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What went wrong in California's electricity market?

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Abstract

The California electricity market reform promised to deliver reliable service at low and stable prices. Frequent capacity shortages and the ensuing rolling black-outs, price spikes, and large price volatility since Summer 2000 raise a simple but substantive question: what went wrong? The answer to this question will help countries contemplating electricity market reform not to commit similar mistakes. We find the answer by identifying the major factors that have turned the California dream into a nightmare. Such factors include poor market design, market power, sustained demand growth not matched by new capacity, rising marginal cost, and financial insolvency. Proposed remedies include an alternative market settlement process, long-term contract, fast licensing and siting process for new generation and transmission, conservation and energy-efficiency, distributed resources, rate options, and debt restructuring. The California experience suggests that a reversible regulatory reform is a safe alternative to an irreversible market reform.

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1. Introduction

California is the seventh largest economy in the world. Its electric system consists of about 1,000 generation facilities with 55,000 MW capacity with diverse fuel sources, including gas and oil, nuclear power, hydro, biomass, geothermal, wind, solar and cogeneration. California has 40,000 miles of transmission lines that connect the load-serving utilities to national and inter-national power grids. Up till Summer 2000, California's electric service was reliable, comparable to the level witnessed in developed countries. Although California's average retail electric rates at about US$0.09/kWH were among the highest in the US, they were not excessive when compared to those in the developed economies in Europe (e.g., France, UK, and Germany) and Asia (e.g., Japan and Hong Kong).

Something went terribly wrong on the road to reform of California's electricity market. As roads go, this one was well marked, with signposts that promised "this way to reliable service at low, stable prices." When the journey began in 1996, most participants – regulators, utilities, legislators, and consumers – believed that the expedition was heading in the right direction and that the path ahead was relatively free of obstacles. Somewhere along the way, however, the expedition went astray. Eventually the financially drained participants ended up far from their planned destination in a land of rolling blackouts and surging wholesale prices.

Exemplified the California market reform failure are the following unprecedented events. On February 1 2001, the state's wholesale spot market – the California Power

Exchange – closed its doors due to lack of trading.[1] On April 6 2001, the largest utility in the state declared bankruptcy. On May 15 2001, the North American Electric Reliability Council projected rolling blackouts of over 260 hours in Summer 2001, ten times worse than the 1-day-in-ten-years generation reliability planning criterion commonly used by the electricity industry in a developed economy. During the 4 ½ month period of January 17 – May 31 2001, the state government had spent $7.6 billion to buy wholesale power at an average price of US$270/MWh because the two largest electric distribution companies could not pay their wholesale purchase bills (*Megawatt Daily* June 18, 2001). The state purchase will continue and the ensuing cost will drain the state treasury and diminish the funding for such government programs as education and social welfare. To mitigate the impact of the power purchase on the state's cash flow and stabilize the future purchase cost, the state will issue $13.4 billion in bonds in August 2001 to finance long-term purchase contracts whose average price is around $69/MWh over a 10-year period.

These events chill the international trend of electric market reform and make one wonder what had California done to its electric sector. Equally important is what lesson can be learned by countries contemplating reforming their electric sector. At the very least, the lesson should convey a clear message of what not to do in an electric market reform. For this reason, this paper addresses the question, "What went wrong in California's electricity market?"

2. California Market Reform

[1] The evaporation of trading was caused by the Federal Regulatory Energy Commission's Order issued on December 15, 2000 to relieve the three utility distribution companies from a must-buy requirement imposed by the California Public Utilities Commission.

Prior to the generation divestiture associated with the 1998 market reform, over 75% of California's generation capacity were owned or controlled by three integrated investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SD&E). These IOUs met retail consumption by delivering power via their transmission and distribution (T&D) networks. Subject to the rate-of-return regulation, the IOUs charged their retail customers average-cost rates that included the return on and of their past investments. Electric service was reliable and of good quality, even though California had the highest retail electric rates in the nation.

Dissatisfaction with the rate-of-return regulation led the California Public Utilities Commission (CPUC) to rely on market forces in the provision of generation. In early 1990s, the CPUC adopted competitive bidding for new capacity to meet projected demand. In 1995, the CPUC ordered the IOUs to unbundle their integrated systems, so as to pave way for open access to the IOUs' T&D by competitive generators to supply electricity consumers. In 1996, the California legislature passed Assembly Bill 1890 that shaped the California electricity market as we know today.

The California electricity market generally mirrors the generic model of electricity market reform that typically create the following markets and organizations:

- A competitive wholesale energy market in which buyers and sellers transact by making demand and supply bids.
- An independent system operator who implements the wholesale market energy transactions by managing the high-voltage transmission owned by the newly created regulated T&D companies.

- Regulated T&D companies that descend from the formerly integrated utilities. Subject to the rate of return (or price cap) regulation, these companies own the T&D networks and must provide open access to all users.
- A retail market whereby retail customers can freely choose their preferred energy suppliers.

The first two years of California electricity market operation were uneventful. Wholesale energy prices were relatively low and service reliability was comparable to the pre-reform level. But January 16, 2001 was not a good day for the California electricity market (*Megawatt Daily* January 17, 2001). A severe capacity shortage prompted the California Independent System Operator (ISO) that operates the California grid to declare Stage 3 emergency with rolling black-outs. The day-ahead energy price at the major California hub (North Path 15) was $250/MWh, nearly 10 times the average January price a year ago. Southern California Edison (SCE), the large utility with over four million customers, suspended its scheduled payments of $586 million to the California Power Exchange (PX), qualifying facilities that supply power under pre-market-reform contracts, and debt holders.[2] The California Legislature passed emergency assembly bill AB IX to create a state power authority that will seek to procure long-term supply contracts at or below $55/MWh. If successful, the contracted supply will be sold at cost to PG&E, SCE, and SDG&E.

These events epitomize the misery that began in Summer 2000. As shown in Fig. 1, the ISO declared Stage 1 and 2 emergencies much more frequently in June –

[2] As will be described below, the PX market is the wholesale energy market in California created by AB1890 that legislated the California market reform.

September 2000 than the prior months.[3] The average PX market prices during these emergency hours reached as high as $750/MWh. The price spikes in June prompted the ISO to lower the price cap for real time energy from $750/MWh to $500/MWh on July 1, and then to $250/MWh on August 7, 2000.

INSERT FIG. 1 HERE

Fig. 2 shows that the monthly average of the hourly PX market prices spiked in June – September 2000, notwithstanding that the daily gas price and GWh sales were stable throughout April 1998 – September 2000. The high wholesale market prices since Summer 2000 and the retail rate caps imposed in 1996 by AB1890 caused PG&E's and SCE's financial insolvency. This prompted the California Public Utilities Commission (CPUC) to authorize in January 2001 a temporary $10/MWh surcharge on the retail sales of PG&E and SCE (*Megawatt Daily* January 5 and January 8, 2001).

INSERT FIG.2 HERE

SDG&E's financial health was unaffected by the high wholesale market prices because its retail rate freeze was removed in mid-1999, after recovering its stranded generation cost (i.e., SDG&E's generation fixed cost, less the proceeds from selling its generation assets). Unfortunately, SDG&E's retail customers were not as lucky. In Summer 2000 they paid more than twice their 1999 electricity bills (Kahn, Lynch [1]).

[3] The emergencies entail public appeals for voluntary load curtailment and the IOUs cutting non-firm services.

Figs. 1 and 2 paint a grim picture that greatly differs from the September 23 1996 press release from the Governor's Office when former Governor Pete Wilson signed AB1890 that legislated the California electricity market reform:[4]

> "Every time a resident of this state flicks on the electric switch, they pay 40% more than residents across the United States…. The legislation I am signing today will end that by ushering in a new era of competition, making California the first state in the nation to dismantle this electricity monopoly. This landmark legislation is a major step in our efforts to guarantee lower rates, provide customer choice and offer reliable service, so no one is literally left in the dark."

Summer 2000 proves that former Governor Wilson's prediction is wrong. The rolling black-outs since January 2001 eliminate any hope that the prediction will come true any time soon. The vast difference between the 1996 hope and the 2001 reality raises a simple but substantive question: What went wrong in California's electricity market?

As noted in former Governor Wilson's press release, California's retail rates charged by the three IOUs in the early 1990s were 40% higher than the national average. The California average retail rates were above $90/MWh, dwarfed the out-of-state wholesale market prices of approximately $17/MWh at the California-Oregon-Border (COB) (Woo, Lloyd-Zannetti, Horowitz [2]). Even after accounting for the approximately $30/MWh charges for transmission and distribution (T&D), there was a

[4] AB1890 (p.3): "It is the intent of the Legislature to ensure that California's transition to a more competitive electricity market structure allows its citizens and businesses to achieve the economic benefits of industry restructuring at the earliest possible date, creates a new market structure that provides competitive, low cost and reliable electric service, provides assurances that electricity customers in the new market will have sufficient information and protection, and preserves California's commitment to developing diverse, environmentally sensitive electricity resources."

$43/MWh difference between the average wholesale price of $17/MWh and the IOUs' average embedded cost rate of $60/MWh for generation.

Large industrial users pushed for access to the low-priced wholesale energy. The CPUC had also been pursuing policies of competitive provision of electricity (e.g., competitive bidding for new plants to meet projected demand). This led to the CPUC's 1994 recommendation of market reform that would begin in 1995 with retail rate unbundling. In 1996 the California Legislature passed AB1890 that shaped the market reform to be implemented by January 1, 1998; even though actual market opening was delayed until April 1 1998 (CalPX [3]).

"Every constituency group endorsed AB1890, except one consumer group that took no position." (Kahn, Lynch [1, p.7]). The key elements of AB1890 include:

(a) A retail rate freeze at the 1996 level so that the difference between the average embedded cost for generation and the wholesale market price would help pay for the IOUs' stranded generation cost. The freeze for an IOU would last till March 31, 2002; unless the IOU had fully recovered its generation stranded cost before this date.

(b) An immediate rate reduction of 10 percent for residential and small commercial ratepayers. The financing of the rate reduction is through the issuance of "rate reduction bonds" to be repaid by a charge on retail consumption.

(c) Continued funding for low-income ratepayer assistance programs, public purpose programs for public goods research, development and demonstration, demand-side management and renewable electric generation technologies.

(d) Incentives for the IOUs to divest their fossil-fuel generation units.

(e) Retention of ownership (but not control) of T&D assets by the IOUs.

(f) Creation of a non-profit PX to operate the wholesale energy markets.

(g) Creation of a non-profit ISO to manage and operate the California grid.

The retail rate freeze under (a) helped PG&E and SCE to recover the bulk of their stranded generation cost, until Summer 2000 when the wholesale market prices spiked and financially strained these two IOUs. The same provision ended SDG&E's retail rate freeze in mid 1999. The 10% retail rate decrease under (b) has benefited small uses, even though the benefit will be offset by future payments for retiring the rate reduction bonds. Continued funding for the various programs under (c) is accomplished by a small public good charge on retail consumption.

The remaining elements of AB1890 defined the California electric market structure. The incentive for generation divestiture under (d) was effective. By May 1999, the three IOUs completed their sale of 17,683 MW of capacity (CalPX [3]). However, they continue to own their hydro and nuclear units. The new generation owners now control 40% of the California's total generation of about 55,000 MW (Khan, Lynch [1]). The IOUs under (e) transferred control of their T&D assets to the ISO created under (g).

INSERT FIG.3 HERE

As indicated in Fig. 3, there are two PX markets created under (f). The PX day-ahead market is for energy delivered the next day. The PX day-of market applies to energy for same day delivery. As the largest scheduling coordinator in the state, the PX

accepts demand and supply bids from PX market participants, including the IOUs. The market clearing price (MCP) in each market is determined by the intersection of the aggregate demand and supply curves in that market. As the PX MCP at this point does not consider transmission congestion, it is referred to as the unconstrained MCP.

The PX submits the balanced schedules (with demand equal to supply) to the ISO. Absent transmission congestion, the ISO implements the PX schedules, along with the balanced schedules of other scheduling coordinators. The ISO's implementation serves to meet final consumption. If transmission congestion is expected, the ISO applies adjustment bids to the schedules to equate demand and supply within each of the 25 congestion zones.[5] This yields zonal MCPs whose pair-wise difference is the congestion charge between two zones (Hogan [4]; Woo, Horowitz, Martin [5]).

Even though the schedules submitted to the ISO are supposedly balanced, a forced plant outage and an unexpected surge in demand can destabilize the grid. The ISO manages the system imbalance using a set of ancillary services that include regulation, spinning reserve, non-spinning reserve, replacement reserve and real time energy. The ISO buys ancillary services competitively via day-ahead and day-of auctions designed to elicit potential sellers' private marginal cost information (Chao, Wilson [6]).

3. What Went Wrong?

A cursory review may lead one to believe that the California market reform should be able to provide reliable electricity at low and stable prices. After all, the PX-ISO market design marries the economic model of market competition and the engineering model of optimal dispatch. Competitive bidding among PX buyers and

sellers should theoretically yield an efficient allocation of electrical energy (McAfee, McMillan [7]). Competitive auctions of ancillary services should enable the ISO to perform least cost dispatch (Chao, Wilson [6]). Zonal pricing of transmission should efficiently allocate the limited transmission capacity (Hogan [4]; Woo, Horowitz, Martin [5]). Surging zonal MCP and the associated excess profits should attract new generation at the locations with dwindling supply or rising demand. But the reality of the events that have occurred since Summer 2000 obliterates such a belief. An examination of the California market reform failure yields the explanations given below.

3.1 Poor market design

The PX-ISO market design is poor with several major flaws:

Must-buy requirement. The IOUs are required by the CPUC to buy from the PX and ISO markets. Their hourly demands are highly price insensitive because (a) PG&E's and SCE's retail customers face the retail rate freeze, (b) SDG&E's retail customers are now billed at the monthly average of the hourly prices, and (c) hourly electricity demands by individual end-users are price insensitive (Lawerance, Aigner [8]; Aigner [9]). This must-buy requirement, when coupled with highly price insensitive demands, implies that a mild shortage can cause large price spikes (Borenstein [10]). Also, the requirement reduces the likelihood of a seller losing sales and profit due to high prices. This encourages capacity withholding by the few sellers that dominate the California electricity markets.[6]

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[5] Each zone is so defined that transmission constraint is unlikely within the zone.

[6] Even though the 12/15/2000 order by the FERC removed the must-buy requirement, the damage was done in that PG&E and SCE had already incurred large wholesale power purchase cost that were $8+ billion more than they received from retail sales.

No forward contracting. A corollary of the must-buy requirement is the IOUs total dependence on the PX and ISO *spot* markets. They cannot enter into forward contracts to ensure reliable supply at fixed prices, notwithstanding that risk hedging is common in portfolio management (Woo, Horowitz, Hoang [11, 12]). If the IOUs were to enter into bilateral contracts with wholesale suppliers in Mid-Summer 2000, they could have made long-term purchase at a price around $60/MWH.

Sequential markets. The PX and ISO markets are sequential. If a seller makes a high price bid and fails to sell in the day-ahead markets, it can easily make up the lost sales and profit in the day-of and real-time markets. This encourages capacity withholding by sellers in the day-ahead markets.

Market power. About 10 sellers determine the PX market prices (CalPX [13]). This is partly due to the fact that the IOUs' plants were sold in packages to increase the auction proceeds and expedite the divestiture. Because of the must-buy requirement and price-insensitive demands, exercise of market power by the few dominant sellers results in market prices that far exceed the competitive levels (Wolak, Nordhaus, Shapiro [14, 15, 16]).

3.2 Rising marginal costs, in-state shortage, and financial insolvency

Other factors have also contributed to the California's electricity market fiasco; and they are not directly related to the market design flaws.

Rising marginal costs. The California market is inter-connected with out-of-state markets like COB and Palo Verde (PV). Market inter-connection implies that California market prices should reflect the out-of-state market prices for they measure California's in-state

marginal (opportunity) cost. Fig. 4 shows that the California price spikes are partly due to rising marginal costs.

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To understand why the out-of-state market prices correctly measure California's marginal costs, consider the following cases:

- Case 1: If there is no inter-state transmission congestion, the sellers in California can import from the out-of-state markets for resale in the California markets. As well, the in-state sellers can export to the out-of-state markets. Arbitrage among traders implies price convergence; and out-of-state market prices accurately reflect the marginal opportunity costs of California sellers (Woo, Horowitz, Hoang [11, 12]; Woo, Lloyd-Zannetti, Horowitz [2]).
- Case 2: If there is inter-state transmission congestion, the congestion typically limits power import into California (CalPX [13]). Because of the physics of transmission of alternate current, the import constraint does not prevent an in-state seller from exporting to the out-of-state markets. Hence the marginal opportunity cost for electricity sold in California markets is the out-of-state market prices.[7]

In-state shortage. Virtually no new in-state capacity came on line in the last decade, despite California's robust economic growth of 3%-6% per year since 1994. New

[7] To be sure, the inter-state transmission congestion could have limited power export from California. Export from California typically occurs on cold winter days when the electricity demand in the Pacific Northwest exceeds the generation (mostly hydro) capacity in that region. But transmission constraint for power export seldom occurs because the Pacific Northwest's power import is small when compared to the 3,700 MW transmission capability between California and the Pacific Northwest. As a result, export limitation is an unlikely event.

capacity addition in California was 672 MW over the past five years, while Texas had added 5,700 MW over the same period (*Newsweek*, January 22, 2001). The 7-year lead-time required to build a plant in California will not help relieve the shortage anytime soon (*Restructuring Today*, January 10, 2001). New plant development has also been hampered by the fact that the largest and most likely buyers (i.e., the IOUs) cannot enter into long-term contracts that would reduce a developer's revenue dependence on spot market sales. A volatile revenue stream raises the developer's financing cost and can make new plant development uneconomic. Hence the in-state shortage is not a short-term phenomenon and will exist for the next 2-3 years.

Financial insolvency. Both PG&E and SCE are now financially insolvent (*Restructuring Today*, January 22, 2001). Though few sellers would publicize their reluctance of selling into the California markets, I suspect that the two IOUs' default risk exacerbates the shortage problem.

4. Remedies

What are the remedies? The major ones are discussed below:

Alternative market settlement. The Federal Energy Regulatory Commission (FERC) in its November 11, 2000 proposed order recommends an alternative settlement scheme that would replace the single-price settlement rule used by the PX and ISO. The alternative scheme would set a $150/MWh cap on bids that set the market clearing prices in the PX and ISO markets and applies the pay-as-bid for bids above $150/MWh. Wolak, Nordhaus and Shapiro [17] find the remedy ineffective for sellers can enter into bilateral deals not subject to the proposed scheme. As well, the pay-as-bid rule may not induce

truthful revelation of marginal cost and therefore cannot effect efficient dispatch (Wolfram [18]).

Long-term contract. The FERC's proposed order recommends eliminating the must-buy requirement imposed on the IOUs. If adopted, the recommendation would pave the way for the IOUs to enter long-term supply contracts at fixed prices. Long-term contracts can also promote power plant development (*Restructuring Today*, January 22, 2001). Wolak, Nordhaus and Shapiro [17], however, express reservations about the remedy: (1) it may require prudence review, and (2) it may dry up the liquidity in the PX.[8] The first reservation is mitigated by the fact that competitive bidding and regulatory review have been practiced in California long before the market reform. The second reservation is mitigated by the fact that an alternative spot market structure (e.g., Automatic Power Exchange) can and will emerge in response to the changing needs of the market participants.

Fast licensing and siting process. It takes 2-3 years to complete plant construction in Texas (*Restructuring Today*, January 10, 2001). The 7-year lead-time in California is a major barrier to market entry. Even if state regulators commit to expedite the process, local opposition can derail new plant construction. For instance, Calpine's proposed 600-MW gas-fired MetCalf plant in San Jose was put on hold because of the City Council's opposition that reflected the "not in my backyard" mentality of the local residents. Thus the effectiveness of this remedy remains to be seen.

Conservation, energy-efficiency and distributed resources. Rising demand unmatched by capacity additions is the primary cause for the price spikes and shortages. If California

[8] The PX closed its door on February 1, 2001 due to the lack of trading caused by the FERC's imposition of the proposed order on December 15, 2000.

and its neighboring states were awash with surplus capacity (as was the case in the late 1980s and early 1990s), market prices would likely be low. Since large in-state supply additions will not occur in the immediate future, California must seek solutions with shorter lead times. These solutions are conservation, energy-efficiency, and distributed resources (Orans, Woo, Horii [19]; US Congress [20]; Ball, et al [21]). The public good funding provision in AB1890 can help accelerate the implementation of these solutions.

Rate options. The California problem is exacerbated by the lack of customer response to wholesale market price spikes. Mandatory real time pricing for all retail customers is impractical because of high transaction costs and low customer acceptance. As a result, rate options with voluntary participation are useful alternatives. Such options include curtailable service (Woo [22]), voluntary time-of-use pricing (Woo, Orans, Horii, Chow [23]), and voluntary real time pricing (Woo, Horowitz, Chow [24]). By conveying market price information to the participating customers, these options achieve demand reduction during high price hours, thus decreasing the market prices, alleviating capacity shortages, and mitigating market power.

Debt restructure. It is easy to opine that PG&E and SCE should go bankrupt for their accepting the retail rate freeze and voluntary sale of power plants. But bankruptcy by these two IOUs can only magnify the reliability problem that Californians currently face. Stage 3 emergency was in effect four days (January 16-19, 2001) in a row. Customer outage cost estimates in Woo and Pupp [25] indicate the rolling black-outs must have imposed substantial costs on the California economy. But willing sellers demand financially solvent buyers. Hence the state government, the wholesale suppliers, the ratepayers, and the IOUs must reach common grounds on how to restructure the debt.

Without debt restructuring, the shortage situation can only worsen in the days to come. An example of this approach is the state government's proposal of taking over the two IOUs' hydro units in exchange for the state's assumption of the IOUs' debt (*Megawatt Today*, January 23, 2001). Whether the state's proposal will be accepted by the principal parties, however, remains to be seen.

5. Conclusion

What can we learn from the California experience? I believe the answer is that if electricity market reform is not done in an environment of surplus capacity, many sellers and easy market entry, it will not yield the desired outcome of reliable service at low and stable prices. The form of market structure (e.g., pool vs. bilateral market) and related issues (e.g., locational vs. non-locational transmission pricing) that have dominated the literature prior to the California crisis are less important.

In light of the California experience, I propose a list of questions that must be answered prior to reform implementation. By no means exhaustive, the list serves as a reminder that market reform can easily fail as a panacea for high electricity costs and rates and poor service reliability and quality. This list is as follows:

- Will there be excess capacity after the reform?
- Will many sellers compete for sales to many buyers?
- Will market entry be easy?
- Can new capacity be built quickly?
- Will there be sufficient transmission available under open access by competitive sellers and buyers?

- Will there be active forward and spot trading that facilitate price discovery and risk management?
- Will electricity end-users be able to see and respond to wholesale price changes?
- Will the market design be relatively simple but have sufficiently strong and effective rules against gaming and market power abuse?
- Will service quality and reliability improve after the reform?
- Even if the answers to the above questions are affirmative, will electricity consumers be better off than the status quo?
- Can the projected benefits of a market reform be obtained via other means?

Finally, I must caution that electricity market reform is highly risky and irreversible. Once the power plants owned by the formerly integrated utilities are divested, it is very difficult, if not impossible, to turn back. The California experience suggests that a reversible regulatory reform is a safe alternative to an irreversible market reform. An example of a successful regulatory reform is performance-based regulation (PBR) with price caps to ensure real rate decline and incentive for superior service quality and reliability. Even if PBR will not achieve all of the highly touted benefits from a California-style market reform, PBR's downside risk is minimal. This is one of the primary reasons supporting our PBR recommendation for the Israeli electric sector (Tishler, Woo, Lloyd [26]).

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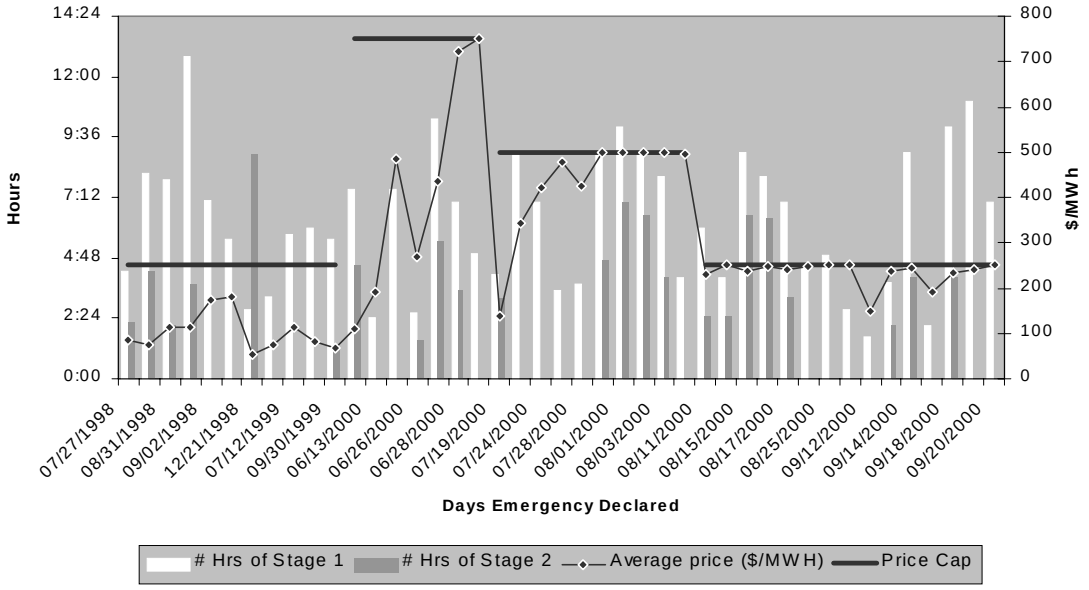

Fig. 1. Emergency history, price caps and average PX unconstrained day-ahead price during the emergency hours. Data source: www.calpx.com and www.caiso.com.

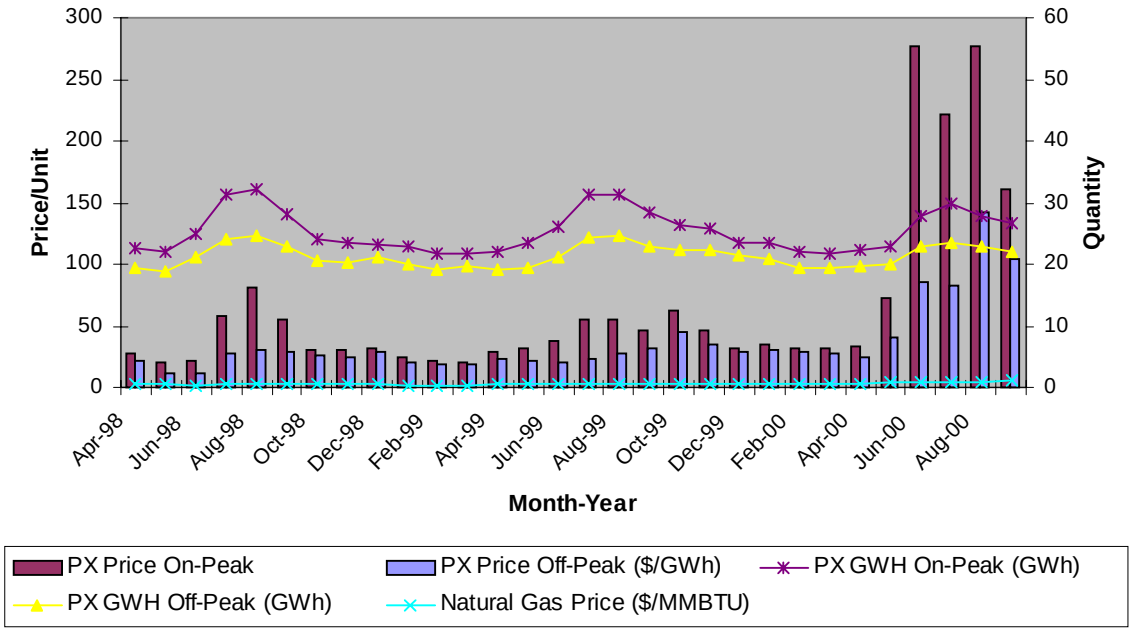

Fig. 2. Monthly average of hourly PX day-ahead unconstrained prices and market clearing GWh by time-of-use (TOU) and monthly average of daily natural gas prices during 1 April 1998 – 30 September 2000. We define the PX on-peak period as 12:00 – 18:00, working weekdays and the off-peak period as the remaining hours. The left vertical axis measures prices in $/unit and the right vertical axis measures quantity. The bars indicate the PX prices ($/MWh) by TOU. The two top lines indicate the market clearing GWh sales by TOU. The bottom line portrays the monthly average of daily natural gas prices ($/MMBTU). Data source: PX prices and GWh from www.calpx.com; and daily natural gas prices from PG&E.

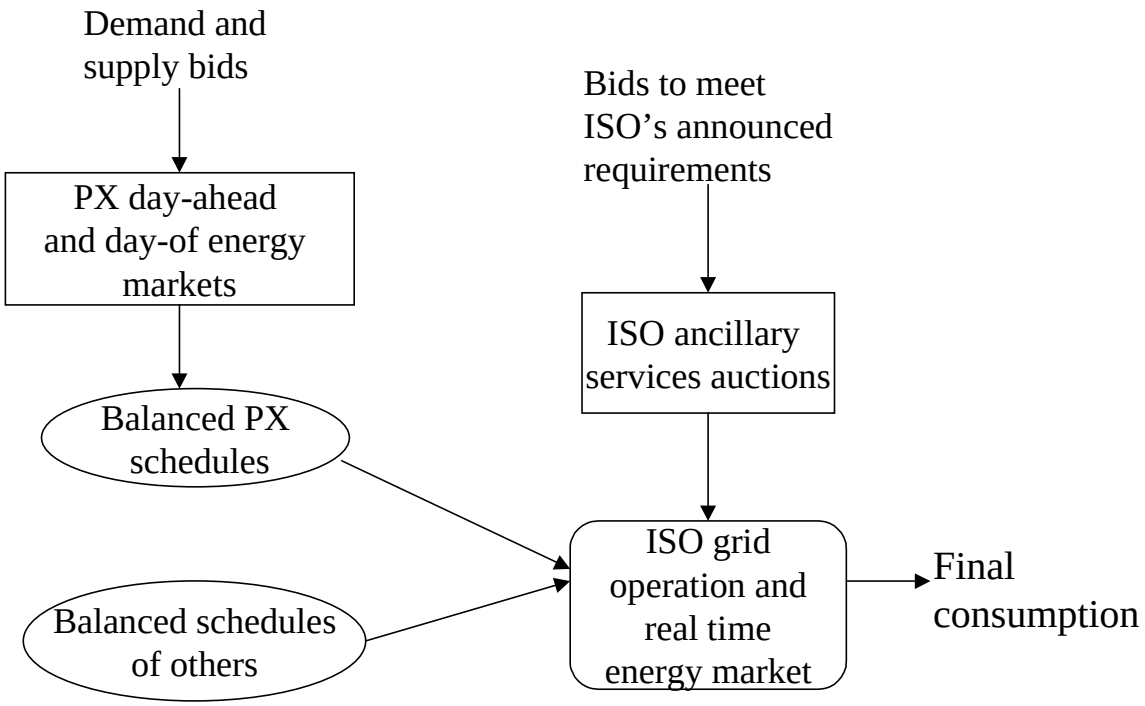

Fig. 3. California electricity market structure.

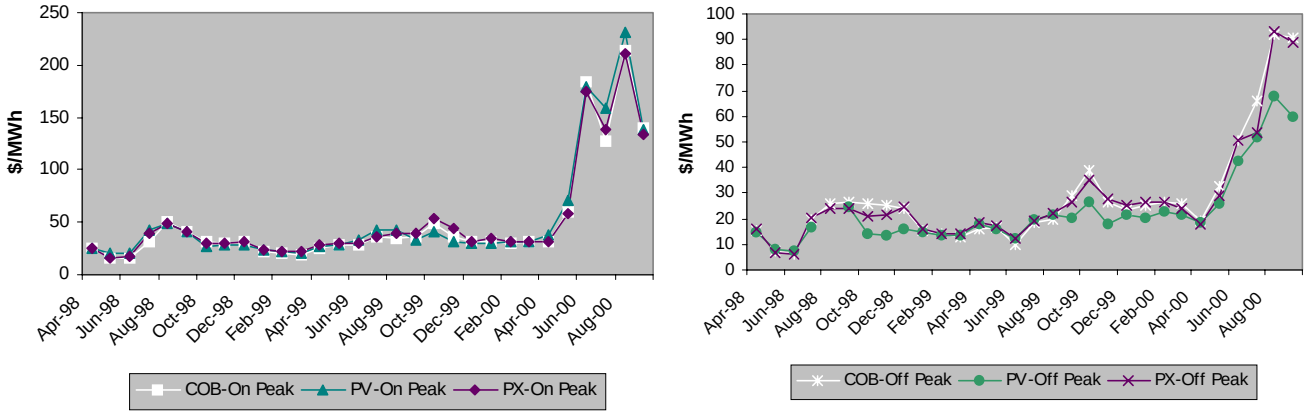

Fig. 4. PX, COB, and PV monthly average prices for 04/01/98-09/30/00. The out-of-state markets define the on-peak period as 06:00-22:00, Monday – Saturday and the off-peak period as 22:00 – 06:00, Monday – Saturday. For easy comparison, the monthly average of the hourly unconstrained PX day-ahead prices are computed using the same period definitions.