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**California's Electricity Crisis:
A Market Apart?**

James Bushnell

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2510 Channing Way, Suite 5
Berkeley, California 94720-5180
www.ucei.org

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Abstract

The factors most often cited as the causes of the California crisis are the scarcity of generation capacity, a flawed market design, and the venality of electricity producers. However, many of these attributes were present in other electricity markets, none of which have suffered through anything like the California crisis. The only factor not seen in other markets in the world is the lack of contracts or other forms of long-term supply arrangements. Policy efforts are therefore best directed at developing a regulatory and retail environment where contracts are freely entered into at prices reflective of underlying market conditions.

Keywords: electricity deregulation, energy markets, competition policy

Introduction

California has earned a reputation as an incubator of bad public policy ideas. Its experience with electricity industry restructuring has contributed substantially to this reputation. The years 2000 and 2001 were marked by periodic blackouts, as well as the transfer of many billions of dollars from electricity consumers to producers.

In the wake of California's electricity market meltdown, a flood of analyses carried the "lessons" learned from the crisis to neighboring states and countries that had in turn been considering restructuring their electricity sectors. Many of these commentaries have been applied to reinforce pre-existing attitudes either in favor or opposed to restructuring. Those in favor of restructuring have stressed how their market is fundamentally different from California's, and therefore safe from the disruptions experienced there. Those ideologically opposed to restructuring and the aspects of deregulation that accompany restructuring policies have claimed that California proves that electricity restructuring is fundamentally misguided and doomed to failure wherever it is applied.

However, both of these perspectives miss the fundamental fact that California is remarkably similar to other markets in all but one crucial respect. While some other markets have experienced disruptions, no market has come close to the levels of market power, financial instability, and system reliability problems that characterized the California crisis. Thus perhaps the most relevant lesson to take from California's crisis is that electricity markets are neither naturally doomed to failure nor guaranteed easy success.

The factors most often cited as the causes of the California crisis are the scarcity of generation capacity (combined with rapid growth in demand), a "flawed" market design

¹ University of California Energy Institute. Email: Bushnell@haas.berkeley.edu.

that included a freeze on retail rates, and the venality of electricity producers. As I describe in this paper, the market power of producers, which was exacerbated by the tight market conditions during the summer of 2000 combined with inflexible regulatory policies at both the Federal and State level to create a financial crisis. The financial crisis in turn led to the blackouts experienced during the winter of 2000-01. These involuntary interruptions of service are what defined the period as a crisis, rather than just a period of market instability.

However, the problem with focusing exclusively on these elements is that none of them are unique to California. The focus of some analysts on the uniform-price clearing rule in the California Power exchange as the source of the state's problems is particularly curious, given the widespread use of such methods in other, less troubled, markets. Certainly other markets have had their share of tight conditions, design flaws, and venal producers. But it is fair to say that nowhere else have these factors combined with the ferocity that they did in California. The fact that they did helps to highlight the most crucial difference between California and all other electricity markets, the concentration of transactions in short-term, daily markets.

The lack of contracts or other long-term arrangements is relatively easy to identify as a major contributor to California's problems. It is more difficult to explain exactly why California market participants had so few contracts. Certainly the California Public Utilities Commission (CPUC) did not make it easy for utilities to sign contracts, but it is inaccurate to attribute the lack of contracts to a CPUC ban on such arrangements. In this paper, I describe the roots of the restructuring movement in California and give a brief overview of the tribulations of the California market during the period from 1998 to 2001. I then discuss the factors that contributed to the crucial shortcoming of the California market, the lack of contracts. These factors encompass not only regulatory policies, but the more complex question of the role of large retailers in restructured electricity markets.

California's Restructuring Plan

The market rules and regulations governing the California electricity market have been described in depth elsewhere (see Borenstein, 2002, Wolak, 2003 and Blumstein, Friedman, and Green 2002), so in this section I provide a brief overview that touches on some key elements influencing the crisis of 2000. During the early 1990's, the California electricity industry was home to two of the largest Investor-Owned Utilities (IOUs) in the United States, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE), as well as the largest municipally owned utility, the Los Angeles Department of Water and Power (LADWP), and a more modestly sized IOU, San Diego Gas & Electric (SDG&E). Aggressive implementation by the CPUC of the Federal Public Utilities Regulatory Policy Act (PURPA) had also created a substantial and influential group of non-utility, independent power producers. As of 1995, all of these utilities featured some of the highest retail rates for electricity in the continental United States.

Agitation by large industrial customers as well as non-utility generation (NUG) companies helped to spur an initiative at the CPUC to provide retail ‘choice,’ at first only to large customers but later to all retail customers. Subsequent political negotiations led to decisions to immediately grant the choice of retail providers to all customers, encourage the large IOUs to divest portions of their generation, and to create new institutions that would oversee the newly restructured market.²

California Assembly Bill 1890, which was passed unanimously in August 1996, attempted to separate the “market-making” and network reliability responsibilities into two independent institutions. The California Power Exchange (PX) was to oversee most market transactions while the role of the California Independent System Operator (ISO) was intended to be limited to operating the network with minimal intervention in the market. The PX was not a mandatory market in the fashion of the original pool in the United Kingdom, but was instead intended to eventually compete for trading volume with other potential exchanges as well as over-the-counter bilateral trades. In this sense the organization envisioned by California’s designers was remarkably similar to that later adopted in the UK in its New Electricity Trading Arrangements (see Green 1999).³

The competition for trading volume did not start with a level playing field, however, as California’s three main distribution utilities were required to utilize the PX for all of their transactions. Since these utilities retained the overwhelming majority of retail load, as well as a substantial portion of generation, this requirement helped ensure that the PX would host the dominant share of market transactions.⁴

The restructuring bill, AB 1890, also provided for an immediate 10% rate reduction, as well as the recovery by the IOUs of their “stranded costs” through a mechanism called the Competitive Transition Charge (CTC). The stranded costs were primarily composed of unrecovered rate-based expenditures on generation whose average cost was widely expected to be above the ensuing market-prices. The CTC effectively froze retail rates at 10% below 1996 levels for at least 4 years. While this constituted a rate reduction, the frozen rate level was still well above the projected cost of wholesale power. It was intended for the IOUs to collect this potentially lucrative retail margin as means of compensating them for past expenditures on generation plants (*i.e.* their stranded costs). If the amount collected by IOUs reached the estimated magnitude of stranded costs

² LADWP, which had relatively high retail rates and severe debt problems, successfully resisted efforts to grant its customers retail choice in 1996 but initiated planning for what was then viewed as the inevitable pressure for retail competition. By virtue of its retaining ownership of substantial generation capacity, however, LADWP was able to benefit from market conditions during 2000 by selling its excess power into the restructured market. Having significantly reduced its debt through these trading profits, LADWP is now held up by some as evidence of the superiority of the model of municipally owned electricity utilities.

³ Ironically, in response to its crisis, California is moving to adopt a market design somewhat similar to the UK pool, which has in turn been rejected in the UK in favor of a design similar to the one that has now been rejected in California.

⁴ The franchise on utility transactions was ended by a Federal Energy Regulatory Commission (FERC) order on December 15, 2000. The order went well beyond “freeing” utility transactions from the PX however, by effectively forbidding utilities to sell any of their generation on the PX. Thus the question of how much volume the PX might have carried had there not been regulatory barriers either for or against participation in the PX remains unanswered.

before the 4 years expired, the CTC would be removed for customers of that utility and retail rates would be freed to move with wholesale prices.⁵ The CTC could not be bypassed. Even customers who switched to a different retail provider paid the difference between wholesale prices and the frozen retail rate to their incumbent IOU.

The CPUC's need to estimate the extent of each utilities' CTC revenues (*i.e.* the spread between retail and wholesale energy prices) made it important to have an unbiased measure of wholesale prices. This contributed to the logic behind the requirement that the utilities restrict their trades to the PX. It was felt that the PX needed to be very liquid in order to produce credible wholesale prices, and that the franchise on utility transactions was needed to ensure this liquidity.

Market Structure

The three California IOUs sold off the bulk of their fossil-fired generation beginning in the Spring of 1998. Although there had been some indications of market power problems as early as August 1998,⁶ a second round of divestiture proceeded in the Spring of 1999 with little controversy despite the fact that this second round of divestiture actually increased the concentration of ownership in southern California. Table 1 shows the market ownership as of the fall of 1999. On the demand side, despite the availability of retail choice the vast majority of customers remained with the incumbent utilities. The three IOUs were nearly always net buyers on the California market, despite the fact that these utilities retained substantial nuclear and hydro capacity as well as 1990's vintage contracts with small independent power producers,

Signs of Trouble

The solid line in Figure 1 charts the monthly average unconstrained Power Exchange price through the 32 months of the PX's existence. During 1998, substantial hydro resources and abundant imports contributed to an annual average price of \$26/MWh. Prices again averaged a modest \$28/MWh during 1999. Beginning in May 2000, however, energy prices climbed to previously unseen levels and averaged \$110/MWh for the year. This was the economic phase of the crisis. Given that the utilities had negotiated a retail rate freeze at a level equivalent to about \$60/MWh, they lost about \$50 for each MWh they carried to their distribution customers during this period. The ensuing financial distress of the utilities created the physical supply crisis described below.⁷

⁵ This in fact did happen in the case of SDG&E, which ended its CTC period in June 1999. Unlike the rest of California, retail rates were not frozen in San Diego during the summer of 2000 and therefore tripled during a 4 month period from June through September. The state Legislature subsequently re-imposed a rate freeze, made retroactive to June, for small customers in SDG&E in October 2000. Bushnell and Mansur (2002) examine the impact of this price volatility on electricity consumption in San Diego.

⁶ In August 1998, prices for a "stand-by" reserve service known as replacement reserve spiked from below \$10/MWh to \$10,000/MWh. An early version of Borenstein, Bushnell and Wolak (2002) indicated at that time that significant price-cost margins were present in the energy market during August 1998.

⁷ Only PG&E and SCE were caught in the rate-freeze trap. SDG&E had declared all its stranded costs to have been collected by mid-1999 and rates in San Diego were adjusted monthly according to wholesale

Research on the competitive conditions of the California market has revealed there were signs of future trouble as early as August, 1998. Borenstein, Bushnell, and Wolak (BBW 2002), measure the extent of supplier market power, which can be expressed in terms of a margin over a counter-factual “perfectly competitive” price, for each month during the period 1998-2000. The dashed line in Figure 1 shows this estimated perfectly competitive price. Although the absolute margin pales in comparison to those seen during 2000, when expressed as a percent mark-up over competitive levels, prices during August 1998 reflected similar levels of market power to that experienced during the crisis. In fact the analysis of BBW shows that the severity of market power during 1998-2000 remarkably consistent when one controls for market demand and imports.

The critical differences between 1998 and 2000 were that imports were lower and costs were higher in 2000. Figure 2 divides the sources of energy supplied to California into 3 categories: utility self-supply (which includes pre-existing regulatory contracts), imports into the California ISO system, and supply from the newly divested merchant plants. Despite the well-publicized divestitures, the majority of electricity supplied throughout this period was actually produced by units under the control of the regulated utilities. Demand for merchant production, however, rose rapidly during 2000. The bulk of this increase is due to a dramatic reduction in imports during the summer of 2000. The criticism that California’s market failed because of a lack of investment in generation misses the fact that it was the lack of competitively-priced capacity *outside* of California, in the still regulated regions of the western U.S., that helped create the contrast in prices between 1998 and 2000. Even though imports were fewer more expensive during the summer of 2000 than earlier summers, there were no supply shortages during these high demand months.

The other major contributing factor to the economic crisis was the substantial run-up in production costs during 2000. This in turn was driven by historic increases in natural gas prices and emissions costs in California. Gas prices that had traditionally fell in the range of \$2.50/mcf, more than doubled to an average of over \$6/mcf by September 2000. Spot gas prices as high as \$60/mcf were reported in December 2000, but subsequent revelations cast doubt on the quality of gas-price data during this period.⁸ Despite likely misreporting of gas prices, it is clear that a substantial increase in prices did in fact impact the market during this period.

Thus the higher residual demand during the summer of 2000 meant that suppliers more

prices. A subsequent new rate-freeze imposed on SDG&E by the California Legislature created a regulatory “tracking” account. It was clear from the outset that responsibility for the shortfalls in this tracking account would eventually be borne by ratepayers. SDG&E was therefore able to avoid the financial distress of the larger California IOUs.

⁸ Outside of the futures contracts overseen by the New York Mercantile Exchange, there are no organized regulated exchanges on natural gas in the U.S. Regulators relied upon market data collected by survey firms who queried traders on their market activities. Subsequent investigations by FERC have revealed that much of the price data reported for California spot gas prices were based upon the market activity on the Enron On-line trading platform. It is widely believed that these reported trading prices were overstated, but it is difficult to determine the extent of the bias.

frequently enjoyed the higher price-cost mark-ups, which had been produced at high demand levels since 1998. The higher costs meant that the same percent mark-ups translated into much higher dollar margins. A nearly 50% mark-up on costs during August 1998 merely increased prices from a range of \$30/MWh to \$45/MWh. The same mark-up in July 2000 increased prices from a cost of \$100/MWh to a range of \$150/MWh. The resulting prices were more than the utilities, who were buying the vast majority of their power from the PX and ISO at these prices, could financially bear.

Technically, wholesale electricity sales were not ‘de-regulated,’ but rather under the jurisdiction of the FERC. The FERC’s approach to electricity restructuring had been to grant market-based rate authority to individual firms that could demonstrate that they did not possess undue market power. Unfortunately, the FERC’s methods of assessing the potential market power of firms were woefully inadequate (see Bushnell, 2002). Once market-based rate authority was granted, little additional oversight was given to pricing practices. The one remaining regulatory tool was a wholesale price cap, which began in California at \$250/MWh, but was raised to \$750/MWh in October 1999. During early summer 2000, the cap was lowered in a series of close and contentious votes by the ISO board.⁹

Despite the fact that the price cap was lowered first to \$500/MWh on July 1 and then to \$250/MWh on August 7, average prices were actually higher in July and August than in June. This led to the observation by some, including FERC commissioner Curt Hebert, that lowering the cap was actually increasing prices and that price-caps in general do more harm than good. Although these circumstances appear at first glance to be unusual, the result is easily explained. Prices climbed in July and August because costs rose significantly during these months. There is every reason to believe that if costs had remained stable, both the market power of producers and average prices would have declined in July and August relative to June because of the lowering of the price-cap.

The Crisis Period

After a summer where prices averaged well over \$100/MWh, PG&E and SCE appealed to the CPUC to void the transition arrangements negotiated in 1996 and raise retail rates to reflect the dramatic increase in wholesale prices. The CPUC, apparently gambling that FERC would for the first time act aggressively to further curb the market power of producers, refused the appeal of the utilities. In early January 2001, both SCE and PG&E, citing cash-flow problems, suspended payments to electricity producers.

Generation companies that were no longer being paid for their output began to shut down their facilities. This process actually started before the suspension of payments as this

⁹ During its first 3 years of existence the board of the California ISO was comprised of stakeholder representatives. This potential conflict of interest was tolerated by FERC, which had nonetheless expressed discomfort with stakeholder boards. The votes over price-cap levels laid bare the conflicts of interest and led to calls by both FERC and California’s political leaders to replace the stakeholder board. The Governor of California jumped first and replaced the board with one comprised of his appointees. Although FERC has fought this arrangement, it appears that they do not have jurisdictional authority to interfere in this regard.

eventuality had been increasingly expected and there was a two-month lag between delivery of power and final settlement of payments. Unit outages were relatively stable during the summer of 2000, averaging about 2500 MW of capacity out during June-August. Reported outages rose rapidly in the fall to average over 10,000 MW out during the November-March period of the winter of 2000-01 (see Blumstein, et al., 2002). Outages were not confined only to capacity owned by the largest firms. Over 6000 MW of cogeneration, small thermal, and renewable capacity that was under contract to the utilities was also idled by the suspension in payments.

On January 17, 2001, the California ISO initiated the first curtailment of firm load that was due to a system shortage of available capacity. Over the next 4 days there were seven total hours of curtailments, despite the fact that total demand stayed below 30,000 MW at all times. Peak demand in California had been around 45,000 MW during the summer of 2000. On February 1, 2001, the California Legislature passed Assembly Bill 1X, which, among other provisions, allowed the State government to take over the bulk of purchasing responsibilities from the two financially moribund utilities. This improved, but did not completely resolve the supply shortage until late May. The ISO was forced to curtail load in about a dozen more hours in March and May (see Blumstein, et al., 2002).

Once the financial situation was stabilized, the supply crisis was largely resolved. The economic consequences of the lack of sufficient competition remain. In June of 2001, the FERC moved to more aggressively restrict the market power of suppliers. However this change in Federal regulatory direction came after the State of California had negotiated roughly \$42 Billion in long-term power supply contracts with several suppliers. The combination of more aggressive FERC oversight, the incentive effects of the long-term contracts, and dramatically lower input costs combined to return spot prices to pre-crisis levels by the summer of 2001 as illustrated by the shaded line in Figure 1 which shows the ISO's price for real-time energy in the northern California zone.¹⁰ The improvement in spot prices only highlighted the costs of the contracts, however, which have subsequently been viewed as substantially over-priced. Disaffection over these contracts was a contributing factor in the successful drive to recall California Governor Gray Davis.

Analysis: Causes of the Crisis

The crisis, if defined more broadly to include both economic upheaval as well as physical supply shortages, was caused by a lack of competition that was exacerbated by inconsistent Federal and State regulatory policies. In short, the lack of competition led to high prices when the market got tight. The inflexibility of regulators led to the insolvency of the utilities, which in turn led to blackouts. Accusations of "withholding" during the blackout periods are probably overstated, but also beside the point. It was the market power exercised earlier, during the summer of 2000, that produced the financial conditions that led to the supply crisis. The financial damage had been done by the time the blackouts began.

¹⁰ The PX markets ceased functioning in January 2001.

Claims that a shortage of physical generation capacity was to blame are also off mark. The actual blackouts occurred during a period in which California's reserve margin is usually over 30%. Certainly more capacity during the summer of 2000 would have made the market more competitive, as it did during the summers of 2001 and beyond. However, many other reforms would have also improved the competitiveness of the market. Market simulations in Bushnell (2003) suggest that either further divestiture of suppliers, the application of long-term contracts, or the implementation of price-responsive demand would have limited market power to levels that likely would have kept the utilities solvent.

If one considers these three elements-concentration of ownership, lack of price-responsive demand, and lack of long-term contracts-that contributed to the lack of competition in California, only one element differentiates California from other regions. Supplier concentration in California was actually lower than in many other markets. Similarly, there is very little price-responsive demand in any electricity market in the world. The factor that separates California from the other markets is the concentration of market activity on the daily PX and ISO markets.

The lack of long-term contracts is relatively easy to identify as a major contributor to California's problems. What is harder to explain is exactly why transactions in the California market were so heavily concentrated in the day-ahead and real-time markets. The CPUC did discourage such transactions by utilities, but did not forbid them. Utilities did not even fully utilize the limited authority given to them by the CPUC to seek long-term contracts backed by retail rates. In understanding the California crisis, it is therefore important to better understand the interactions of retail policies with wholesale market regulations and even Federal bankruptcy laws.

Much blame for the crisis has been attributed to the requirement that the IOUs trade in the PX. There is much confusion surrounding this issue. Indeed, the FERC, in its December 2000 order, made the elimination of this requirement a centerpiece of its "remedy" for the crisis.¹¹ Analysis available at the time had highlighted the lack of long-term transactions as major contributor to California's problems.¹² However this focus on the need for contracts was distorted into a perception that the PX franchise on utility transactions was the main cause of the lack of contracts. The reality is more complicated. Certainly widespread long-term contracts and high PX volume were not mutually exclusive outcomes. The UK pool was mandatory for all participants, yet most of the transactions run through the pool were also hedged through long-term contracts for differences (CFDs).¹³

The utilities themselves, although they did not object to a relaxing of the PX franchise on their trade, have been more focused on CPUC restrictions on their long-term transactions. The CPUC did discourage utilities from negotiating long-term contracts by not allowing the terms of such contracts to factor into the calculation of the Competitive Transition

¹¹ See FERC (2000).

¹² See, for example, Wolak (2000).

¹³ See Green (1999b).

Charge (CTC). In effect this forced utility shareholders, rather than ratepayers, to bear the risk of any contracts signed by the utilities. Certainly there were no restrictions on the contracts that could be signed by the utilities unregulated marketing affiliates. The utilities have pointed to the risk of second-guessing (in the form of ex-post prudency reviews) by the CPUC as the major deterrent to their entering into long-term contracts with suppliers. At the time of this writing, the question of prudency review of contract purchases remains unresolved, and utilities have not made any commitments longer than 1 year.¹⁴

It appears that the problem is not so much one of regulatory requirements or prohibitions relating to long-term contracts, but rather one of giving buyers the proper incentives to seek out such agreements. Given that the utilities had negotiated a retail rate freeze, one would think they would have had very strong incentives to hedge their retail price risk by signing supply contracts, even if the terms of the contract would not impact the CTC. Yet the utilities chose not to sign contracts if the risks were to be borne completely by shareholders.

There are two possible reasons for this. One is hubris. The utilities simply did not believe that spot prices could possibly exceed the levels set in their retail rate freeze. The other possible explanation is that the utilities viewed the retail rate freeze only as a floor, not a ceiling. In legal filings, the utilities have taken the position that, since they maintained an obligation to serve their default retail customers, the CPUC was obligated to ensure that the utilities could recover the full cost of that obligation. If this was their belief, then they might not have felt as strong a need to hedge their retail price risk. Ratepayers would provide the utilities with their hedge. If wholesale prices went up too far, they believed the CPUC would raise rates.

Bankruptcy policies also played a role. Unregulated affiliates of the utility holding companies could and did in fact sign supply contracts that to some extent balanced the risk of the overall holding company. However, PG&E was allowed to take only the regulated utility into bankruptcy, thereby protecting the assets of the other parts of the holding company from the creditors of the utility. The ability to take the regulated utility alone into bankruptcy places a limit to the risk exposure a utility could have to wholesale price spikes. Once a utility is bankrupt, the regulator has no choice but to raise retail rates or risk supply interruption.

Retail Policies and Contracts

The trick for policy-makers then is to balance the risks created by an obligation to serve with an incentive for retailers to hedge price risks and more generally work to keep wholesale costs down. This is a problem that has vexed all electricity markets. Two general approaches show potential for solving this problem.

¹⁴ Because the contracts signed by the state government have been assigned to the 3 utilities, the need for additional long-term contracts is not pressing.

The first is truly robust retail competition. As in most markets, a group of retailers competing for customers will naturally focus on keeping down wholesale costs. If they don't, their customers will switch to those retailers that have contained costs. To date, retail competition has largely been a disappointment in most electricity markets. The UK is the only market with significant retail competition for all customer classes and, more importantly, no regulated default retail rate.¹⁵

The second approach is to maintain a default retail provider, but to have that default rate set through a market-based process. Retailers bid or negotiate to be the default provider for a period ranging from 6 months to 3 years, competing primarily on the retail rate they will offer should they become the default provider. This has become a common practice in many states of the eastern U.S. Since firms take on this obligation voluntarily through a market process, they have little justification in seeking to raise rates in the event wholesale costs rise and they choose not to hedge them. Thus it is unambiguous to both the retailer and the regulator that the default rate is both a ceiling and a floor, and the retailer has a strong incentive to sign contracts to hedge its wholesale price risk. Bankruptcy still poses a potential problem. NRG corp., which has a multiyear contract to serve as the default provider to nearly half of the retail load of Connecticut Light & Power, entered bankruptcy in early 2003 and has sought to void its retail obligation. To date, FERC has denied its petitions to do so.

One other method for ensuring a large amount of long-term contracts in a market is to simply mandate that retailers enter into contracts or other forms of long-term supply obligations. This is an approach that was contained in FERC's initial proposals for a nationwide standard market design and one that is currently favored by many parties in California. This is almost certain to achieve stable and reasonably competitive spot prices, but at what costs? The concern is that a rigid mandate for contracts simply shifts the market power of suppliers forward in time. By stripping retailers of the flexibility to shift purchases between long, medium and short-term markets, we will also deny them an effective tool in combating the market power of suppliers.

Summary

California has suffered tremendous economic disruption from the upheaval of its electricity markets over the last several years. It is unlikely that any benefits from restructuring will be significant enough to come close to making up for the losses of the last 3 years. But one cannot conclude from California that electricity restructuring is a fundamentally flawed concept. California is one of more than a dozen major markets around the world that has undergone reorganization and partial deregulation of its electricity sector. While many of these markets have suffered problems, California clearly takes the prize as the worst of the lot.

Many factors contributed to the California crisis. Generation ownership could have been made less concentrated. There was no participation by end-use demand in the wholesale

¹⁵ The retailing of electricity in the UK is not without problems. See Giuletti, Waddams Price, and Waterson, 2003.

market. The policies of Federal and State regulators were at times directly opposed to each other. However, the only factor not shared by some of the other markets in the world is the lack of contracts or other forms of long-term supply arrangements.

In taking lessons from the California crisis, we must therefore look to the reasons for the lack of long-term contracts. Although regulatory restrictions certainly played a role, the critical problem was providing large buyers with adequate incentives to seek contracts. Finding a satisfactory solution to that problem is important not just for California, but for the success of electricity restructuring in general. Many of the long-term contracts in place in other markets were established as transition mechanisms. For these markets to enjoy continued stability, it is necessary for them to find a steady-state in which contracts are freely entered into at prices reflective of underlying market conditions.

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Table 1: California Generation Ownership as of 1999

Firm	fossil	hydro	nuke	other	Gen. Max	Gen. Share
PG&E	570	3,878	2,160	793	7,400	17%
AES/Williams	3,921	-	-	-	3,921	9%
Reliant	3,698	-	-	-	3,698	8%
Mirant	3,130	-	-	-	3,130	7%
SCE	-	1,164	2,150	-	3,314	8%
Duke	3,343	-	-	-	3,343	8%
Dynegy/NRG	2,871	-	-	-	2,871	6%
Other	6,617	5,620	-	4,267	16,504	
TOTAL	24,150	10,662	4,310	5,059	44,181	

Figure 1: California Electricity Prices

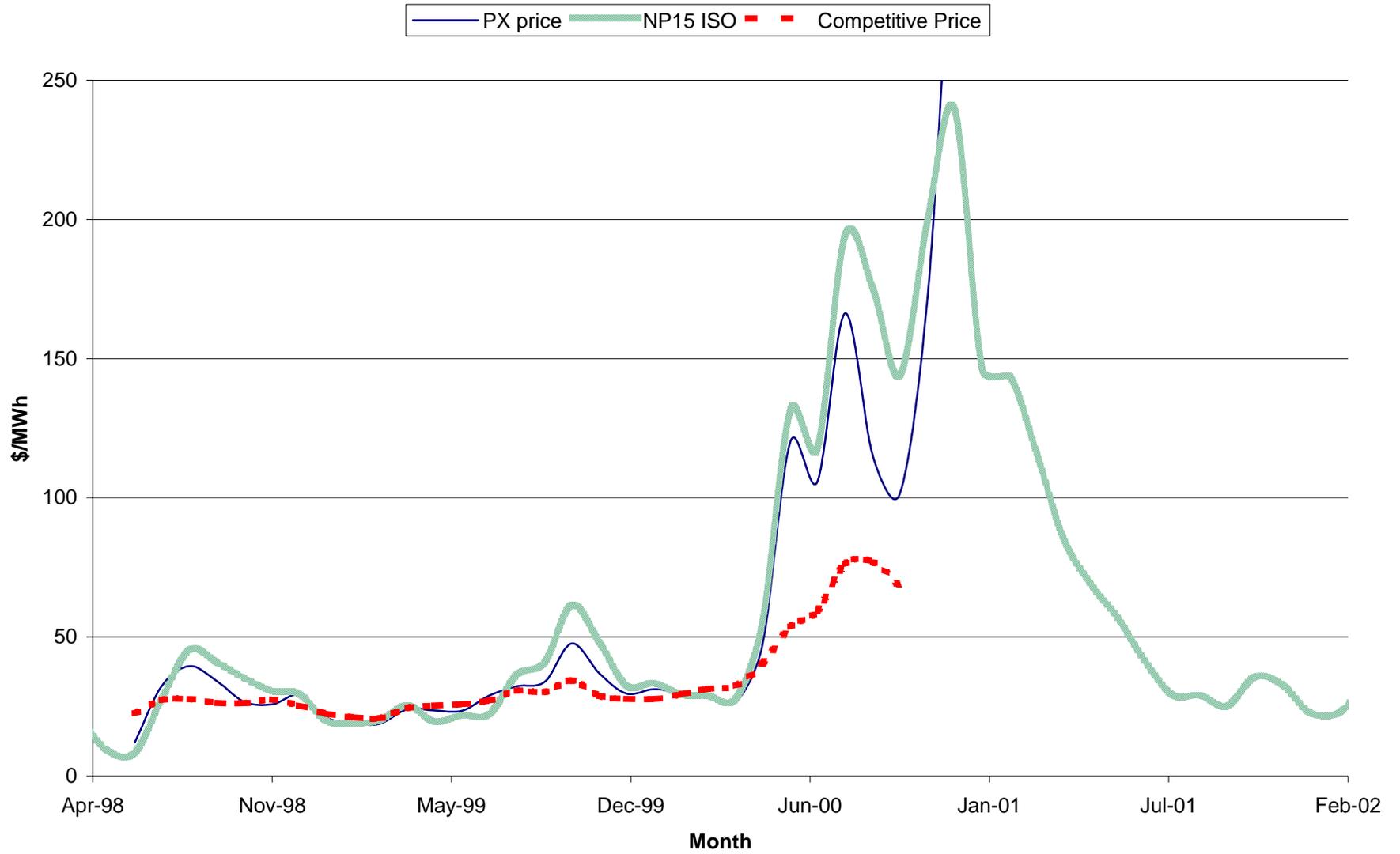


Figure 2: California Electricity Supply Sources

