission tariffs. No one knew at this point, for example, the extent to which either FERC or the CPUC would have jurisdiction over any entity running a centralized pool. But the CPUC called for an era of "Cooperative Federalism" in which both regulatory entities would agree on the stewardship and oversight of the restructured market.

The CPUC invited stakeholders to express their views on these positions. In September 1995, it received a Memorandum of Understanding (MOU) that conveyed the joint recommendations of some major participants in the proceedings (Southern California Edison, the California Manufacturers Association, the California Large Energy Consumers Association, and the Independent Energy Producers). This MOU suggested that two different entities fulfill the role that had been described previously for an independent system operator; it suggested that the spot market pool function be performed by a new entity called the Power Exchange. The basic rationale for this separation is so that the ISO would have no reason to favor "pool" electricity over any other electricity in pricing and scheduling transmission activities.

In October 1995, the CPUC received a joint submission from eleven organizations representing largely consumer and environmental interests.[2] It expressed concerns about a number of aspects of the restructuring, including protections for small and low-income customers, preservation of energy conservation programs, support for renewable energy, and research and development for energy efficiency.

[2] The submission is entitled "Framework for Restructuring in the Public Interest."

The December 1995 Policy Decision planned for all electricity to be provided through the spot market except for those retail customers who chose to obtain their electricity by direct access to generators and aggregators (wholesalers) through bilateral contracts. In other words, all those who chose to purchase their electricity from a utility would have the electricity obtained for them on the spot market.[3] While this decision did away with the two-year ban on bilateral contracts proposed in the May 1995 majority preference, it clearly emphasized the importance of the centralized spot market in its design.

The Policy Decision certainly reflected awareness at some level of the risk of spot market price instability to consumers. Customers could obtain long-run price stability by entering into financial hedging contracts with third parties, offering insurance against fluctuations in the spot price in return for some agreed-upon premium. This was seen as a major feature of customer choice, and apparently valued at least as highly as direct access bilateral (physical) contracts. The Decision mentioned that some think "such contracts represent but a variant upon the purely financial transaction…"(CPUC, 1995, Sections I.B.2. and I.B.3.)

Departing from its earlier majority position, the CPUC followed the September 1995 MOU and decided that two distinct entities would perform the spot market and transmission functions. The centralized spot market would be run by the "Power Exchange," which would have no financial interest in any source of generation or any ownership ties to the second new institution, the Independent System Operator. The Power Exchange would run a transparent auction for generation with hourly or half-hourly price signals. This would not only facilitate open competition among generators, but its competitive prices would benefit customers who stay with the utilities and provide crucial information for customers deciding whether or not to take advantage of the direct access opportunities or hedging contracts.

The Independent System Operator (ISO) would have the responsibility of coordinating the daily scheduling and dispatch activities of all market participants, in order to meet objectives of open, nondiscriminatory access, reliability, and achieving the lowest total cost for transmission. This includes applying a transmission pricing structure to be efficient and compatible with a competitive market. This means determining marginal cost prices, differentiated by location and time, for all uses of the transmission system. The ISO would take no position in the market nor have any economic interest in any load or generation. Its coordination function would be limited to the short-term, including day-ahead scheduling and hourly redispatch to make sure the system is in balance. The ISO would be indifferent as to whether any load comes from the PX or from a bilateral transaction. In addition, the ISO would administer a system of tradeable transmission congestion contracts.

The Policy Decision also evidenced substantial concern about the potential for abuse of market power in the new market, particularly in transmission and in the centralized spot market. In addition to its creation of two independent entities to manage these functions, it also required SCE and PG&E to file plans within 90 days for the voluntary divestiture

[3] As discussed below, this did *not* mean that a utility had to pay the spot price for all of it supplies.

of at least 50 percent of their fossil-fueled generating assets. The CPUC provided a financial incentive in the form of modestly higher stranded asset allowances with each 10% of fossil capacity divested, up to 50%, to encourage this divestiture.

A major issue in the restructuring discussions concerned the recovery of stranded costs. Essentially, all former utility investments were undertaken under the regulatory compact, in which those expenses found just and reasonable were allowed to be recovered through rates. Current net book values of utility assets are the allowable costs that have not yet been recovered. In a competitive market setting, however, the current market value of those assets may be above or below the net book values. When the market value is below, it means that competitive pricing for the services of the asset will not raise enough revenue to recover the net book value of the asset. The difference between the market value and the net book value is called a stranded cost, and the CPUC decided to honor the regulatory compact by allowing full recovery of the net stranded costs for the assets affected—primarily the generation assets as well as the contractual QF obligations.[4] These costs would be recovered by a nonbypassable competition transition charge (CTC). In the Policy Decision, the CPUC said that these charges would be set so that all stranded costs are recovered by 2005. This would be done in a manner that capped overall rates for consumers at the levels established on January 1, 1996.

Recall that the Blue Book had identified January 1, 1996 as the date at which the restructured market would begin with direct access for the largest customers. The CPUC had underestimated the time it would take to uncover and resolve all necessary issues, and recognized that much organizational design work remained to be done before the restructured market it envisioned could begin to operate. Thus its Policy Decision called for restructured operations to begin two years later—on January 1, 1998.

IV. The Legislative Period

At this point, attention turned to the state legislature. It might be noted that the Governor of California, Pete Wilson, was a Republican who fully supported the efforts to restructure the electric industry. The major interest groups—the utilities, large customers, and some important environmental and consumer organizations—all were known to support restructuring. The chair of the Senate Energy, Utilities and Communication Committee, Democrat Steve Peace, also favored this large-scale reform. It was the task of Peace's Committee to draft this legislation, and Peace did so in an unusual way. Rather than encouraging the usual behind-the-scenes negotiations of competing bills put forth by different interest groups, he held marathon public sessions in which all stakeholders had to work on a single bill together, often into the wee hours of the morning (Asmus, 1997).

Perhaps it is not surprising, under these somewhat unusual circumstances, that on August 31, 1996, the state legislature passed with complete unanimity (not a single vote against) the restructuring bill known as AB 1890, and the Governor signed it shortly thereafter. The bill left almost completely intact the design of the CPUC as specified in its Policy

[4] This is calculated so that any assets with market value above net book value reduce the amount of net stranded costs.

Decision. There were, however, several important provisions that either modified or redirected the CPUC in a few areas.

Primary among these were to go beyond the CPUC's call for a retail rate freeze to mandate a 10% rate cut during the four-year transition period that allowed for stranded asset cost recovery. This action was widely believed to be the result of political and not analytic reasoning: in order to motivate the legislature to undertake restructuring action, the legislators demanded some immediate benefit for their consumer-voters. The long-run benefits that motivated analysts and the CPUC to favor restructuring apparently were not sufficient for political action. This rate cut is discussed further below.

Additionally, there were numerous "public purpose" programs, most of which had been legislatively mandated, that required modification in a restructured environment. These programs included provisions for low-income consumers, energy efficiency, resource diversity concerns and other factors. It is not surprising that the legislature, as originator of these programs, would want to put its stamp on them for the restructured environment. A good example is resource diversity. The Blue Book proposed relying primarily on "green power marketing" as the way to promote renewables. Many environmental groups were not satisfied with this, and argued successfully during the CPUC hearings for stronger action. Thus the CPUC in its Policy Decision additionally supported a renewable portfolio standard approach that would require each year certain percentages of energy to be supplied from renewable sources. The legislature, however, rejected this approach in favor of a surcharge-funded program to partially support existing and new renewable energy projects during the four-year transition period beginning January 1998.[5]

V. The Implementation Period

A. The New System (September 1996-April 1998)

Once Assembly Bill 1890 had been passed, the structures that it mandated could be created.

1. *The California Power Exchange (PX)*

The California Power Exchange (PX) was required to operate an hour-by-hour spot market, in which generators could sell and retailers could buy power. To ensure that the market was liquid, the investor-owned utilities were required to meet the demands of their native loads – those customers who had not decided to buy power from an alternative service provider – in the PX. They also had to sell power from the stations that they owned or controlled (through QF contracts) through the PX. This restriction was to be abolished in 2002, giving the PX a head start in the market, but not guaranteeing a monopoly for life. The PX had a complicated governance structure headed by a large stakeholder board with representatives of the electricity industry, consumer groups, and public interest appointees.

[5] For further information, see Wiser, Pickle, and Goldman (1998).

The PX's main market was to be a day-ahead hourly spot market. That is, the market ran on Monday to set 24 prices for Tuesday, and so on. By 7 a.m. each day, generators and retailers submitted a separate schedule of up to 15 price-quantity pairs for each hour of the following day. These schedules were assembled into demand and supply curves, and the market-clearing price and quantity were given by their intersection. In the hydro-dominated Norwegian market where this model was developed, it is quite straightforward for generators to bid their plant for each hour independently, and there was little price variation between hours. Fossil generators, however, need to plan their operation over a number of hours taken together, and prices can vary significantly over the course of a day. To allow generators to adjust their bids in the light of the emerging prices in adjoining periods, the PX planned to hold a multi-round auction, and drew up an elaborate series of "activity rules" designed to give participants incentives to reach the final equilibrium quickly. In practice, it did not prove possible to implement a multi-round format for the first version of the PX's auction, and the single round did not appear to be a significant impediment to market efficiency. The problem of allowing generators to adjust their positions once they could see the pattern of prices over the day as a whole was dealt with by running additional auctions on the day itself. At first, there was a separate auction for each hour, but the volumes were often small, and prices volatile. From January 1999, the hour-ahead market was replaced by a "day-of market". This had three separate auctions, at 6 a.m., noon and 4 p.m., covering trades between 10:01 and 16:00, 16:01 and 24:00, and 00:01 and 10:00 respectively.

2. *The California Independent System Operator (CAISO)*

The PX effectively ran a commodity market for "raw" electricity, buying and selling MWh of power. Delivered electricity is a more complicated commodity, because of the characteristics of an electrical network. Generation and demand must be continually balanced, and because each is unpredictable, some generation must be held in reserve, able to increase its output on a time scale ranging from milliseconds (usually responding automatically, and known as "regulation") to hours. Power will chose its own routes through the grid from generator to consumer, and the flows will change instantly if a line fails. If too much power attempts to flow down a line, the circuit may be damaged. A large area can be blacked out in seconds by a vicious circle of overloaded lines which fail, or are saved by circuit-breakers which nevertheless take them out of action, leading to a reallocation of power flows which overloads more lines. To prevent this, the load on every line must be kept within operational limits that allow sufficient spare capacity to absorb extra flows in response to faults elsewhere on the system. A generator located in the wrong place will not be able to meet an increase in demand, because to do so would push the flow on some line over its safe limit. Note that the overloaded line may not even be close to the direct route between generator and demand, because electricity flows through every link on a meshed network.

Dealing with these problems was the responsibility of the California Independent System Operator (CAISO), the second corporation established by AB1890. We can identify three tasks – congestion management, providing ancillary services, and real-time balancing. Once the PX had issued its market-clearing prices and quantities, its participants provided initial preferred schedules, identifying the power stations that would generate in each hour, and the places where load would be taken. The participants also sent in location-specific adjustment bids, stating the prices at which they would be willing to sell more power (increasing generation or decreasing demand) or buy power back from the PX (decreasing generation or increasing demand). The PX, and all the other Scheduling Coordinators (SCs),[6] passed this information on to the CAISO, which then checked to see whether the proposed schedules were mutually feasible. If they were not, the CAISO would use the adjustment bids submitted to find the least-cost method of resolving the congestion.

In California, the lines between the north and the south of the State, known as Path 15, are frequently congested, and a pricing zone was established each side of the constraint to reflect this. If the proposed schedules involved, say, too much power flowing from the north to the south of the State, some northern generators would have to reduce their output, and some southern generators to increase theirs, unless there were consumers willing to adjust their plans. The CAISO would give SCs one chance to revise their proposed schedules to resolve the congestion voluntarily (although the PX did not make any revisions), and would then call on the adjustment bids. The cheapest available southern generators would be required to produce more power, and the most expensive running northern generators to produce less. The difference in adjustment bids of the marginal generators in each zone effectively defined the value of transmission between the two zones. SCs had to pay this charge for every MW they sent across the constraint, while the PX would abandon its single market-clearing price and use the transmission charge to set a different price in each of the two zones. In this example, the price would be lower in the north and higher in the south.

The CAISO also had to deal with intra-zonal congestion, where a local constraint on the system prevented a generator from running in the way it planned. The solution was to buy from or sell to the generator (or load) affected, and pass on the cost to all the SCs in the zone. In some cases, the CAISO (and the generator) could predict that a particular station would frequently have to operate because of a local weakness in the grid, and a lack of alternative stations in the area. Such stations could have raised their prices to unacceptable levels in a spot market, and so Reliability Must Run (RMR) contracts were devised, allowing the CAISO to negotiate with the stations in advance. In return for an availability payment intended to cover the station's fixed costs, the standard RMR contract allowed the CAISO to buy energy at a price close to the station's variable costs. In the initial contracts, the availability payment was made each time the station was called upon, and was set at a level that would recover the station's fixed costs if the expected number of calls were made.

The CAISO was also responsible for ancillary services, and in particular for providing reserve. Four separate markets were created, for Regulation (immediate changes in output to keep demand and generation in balance), Spinning Reserve and Non-Spinning Reserve (both able to provide additional energy within ten minutes) and Replacement

[6] Any bilateral transactions that did not pass through the PX had to be arranged by a Scheduling Coordinator.

Reserve. (This last category was for stations able to come on line in under one hour, generally to allow stations that had been providing one of the other types of reserve, and had been called, to return to that role). The CAISO received bids for all four auctions at the same time, and determined the market-clearing prices and quantities sequentially, starting with the market for Regulation. Capacity that was accepted in the Regulation market was removed from the Spinning Reserve market before its prices were calculated, and so on. The market-clearing price was for making capacity available (and hence in $/MW) – if the stations were called on to provide energy, this was paid for at the price determined in the CAISO's real-time market. The stations accepted in the ancillary services markets had each submitted energy charges (in $/MWh), while other generators could provide supplemental bids for increasing or decreasing their output. The CAISO ranked these bids, and would keep demand in line with generation by calling on the cheapest bids that were technically capable of doing so. The most expensive bid (if extra energy was required) or cheapest offer (if there was a surplus of power) set the market-clearing price in each ten-minute period, and this was paid for all the changes in generation instructed by the CAISO. The CAISO could not monitor uninstructed deviations from schedule at this level of detail, and so imbalances between a generator's (or retailer's) contractual position and its actual generation (or demand) were settled on an hourly basis. The CAISO's hourly real-time price is the average of the six ten-minute prices calculated within each hour. It was capped at a level of $250/MWh, which effectively capped the PX price at the same level, since no buyer would bid to pay more than $250/MWh in the PX when they could buy as much power as they needed in the real-time market at $250/MWh.[7]

3. *The Retail Market*

Most electricity consumers would not notice these markets, of course. For large consumers the utilities, retail rates were frozen. For small consumers the biggest initial impact of AB 1890 was to be the 10% rate reduction mandated by the bill, in order to pass on some immediate benefits to consumers. The reduction was made possible by the State, which guaranteed bonds issued by the utilities to finance the reduction. These "rate-reduction bonds" were used to buy down the utilities' plant. These transactions did not change the total value of the utilities' rate base but they did change the rate of return due on the rate base. That is, the rate base, which was initially all plant with an allowed rate of return of about 13%, became a mix of plant and government guaranteed bonds. The bonds had a rate of return of about 6%. This reduction in rate of return was not sufficient to support all of the 10% rate reduction, so the legislation provided for a non-bypassable charge that was to be collected until the bonds were fully amortised. In effect, consumers in the period following April 2002 were to partially subsidise the rate reduction.

[7] The price cap was raised to $750/MWh on October 1, 1999, reduced to $500/MWh on July 1, 2000, and back to $250/MWh on August 7, 2000. From December 7, 2000, the CAISO started to accept some bids above the level of the cap and pay these generators (only) their own bids, provided that those bids could be justified by high costs.

The resulting retail rates were expected to be significantly higher than the combined cost of wholesale electricity (measured by the price in the PX, and for other purchases by the utilities) and the utilities' rates for transmission and distribution. The difference was to be known as the Competitive Transition Charge (CTC), and was to be used to pay off the utilities' stranded costs. The CTC would be eliminated from the utility's rates once its stranded costs had been paid off, or on April 1, 2002, whichever came first. This meant that once the CTC had expired, the rate for "default service" from the incumbent utility would be equal to its transmission and distribution charges, plus its actual payments in the wholesale markets, passed on through monthly bills. If the utility continued to buy all its power in the PX, its consumers' monthly bills would be based on the PX's average spot price.

As soon as the market opened, all consumers were eligible to switch to alternative retail providers. There was considerable optimism about the prospects for retail competition. The CPUC launched an $80 million public information campaign to inform consumers that they would be able to choose a new supplier when the market opened. However, this optimism proved to be misguided—only a small fraction of consumers chose new suppliers. Several factors created difficulties for potential new entrants. A customer who elected not to buy power from the incumbent would receive a "shopping credit", but this was set equal to the utility's cost of purchasing power, to ensure that consumers could not escape the CTC by changing service provider. (The customer paid the incumbent its retail rate minus the shopping credit, or in other words, its CTC and its transmission and distribution charge). The result was that competitive service providers could only undercut the incumbent if they were willing to sell power retail for less than the wholesale price, which was never likely to be a winning strategy, or if the incumbent was somehow paying more than the going wholesale price for its power. Competitive service providers would be able to sell power at fixed rates, providing a hedge against high wholesale prices in the spot market. This would potentially be one of their main competitive advantages. Until the CTC had expired, however, this strategy was not available to competitive service providers since the frozen retail rate already provided a hedge. An alternative strategy would have been to sell power at the real-time price. Consumers who had loads that were less peaked than the average load would benefit because more of their supply could be purchased at low off-peak prices. However this strategy had to overcome the relatively higher cost of real-time meters. In the end, few consumers were to switch, and many of those would buy "green power" at premium rates. Where retail competition has been a success (in terms of the numbers of consumers switching), regulators have allowed entrants to undercut incumbents, setting either a "shopping credit" which exceeded the expected cost of wholesale energy, or an equivalent pattern of regulated prices for transmission and distribution and for retail energy.

4. *Generation Ownership*

In the very early days of the new market the IOUs owned or had under contract almost all of the generation. However, the IOUs were strongly encouraged to divest half of their thermal units, but in fact went further than this. Southern California Edison had divested most of its thermal units within a month and a half of the market opening, while Pacific Gas and Electric divested some units in July 1998 and most of the rest in April 1999. San Diego divested its thermal units in April and May 1999. Five companies – AES, Duke, Dynegy, Reliant, and Southern (later Mirant) – each purchased roughly a fifth of the divested plant

Table 1 shows the mix of capacity in California at the end of 1999. One-tenth was nuclear plant, owned by the IOUs and running base load. The QFs, owned by independent companies but selling to the IOUs under long-term contracts, made up another fifth of the capacity. One quarter of the capacity was hydro-electric, partly owned by the federal and state governments and municipal utilities, as well as by the IOUs and other companies. Two-fifths were conventional thermal plant, almost all fuelled by natural gas. Most of the plants in this category had been divested, but Southern California Edison had kept some coal capacity, physically located in Nevada, but treated as Californian. For most levels of demand, one of these gas-fired stations would be at the margin, and hence setting the market price. The final category in the table, about one tenth of the total capacity in the state, represents non-hydro stations, owned by relatively small companies, that did not have QF contracts with the utilities.

Table 1:Generating Capacity in California, end-1999

GW	Thermal	Hydro	Nuclear	QF (all types)	Other	Totals
PG&E	0.6	3.7	2.3	5.0		11.6
SCE	1.7 a	1.2	2.4 a	4.3		9.5
SDG&E			0.5	0.2		0.7
AES	4.7					4.7
Duke	2.9					2.9
Dynegy	2.9					2.9
Reliant	4.0					4.0
Mirant	3.2					3.2
Others	1.1 b	9.1			6.0 c	16.2
Totals	21.1	14.0	5.1	9.5	6.0	55.7

Source: California Energy Commission
Notes:
a Figures for SCE include coal and nuclear capacity located outside the State border
b Plant divested by the IOUs to companies with less than 1 GW of capacity in California (and, by implication, little market power)
c This is a residual for plant of all types apart from hydro, and includes 1.4 GW of geo-thermal plant divested by PG&E

Table 2 shows the contribution made by the different fuel types during the late 1990s. Nuclear power contributed about 15% of California's electricity requirements between 1996 and 1999, while coal and "other" fuels (mostly renewable sources) contributed about 20% - coal's share rose while the share of renewable generation declined slightly over the period. Natural gas, and a small amount of oil, contributed just under 30% of the total, while in-state hydro generation came to slightly under 20%. California imported approximately 50TWh in each year between 1996 and 1999. At the start of the period, this was about one fifth of the state's requirements, although the share fell slightly as total production grew. The dramatic reduction in imports during the two crisis years, 2000 and 2001, and its impact on the California markets, is an important part of our story.

Table 2 – Electricity Production in and for California, 1996-2001

	1996	1997	1998	1999	2000	2001
TWh						
imports	49.7	52.7	47.6	49.5	26.8	16.8
gas & oil	67.4	74.5	82.2	84.8	107.3	114.9
hydro	47.9	41.4	48.8	41.6	42.1	28.0
coal	25.5	27.1	34.5	36.3	36.8	40.6
nuclear	39.8	37.3	41.7	40.4	43.5	41.3
other	23.4	22.1	21.7	23.2	24.0	23.5
Total	253.6	255.1	276.4	275.8	280.5	265.1

Source: California Energy Commission

Note: The CEC changed its definition of imports. in 2001, but these figures have been adjusted, using the notes to the CEC table, to keep them comparable with earlier years

Unlike most other markets where divestiture (or privatisation) occurred, the California divestiture did not include vesting contracts (*i.e.*, contracts agreed before the sale, covering most of the output of the plant for some period of time after the sale). Vesting contracts were discouraged by the CPUC, which was not willing to guarantee the IOUs that the costs of energy purchased under vesting contracts would be fully recovered. The reluctance of the CPUC to guarantee recovery of costs from vesting contracts may have been due in part to the early optimism about the growth of the retail market. If retail competitors took a large volume of sales away from the IOUs, the vesting contracts could have become stranded assets.

The CTC had the potential to act as a hedge for the utilities. Assume that wholesale prices were sufficiently low for the utility's stranded costs to be fully paid off before the deadline for the CTC to expire. In that case, the utility's revenues over any period from the start of restructuring which ended after the stranded costs had been paid off would equal the utility's stranded costs, plus its transmission and distribution rates, plus its purchase costs. Those revenues would exactly equal the utility's costs.

The key phrase in the previous paragraph was the assumption about the level of wholesale prices. Utility revenues over the first four years after deregulation had an upper limit, while their costs based on wholesale prices were variable. If wholesale prices were too high, then the utilities would not be able to recover their stranded costs before the April 2002 deadline. There seems to have been very little recognition of the risk of financial distress that even higher wholesale prices could cause. In 1998, the California Energy Commission had forecast an average market-clearing price of \$26.5/MWh in 2000, easily low enough to allow the full recovery of stranded costs before the deadline.

In February 2000, the Commission had observed rising prices for natural gas, and raised their forecast, but only to $28.5/MWh, still well within the safe region.

B. The system in operation: April 1998 – March 2000

The new markets began operation for April 1, 1998. This was three months behind the original start date, but it had not proved possible to create the necessary computer systems in time. As it was, the markets started before all the final systems were in place, and some temporary patches were needed to keep things going.

The PX ran quite smoothly, with low prices (see Table 3), but there were problems in the CAISO's ancillary services markets. FERC had not given authority for market-based rates in these markets, and so all the bids were based on cost estimates. This made some participants unwilling to offer their plant in the CAISO's markets, as the (market-based) prices in the PX were higher. Many of the stations with RMR contracts knew that the CAISO would have to call these contracts if the stations were not offered voluntarily. The RMR contracts promised much higher payments than the cost-based CAISO markets, and so the CAISO was frequently short of offers, particularly for Regulation, until an emergency price adder, known as REPA, was introduced in mid-May.

From June 30th onwards, FERC allowed some generators, those owning plant sold by the incumbent utilities, to bid without restriction, and hence to set market-based rates in the CAISO's markets. This caused a sharp increase in prices, in part because of the CAISO's buying rules. The CAISO was required to buy a fixed amount of each type of reserve, whatever the price, and could not even substitute reserve of a *higher* quality (faster response) available at a lower price (Wolak, Nordhaus, and Shapiro, 1998). This inflexible demand offered superb opportunities for the exploitation of market power, and on July 13 1998 the price for Replacement reserve reached $9,999/MW. Apparently, the bidders (mistakenly) believed that the CAISO software could only cope with 4-digit bids. The CAISO quickly imposed a bid cap of $500/MW, later reduced to $250/MW, and pondered changes to the market rules. A "rational buyer" protocol allowed it to substitute higher- for lower-quality products if these were available at lower prices. FERC allowed the remaining generators to receive market-based rates on October 28, eliminating some of the perverse incentives to avoid the CAISO markets, and the emergency price adder (REPA) was removed on November 27. Over the (fiscal) year as a whole, the CAISO's costs came to 19% of the total cost of wholesale power (CAISO, 1999, figure 1-1).[8]

[8] To put this figure in context, it might be worth noting that in England and Wales, Uplift, which contained charges equivalent to roughly 70% of the ISO's costs in that year, averaged 7% of the total cost of wholesale power between 1990 and 2001.

Table 3 - California Wholesale Electricity Prices – Monthly Means ($/MWh)

	1998/9	1999/00	2000/1	2001
Apr	23.3	24.7	27.4	265.9
May	12.5	24.7	50.4	239.5
Jun	13.3	25.8	132.4	159.8
Jul	35.6	31.5	115.3	137.8
Aug	43.4	34.7	175.2	120.1
Sep	37.0	35.2	119.6	126.8
Oct	27.3	49.0	103.2	69.4
Nov	26.5	38.3	179.4	74.8
Dec	30.0	30.2	385.6	69.6
Jan	21.6	31.8	272.0	
Feb	19.6	18.8	304.4	
Mar	24.0	29.3	249.0	
Mean	26.2	31.2	176.2	

Sources: PX prices as reported in Joskow (2001) for 1998 through 2000; CAISO and CDWR data as reported by the CPUC (http://www.cpuc.ca.gov/static/industry/electric/electric+markets /historical+information/average+energy+costs+2000+thru+2001.xls) for 2001
Note: The prices for 1998 – 2000 are not strictly comparable to the prices for 2001 since the PX price is for day-ahead transactions while the CDWR data include prices for longer-term contracts.

The PX was the dominant market for electricity. The IOUs were formally required to meet all of their needs through it (although in practice they also bought in the CAISO's real-time market), and rival markets were caught in a vicious circle of inadequate liquidity. In the first year, prices were generally in line with forecasts, although there were signs that some generators had market power at times of high demand (Borenstein, Bushnell, and Wolak, 2002). The IOUs may have had an incentive to speed up the collection of their stranded costs by keeping prices down when bidding the stations that they still owned. After divestiture, the stations' new owners were net sellers, and therefore were likely to want high prices.

The ability of any seller to obtain higher prices depends upon the market structure. Overall, the industry does not look particularly concentrated, but the particular features of electricity, and especially its almost completely inelastic demand, can allow generators to raise prices sharply at peak times. This happened in the summer of 1998, and again in 1999. Average prices in fiscal 1999 were 16% higher than those in 1998, and slightly above the California Energy Commission's predictions, but still low enough to allow San Diego Gas and Electric to pay off all of its stranded costs. Starting in the beginning of the year 2000, San Diego consumers who stayed with their local utility saw the PX price passed straight through to their monthly bills. The other IOUs appeared to be on course to follow suit.[9]

In the summer of 1999 the PX opened a short-term (one-year or less) forwards market, designed to allow companies to purchase power ahead of the opening of the spot market, and reduce their exposure to the spot price. Buying strategies differed among IOUs and only SCE made much use of this market. The continued low prices in the PX, the CTC mechanism, and the promised future pass-through of spot prices into retail rates appeared to give the utilities all the price insurance they would need.

The CTC mechanism did not actively discourage hedging, since the CTC was based on the utilities' overall purchase costs. Given California's unfortunate experience with long-term power purchase agreements at high prices for the QFs, however, the CPUC appeared reluctant to allow the utilities to buy much power on long-term contracts. The CPUC did allow the utilities to hedge up to 20% of their requirements without having to undergo a prudential review of the purchases (which might have disallowed any "excessive" costs after the event), and SCE took advantage of this opportunity. PG&E and SDGE continued to buy almost all of their power on the spot markets.

VI. The Market Collapses

Late in the spring of 2000 the California's new electricity market began to collapse. In May the average PX price was \$50/MWh, higher than any previous month. There were also numerous price spikes. Prices reached the CAISO's \$750/MWh price cap in either the real-time or ancillary service markets 23 times. In June the wholesale prices averaged \$132/MWh. Wholesale price caps were lowered to \$500/MWh in July and \$250/MWh in August but average wholesale prices remained high during the summer. Wholesale prices eased somewhat during the fall but then spiked dramatically in December (See Table 3). By the end of January, the collapse was complete. Blackouts occurred on eight days during the winter and spring even though demand was far below the summer peak (See Table 4). The Power Exchange suspended operations, and the CAISO, SCE and PG&E were all insolvent.

What caused this remarkable breakdown? The *post mortem* is not complete, but a number of factors have been identified as potential contributors to the market's collapse. These factors include a supply/demand imbalance combined with a retail price freeze that prevented supply and demand from equilibrating, exogenous increases in the prices of some key inputs, poor design of the electricity market, the exercise of market power by generation owners, and inept regulation. In what follows, we examine some of what is known about these factors.

[9] By September 2000, SCE and PG&E "…declared their generation-related stranded costs collected, and requested the end of the rate freeze…." See Joskow (2001) p. 377. However, as problems in the wholesale market were mounting, the CPUC rejected this request at the same time that the legislature was reregulating SDG&E retail rates under AB265.

Table 4. Rotating Blackouts in California 2000-2001

DATE	DAY	Peak Demand (MW)	Firm Power Curtailed (MW)	Number Hours Curtailed
06/14/00	Wednesday	44239	100	NA*
01/17/01	Wednesday	29727	500	3
01/18/01	Thursday	29537	1000	3
01/21/01	Sunday	27657	101	1
03/19/01	Monday	29476	1000	6
03/20/01	Tuesday	29691	500	6
05/07/01	Monday	33446	300	2
05/08/01	Tuesday	34455	400	2

*Not Available. This curtailment, localized to the South San Francisco Bay Area, was caused by transmission constraints

Source: CAISO System Status Log (http://www.caiso.com)

A. Supply and Demand

The supply/demand story is not simple because, first, the supply/demand situation in the summer of 2000 is very different from the winter of 2001 and, second, these stories are partly about supply and demand in California and partly about supply and demand in the entire western region of the US and Canada.

During the period 1990 to 2000, load growth in California averaged about 1.2%/year (Brown and Koomey, 2002). The growth of consumption in the CAISO's control area was a relatively strong 5.2 % between 1999 and 2000, but the peak demand in 2000 (43,509 MW) was actually slightly lower than in 1999 (45,574 MW). Growth during the '90s was stronger in other parts of the west, especially the southwestern states of Arizona, New Mexico and Nevada (Fisher and Duane, 2002).

After the addition of about 6,500 MW of QF capacity in the period 1987 to 1991, capacity additions in California came nearly to a halt during the rest of the decade. This slowdown also occurred in the rest of the western region. One reason that has been suggested for this slowdown is that strong additions during the 1980s had created over capacity. A second reason is that the CPUC's decision in 1994 to restructure the electricity industry created uncertainty among potential investors that caused them to postpone investments in new capacity. In any event, demand was beginning to catch up to the capacity to supply.

The gap between demand and the capacity to supply was further narrowed by the fact that the winters of 1999-2000 and 2000-2001 were both very dry in the Pacific Northwest with the result that the Northwest's exports of hydroelectricity were greatly reduced (See Table 2).

Borenstein, Bushnell, and Wolak (2002) suggest that tight supplies made it easier for in-state generators to exercise market power. However, it is hard to argue that rotating outages were caused by an absolute shortage of generating capacity. As can be seen from Table 4, only one of the system's outages occurred when demand was above 40,000 MW and that outage was caused by transmission constraints, not a shortage of generating capacity available to the CAISO. Five outages occurred when demand was less than 30,000 MW and the remaining two outages occurred when demand was less than 35,000 MW. The problem for these seven outages was that existing capacity was not available.

B. Prices of Inputs for Power Generation

Marginal generation is fueled by natural gas most of the time in California. In 1998 and 1999 natural gas prices were relatively stable averaging about $2.70/MMBtu. In January of 2000 prices, which were then about $2.00/MMBtu, began a steady rise. The price reached $4.00/MMBtu by June and $6.00 by September. The price fell back slightly until the beginning of November and then a spectacular rise began. In December the price averaged $19.00/MMBtu and is reported to have spiked above $50.00/MMBtu (Wilson, 2002).

Fuel is the dominant component of the marginal cost of generation plants powered by natural gas. When natural gas costs double, the marginal cost of natural gas generation nearly doubles as well. For a natural gas fired steam turbine generating station with a heat rate of 10,000 Btu/kWh (about average in California), $1.00/MMBtu increase in the natural gas price pushes up the marginal cost of electricity by $10.00/MWh. For a combustion turbine with a heat rate of 14,000 Btu/kWh (typical of a peaking plant in California) an increase of $1.00/MMBtu in the gas price increases the marginal cost of electricity by $14.00/MWh.

In the winter of 2000-2001, the high gas prices did more than raise the price of electricity, they also seriously disrupted the market. When the gas price spiked above $25/MMBtu the marginal cost for natural gas plants with a 10,000 Btu/kWh heat was above the $250/MWh price cap and these plants could not sell into the market without losing money.

Another input to electricity generation that had an unanticipated price increase was pollution permits in the South Coast Air Quality Management District (SCAQMD). SCAQMD, which covers Los Angeles Basin airshed, has a "cap-and-trade" system to control emissions of NOx from stationary sources. Under this system power plants are required to have permits to cover their emissions. These permits, which are tradable, are issued to stationary sources in quantities that decline as emissions are ratcheted down over time. Between April and September 2000 the price of these permits increased by almost a factor of 10. Causes of this price increase probably included the declining number of permits available and the increased use of gas-fired power plants owing to reduced imports of hydro electricity. According to Joskow (2001), "By September 2000, NOx permit prices increased marginal supply costs from a gas-fired steam unit in the

SCAQMD by $30 to $40/MWh and increased the marginal supply costs from a peaking turbine by $100 to $120/MWh."

C. Market Design

In assessing the role of market design in the collapse of the California market, one needs to consider the initial conditions when the market opened, the market structure, and the market rules.

To a large extent initial conditions were outside the control of the market designers. That is, the market designers could not much influence the initial endowment of electricity plant. However, it was possible to influence ownership of the plant and the initial contractual relationships among generation owners and utility distribution companies. As discussed earlier, the incumbent utilities were strongly encouraged to divest themselves of their fossil-fueled generators and the incumbent utilities were not allowed to enter into any vesting contracts to buy back the output from these generators. In retrospect, the absence of vesting contracts combined with the retail price freeze and the failure of retail competition to develop set the stage for the market's collapse.

The market structure was a compromise between advocates for a centralized pool and advocates for a system of bilateral trading. The PX, although separate from the CAISO, had most of the market volume because the utility distribution companies were required to buy and sell in the PX. The market design included a role for the CAISO, which was to operate a market for ancillary services and a balancing market. The purpose of the balancing market, usually called the real-time market, was to adjust for forecast errors in the day-ahead market.

When the market was designed, volume in the real-time market was expected to be small. However, in the summer of 2000 volume in the real-time market increased substantially. This change was due in part to problems with market rules that are analysed in detail by Wolak, Nordhaus, and Shapiro (2000). Among the problems were changes in the rules made in August 1999 that increased the opportunities for generators to receive payments both for providing energy and for providing reserves. This sometimes resulted in payment to generators that were above the CAISO's price cap. These high prices increased the financial pressure on the utility distribution companies and probably accelerated their descent into insolvency. The shift to the real-time market was also destabilizing for the system because more of the supply had to be arranged at the last minute.

One element that has been widely identified as a problem in the market rules is "over reliance on the spot market" resulting from a "prohibition" on forward contracting. Apparently the FERC believed, when it issued its December 15 order (see below) that the system was 100% reliant on the spot market. This was never the case since prices paid for utility-owned generation and for QFs were determined by regulatory side agreements. Also, as noted earlier, the PX had a forward market that opened in 1999. The utility distribution companies could purchase 20% of their requirements in the PX forward market with recovery of the cost guaranteed by the CPUC; this was about 50% of what came to be known as the "net short."[10] The utilities were not prohibited from making forward purchases in excess of 20%, but recovery was not guaranteed by the CPUC. In practice, when the market collapsed, the market positions of the utility distribution companies were that SDG&E did not have any forward contracts, PG&E had used only a small fraction of its potential guaranteed-recovery forwards and SCE had used a large fraction of its guarantees.

It has been argued that the PX forward contracts were too inflexible to meet the needs of the utility distribution companies (Wolak, Nordhaus, and Shapiro, 2000). In hindsight one certainly wishes that the utility distribution companies had had much larger forward positions but it is far from clear that rule changes to give them more flexibility in forward contracting would have led to that result.

The greatest weakness in the design of the market was probably the absence of any mechanism for demand to respond to the wholesale price. While this deficiency was especially acute in California (prices frozen for four years), it is a problem in all electricity markets. What appear to be needed are retail prices that reflect the wholesale price in real time, at least for large customers. Borenstein (2001) argues that real-time prices will lead to a more efficient allocation of resources and will restrain market power.

D. Market Power

Several studies have attempted to determine the role that market power played in the in the high prices that obtained during the summer of 2000. The studies focussed on calculating the "competitive benchmark price"—the price that would have obtained if the market were perfectly competitive and all suppliers bid marginal costs (Borenstein, Bushnell and Wolak, 2002; Joskow and Kahn, 2002.) These analyses demonstrate convincingly that actual prices were well above the competitive benchmark. According to Borenstein, Bushnell and Wolak (2002), "Efficient production costs more than tripled between [the summer of 1998 and the summer of 2000] and, with the marginal unit having higher costs, competitive rents for lower cost units quadrupled. Oligopoly rents, however, increased by an order of magnitude, from about $425 million to $4.44 billion between these summers. Thus while a substantial portion of the increased market cost of power was due to rising input costs and reduced imports, these factors also increased the dollar magnitude of the market power that was exercised by suppliers. [T]he underlying competitive structure of the market does not appear to have changed substantially between 1998 and 2000. Rather the higher demand and lower import levels in 2000 created more frequent opportunities for instate fossil-fuel producers to collect large margins on increased costs, leading to the 10-fold increase in oligopoly rents to suppliers." Table 5 gives total payments and Borenstein, Bushnell and Wolak's estimates of competitive payments for June through October in 1998, 1999, and 2000.

[10] The "net short" was the total demand less the amount available from utility-owned generation and QFs.

Table 5. Total Payments and Competitive Payments in California's Wholesale Electricity Market Summer and Early Fall (June through October)1998, 1999, and 2000.

	1998	*1999*	*2000*
Total Payments (a)	1672	2041	8977
Total Competitive Payments (b)	1247	1659	4529
Monopoly Rents (a – b)	425	382	4448

Source: Borenstein, Bushnell, and Wolak (2002), Table 3.

Much less information is available about generator behavior during the winter months of 2001. The collapse of the PX meant that a uniform market clearing price was not available to conduct the type of analysis that was performed by Borenstein, Bushnell and Wolak to estimate price/cost margins for the summer of 2000. Possibly, some measure of market power could be derived from analysis of the bilateral agreements between the generators and the CDWR, but this has not yet been attempted.

Clearly the situation was highly unusual. One must wonder how it was possible that there was a rotating outage on a Sunday in January when the demand was about 27,700MW, which was only about 60% of the summer system peak. One common explanation was that an unusually large amount of capacity was offline for maintenance (cite CAISO press releases). Unfortunately, outage data for the period between April 1, 1998 and November 1, 2000 are incomplete. As can be seen from Table 6, outage rates in the winter of 2002 were not very much lower than outage rates for the winter of 2001. A comparison of these data with outage data prior to April 1998 would show whether there has been a change in outage rates since the advent of restructuring, but this also has not been attempted.

Another factor that may have contributed to the winter shortages is QFs that sold their output to utility distribution companies may have gone offline because they were not being paid because the utility distribution companies were insolvent. Although this is widely rumored to have been a problem, data are not available to show the extent of the problem.

E. Regulation

As discussed in Moore (2002), responsibility for the regulation of the electricity industry in California was fragmented among several different agencies with unclear divisions of responsibility among them. It was clear however that wholesale prices lay within the jurisdiction of the FERC. The high prices of the summer of 2000 lead to appeals to the FERC to take action. The FERC's earlier decision to allow generators to charge market-based rates was based on a finding that the California market was "workably competitive." On November 1, 2000 the FERC issued a proposed order in which it found that prices in California had become "unjust and unreasonable" and that FERC intervention was therefore justified under the Federal Power Act. The proposed order included price mitigation measures. The November 1 order was finalized on December 15, 2000 with some modifications.

Table 6.Statewide Average Daily Forced and Scheduled Megawatts Off-Line 1999 - 2002

1999		2000		2001		2002	
Month	Average of Total Megawatts Off-Line	Month	Average of Total Megawatts Off-Line	Month	Average of Total Megawatts Off-Line	Month	Average of Total Megawatts Off-Line
Jan	3,068	Jan	2,423	Jan	9,940	Jan	11,166
Feb	5,096	Feb	3,243	Feb	10,895	Feb	12,702
Mar	5,740	Mar	3,389	Mar	13,737	Mar	12,753
Apr	5,739	Apr	3,329	Apr	14,911	Apr	11,385
May	3,032	May	4,012	May	13,431	May	
Jun	1,216	Jun	2,683	June	6,758	June	
Jul	963	Jul	2,233	July	5,044	July	
Aug	878	Aug	2,434	Aug	4,229	Aug	
Sep	1,195	Sep	3,621	Sep	5,278	Sep	
Oct	1,761	Oct	7,633	Oct	8,805	Oct	
Nov	2,988	Nov	10,343	Nov	12,199	Nov	
Dec	2,569	Dec	8,988	Dec	11,112	Dec	

Source: California Energy Commission Compiled From ISO Data

Filings of outages with the ISO have varied in consistency since June 1998, with incentives existing to both over- and under-report. The data, especially for periods prior to November 2000, may differ from outage values reported by other sources and in other documents, and should be considered indictative of general trends in unit outages, not as a precise measure of unavailable capacity.

The two principal price mitigation measures in the December 15 order were elimination of the "must-sell" (in the PX) requirement for generation owned by the utility distribution companies and the imposition of a "soft cap" on market prices.

The must-sell requirement was replaced by a prohibition against sales in the PX. Apparently, elimination of the must-sell requirement was based on the FERC's mistaken belief that, if the utility distribution companies did not have to pay high PX prices for their own generation, then the power procurement costs for these companies would be reduced. [Actually, the utility distribution companies settled with the PX based on the net of all of their transactions with PX. The high prices paid for their own generation were offset by the high payments they received for their own generation.]

The soft cap, which was set at $150/MWh, was intended to allow generators to recover their costs if these costs could be verified and exceeded the cap. Generators were permitted to bid above the cap and to receive the bid price when their costs were above the cap. Enforcement was to be based on an after-the-fact review of sales made above the price cap. The soft cap was intended to produce a hybrid auction—for bids under $150/MWh there would be a uniform price set by the highest bid under $150/MWh while for bids over $150/MWh the rule was pay-as-bid.

Neither the prohibition on utility distribution company sales in the PX nor the soft cap did much to reduce prices. The prohibition on sales was based on a false premise and did not reduce utility distribution company costs. The soft cap was largely ignored with suppliers continuing to offer prices that were well above the cap. Whether this was because costs were in fact well above the cap or for some other reason remains a subject of both debate and litigation. Other possible reasons for ignoring the soft cap include that the order was misunderstood, that suppliers believed that enforcement would be weak, or that generators were first selling to marketing companies who would then sell in the wholesale market and thus have "justification" for their high costs,

However, the impact of FERC's order on the PX was severe. Since most of the non-utility generators had already shifted their sales to the real-time market, the prohibition on utility sales in the PX reduced the PX's volume to near zero. Furthermore, the PX could not implement the soft cap because the requirements for a hybrid auction were incompatible with the CAISO's congestion management procedures. With little volume and operating procedures that violated the FERC order, the PX was forced to suspend operations on January 31, 2001. With no revenues, the PX could not be sustained as a going concern and declared bankruptcy in March 2001.

F. The State Takes Over

Meanwhile, PG&E and SCE, caught between continuing high wholesale prices and the frozen retail rate, defaulted on payments due to the PX in early January. These defaults caused the PX to default on payments to the CAISO for ancillary services, with the result that the CAISO also became insolvent. With the PX unable to operate within the rules set by the FERC order and with PG&E, SCE, and the CAISO all insolvent, the market simply collapsed.

Since the principal buyers of electricity were no longer creditworthy, the state of necessity became the buyer. Emergency legislation authorized the California Department of Water Resources (CDWR) to begin procurement of electricity on behalf of the state's consumers. The CDWR's authority included both spot purchases and long-term contracts. Price formation, which had previously been fairly transparent, now became opaque, as no details of the bilateral agreements between the CDWR and suppliers were publicly available until many months after the agreements made.

Although demand was now much lower than it had been during the summer, a number of factors contributed to a very tight supply. Rainfall in the Pacific Northwest was very low so production of hydroelectricity was down and exports from the Northwest to California were much reduced. High planned, unplanned and forced outage rates reduced the availability of non-utility fossil generation. Qualifying facilities, which were not being paid by the insolvent utility distribution companies, began to go off line. The result was the very high prices in the first five months of 2001 (see Table 3) and the periods of rotating blackouts shown in Table 4. As late as May 31 there was a Stage Two emergency (reserves between 5% and 1.5%).

VII. The Crisis Ends

Unexpectedly, in the first week in June prices fell sharply and the situation began to stabilize. There were two more Stage Two emergencies on two hot days in early July and then no more emergencies for the remainder of 2001. Several factors contributed to the end of the crisis.

Goldman, Barbose, and Eto (2002) report that during summer 2001, Californians reduced electricity usage by 6% and average monthly peak demand by 8%, compared to summer 2000. These authors examine a variety of factors that might have caused this reduction in demand. They conclude that neither the weather nor the economy were important causes and that the reduction in demand was the result of a variety of purposive efforts to limit consumption. They suggest that without the reduction in demand, *ceteris paribus*, there would have been between 50 and 160 hours of Stage 3 emergencies during the summer of 2001.

In May and June of 2001 California gas prices fell from around $12/MMBtu to around $5/MMBtu. By September, prices had dropped to historical average levels of $2-$3/MMBtu. Wilson (2002) suggests that this price drop was the result of a number of factors including weaker demand, higher levels of storage, reforms of pipeline capacity allocation rules, and reduced concentration in the market for pipeline capacity. Whatever the cause, the consequence of the gas price drop was a very substantial drop in operating costs for gas-fired generators.

On April 26, 2001 FERC issued another order dealing with the California crisis (FERC Order, 2001a). This order took effect on May 29, 2001 and was revised and strengthened on June 19, 2001 (FERC Order, 2001b). The new orders substantially revised the FERC's approach to mitigating unjust and unreasonable prices. The orders created caps on the price that each generator could ask for its output. These bid caps were based on heat rates and fuel costs. In the second order the caps were extended from California to the entire western region. Generators were required to offer all available capacity and the market price was set at the highest accepted bid. The orders included measures to foreclose price-inflating strategies such as "megawatt laundering"[11] and were in many respects more difficult to evade than the December 15, 2000 order. In effect, generators were compelled to behave as price takers in a uniform price auction.

[11] In the megawatt laundering strategy, generators in California whose price would have been capped if their output had been sold to California buyers sold instead to out-of-state buyers. The out-of-state buyers then sold the power back to California at above-cap prices.

In the spring of 2001 the state, acting through the CDWR, began entering into contracts with generators. By the beginning of June generators were delivering significant quantities to the grid under these contracts. In addition to their contribution to supply, these contracts had incentive effects that may have been important. A generation owner who committed part of his capacity to a contract had a reduced incentive to withhold his remaining capacity to raise the price. An owner who withheld capacity would have to forego profits that might have been earned by the capacity that was withheld but he would not benefit from a higher price for his contracted capacity since the contract price was already fixed. Another incentive effect was that before the contracts, high natural gas prices lifted the market-clearing price of electricity—to the benefit of the generation owners. After the contracts, generation owners whose contracts were not indexed to the gas price (about 60 % of the capacity under contract) had a strong incentive to hold gas prices down.

The system also benefited from the availability of additional supplies. In early June San Onofre Nuclear Generating Station (SONGS) Unit 3 came back on line. This 1100 MW unit had been offline since January because of an electrical fire in its control room that occurred when the plant was trying to restart after a scheduled outage for refueling. Several new thermal plants with a total capacity of more than 1400 MW were also brought online by the end of the summer.

VIII. What Is Next for California?

As of this writing, a replacement for the failed market and the stop gap measures that are now in place in California has not yet been devised. Prices remain stable, but the state is continuing to be the primary buyer of electricity, PG&E is still entangled in bankruptcy proceedings, state agencies and the FERC are in conflict, and there is no consensus about how to repair the market.

To make matters worse, there is no consensus about what exactly went wrong and why. This is partly because of the complexity of the situation and partly because much of the discussion about what went wrong has been very contentious—involving attempts to assign or avoid blame for California's problems. We have no expectation that our analysis will lay the current controversies to rest. But we have tried to contribute to the careful study that is necessary to develop an understanding of what happened. Without such an understanding, mistakes of the past are likely to be repeated and the problems of the California electricity market will remain intractable.

Acknowledgments

The authors are grateful for the research assistance of Amol Phadke and helpful comments from Severin Borenstein.

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