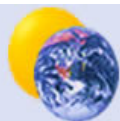


Lessons from a Comparative Analysis of California and PJM Electricity Restructuring Models

**John Byrne
Young-Doo Wang
Jung-Min Yu**

**Center for Energy and Environmental Policy
University of Delaware**

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Lessons from a Comparative Analysis of California and PJM Electricity Restructuring Models¹

1. Electricity Restructuring in the United States

Federal and state government regulations in the early part of the 20th century in the U.S. created monopoly franchises that were encouraged to take advantage of scale and integration economies through the legal guarantee of exclusive rights to produce and sell electricity in a defined service territory. In return for the monopoly franchise, investor-owned utilities (or IOUs) were subjected to governmental control of operating procedures, prices, and investment in order to protect consumers from potential monopolistic abuses.

It was not until the Public Utility Regulatory Policies Act of 1978 (PURPA) that significant changes were made to the U.S. regulatory regime. Departing from conventional “rate of return” regulation, PURPA introduced the idea of supply-side competition (via Non-Utility Generators) and spurred demand-side efficiency initiatives. PURPA established a class of non-utility generators comprised of small power producers and co-generators and required utilities to buy electricity from these qualifying facilities (QFs) at rates not to exceed a utility’s avoided cost (CEEP, 2000). Especially, PURPA empowered state regulators to encourage utilities to evaluate options such as purchasing power from “qualifying facilities” and paying customers to invest in more efficient equipment. This reform led to so-called “integrated resource planning” in which utilities increasingly considered both demand-side and supply-side options to meet the service requirements of their customers (CEEP, 2000).

The Energy Policy Act of 1992 (EPACT) built on PURPA’s innovations and began regulating development of wholesale competition. EPACT required transmission-owning utilities to guarantee non-discriminatory open access to the transmission grid for all parties. The issuance of Orders 888 and 889 by the Federal Energy Regulatory Commission (FERC) in 1996 finally marshaled national support behind electricity deregulation at both the wholesale and retail levels.

¹ This paper has been prepared for the Korea Development Institute, Knowledge Partnership Program, for its June 20-21 conference *Electricity Restructuring: International Experiences and Lessons for Korea*. Information originally published in a 2002 report by the Center for Energy and Environmental Policy for the Korea Electric Power Corporation, New York Office is included in this paper.

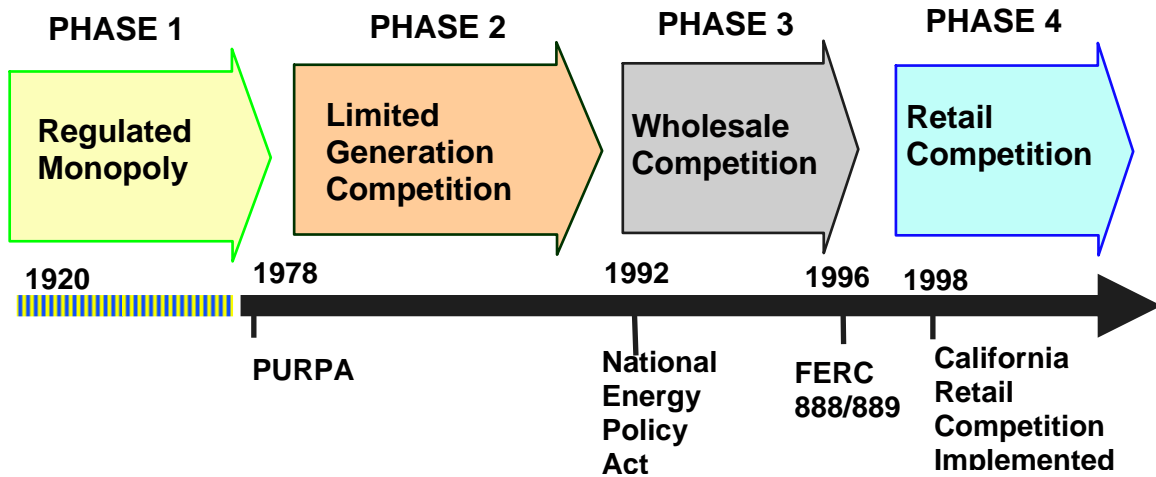


Figure 1 U.S. Electricity Restructuring Timeline

Order 888 required utilities to provide open access to their transmission networks for the transfer of electricity, to construct additional capacity to meet transfer needs, and to un-bundle their transmission activities from their other power plant operations (CEEP, 2000). Order 889 directed transmission-operating utilities to create networks to openly share information pertaining to transmission capacity, prices and ancillary services needed to conduct trades. Utilities were ordered to obtain information required for wholesale trades through a standard open access, same time information system (OASIS) in order to prevent market power abuse (CEEP, 2000).

With this background, we explore below the emergence of deregulated electricity markets in the U.S. by focusing on the origins of, models for and experiences with wholesale and retail competition in two parts of the country – California (the first U.S. state to open its utility sector to retail competition) and the mid-Atlantic region of the U.S. east coast (comprised of the states of Delaware, Maryland, New Jersey, Pennsylvania – and more recently, additional states – that receive transmission service from the PJM Interconnection and have their wholesale bidding markets managed by PJM).² The very different origins of deregulation, models developed to manage competition, and experience with deregulation of the two jurisdictions offer important lessons for power sector reform policy.

² For an overview of the PJM Interconnection and its services and operations, please visit its website: <http://www.pjm.com/index.jsp>.

2. Overview of Electricity Restructuring in California

2.1 Background

Before restructuring, California's electricity was supplied by a combination of large private utilities (owned by investors) and municipal power companies (owned by cities and counties). About 70 percent of Californians were customers of the state's three large vertically-integrated investor-owned utilities (IOUs) - Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E). These three utilities owned and operated generation, transmission and distribution facilities to provide for electricity needs of all consumers in their exclusive franchise areas. Prices, costs, investments and service obligations were regulated by the California Public Utilities Commission (CPUC).

In early 1993, the CPUC launched a comprehensive review of the structure and performance of California's electricity industry. It was motivated primarily by pressure from industrial consumers to reduce electricity prices (which were among the highest in the U.S., and much higher than those in neighboring states in the West).³ High electricity prices in turn were blamed on failures of the existing system of regulated vertically integrated monopolies. The typically cited failures included high costs of nuclear power plant investments, expensive long-term contracts with qualifying facilities (QFs), excess generating capacity, costly and ineffective regulatory institutions. There was broad agreement that the existing industry structure and regulatory system needed to be reformed. Independent power producers (IPPs), whose emergence was supported by EPACT and who were eager to expand their business opportunities, also encouraged the state's initiatives to restructure electricity market.

In April 1994, the CPUC articulated what was then viewed as a radical reform program for the electricity sector in a report known as the "Blue Book." It was built around a new industry structure in which the production of wholesale electricity from existing generating plants and the entry of new plants would be deregulated and their power sold in a new competitive wholesale market. Retail consumers would have the choice of using the transmission and distribution wires of their local utility to obtain "direct access" to these new competitive wholesale markets or continuing to receive power from their local utility at prices reflecting the costs the utilities incurred to buy or produce it.

In early 1996, after two years of debate among interest groups about the proposed reforms and transition arrangements, the CPUC issued its long-awaited restructuring decision. Later that same year, the California legislature passed a restructuring law (Assembly Bill 1890) that largely followed the architecture delineated by the CPUC's restructuring order, but that also included a number of significant refinements.

³ In 1996, the average energy price was 75 percent higher than the average price in the 10 other western states. California's industrial energy prices was 7.0¢/KWh, whereas Washington and the U.S. average were 2.9¢/KWh and 4.6¢/KWh, respectively (EIA, 1998).

2.2 Features of the California Restructuring Model

2.2.1 Institutionalization of Competition

Unbundling of vertically integrated IOUs

The three large investor-owned utilities were required to divest themselves of at least half of their fossil-fuel-powered generating plants.⁴ However, they retained their nuclear and hydro-electric plants, and existing long-term contracts. By September 2000, the effects of the required divestiture of generating assets were clearly visible. Power plants owned by the utilities provided just 28 percent of the electricity in the state's restructured power market, down from 40 percent the previous year. Meanwhile, the share from NUGs in the state (independent power generators, including qualifying facilities) reached 58 percent, up from 40 percent in 1999 (CBO, 2001).⁵

In order to resolve the stranded cost issues associated with uneconomical nuclear power investments and long-term contracts, provisions were made for competition transition charges (CTC) and incentives to divest generating assets and to renegotiate QF contracts. Stranded costs associated with most utility generating assets—approximately 28 billion dollars—had to be recovered within a four-year transition during which retail rates would generally be frozen at their 1996 levels. If stranded utility generation costs were recovered sooner than in four years, then the rate freeze would end immediately and retail prices were expected to “fall” to reflect prevailing wholesale market conditions. It was assumed that wholesale power prices would be significantly below the prevailing price of generation service reflected in regulated retail rates.⁶

Retail “customer choice” (Retail wheeling)

Effective in 1998, consumers were given a choice of continuing to buy power from their traditional utility or purchasing it from other competitive electricity service providers (ESPs)—with the new supplier delivering power over the utility’s distribution system and consumers being billed separately for power and distribution services. If they did not choose an ESP, consumers could continue to receive “default service” from their local utility distribution company (UDC). Although many people believed that consumer choice was among the plan’s most significant features and that most retail customers would gradually migrate to ESPs during the four-year transition period, only 3 % of customers actually switched suppliers while prices remained frozen.

⁴ Fossil fuel includes natural gas, coal, and oil, but in California most of the fossil-fuel plants burn natural gas.

⁵ Municipal utilities were not required under AB1890 to participate in the restructured electricity market and most continued to serve the needs of their customers by generating their power or with other market transactions initiated at their own discretion (CEC, 2002).

⁶ The possibility that wholesale prices could be higher than the regulated price of generation service reflected in prevailing retail prices was not considered. In their testimony before the CPUC, utility representatives uniformly assumed that wholesale prices would be lower as a result of deregulation.

Open Access

IOUs were required to provide open access to their transmission and distribution networks to competing generators, wholesale marketers, and ESPs.

New Entry

The reform program “deregulated” entry of new generating capacity. Independent power producers were free to apply for environmental and siting permits and to sell power to eligible wholesale and retail buyers.⁷

Wholesale Market Institutions

In order to support sales by competing generators and purchases by distribution companies, ESPs and marketers in competitive markets, in a way that respects the special physical attributes of electricity and the need to maintain the reliability of the transmission network, the reform program created two important institutions to operate public markets and manage congestion using market mechanisms.

The California Power Exchange (CALPX) was established as California’s “official” energy market. The CALPX conducted energy auctions that established energy prices and schedules on both a day-ahead and an hour-ahead basis. The role of the PX was to provide a highly responsive market for the buying and selling of electricity.

The California Independent System Operator (CAISO) was created to operate the transmission system and generally ensure system reliability. The utilities were required to transfer control (but not ownership) of their transmission networks to the nonprofit corporation. The CAISO was also responsible for running various energy balancing, ancillary service, and congestion management markets and ensuring stable system performance.

Restrictions on Long-term Contracts

California's Public Utility Commission generally interpreted the restructuring plan as incompatible with allowing utilities to contract for long-term power supplies outside the CALPX and the CAISO. That restriction applied to two types of long-term arrangements: contracts that the utilities made in the futures market and contracts in which independent power producers that had purchased the utilities’ generating assets agreed to supply the utilities with a certain amount of electricity in the future (CBO, 2001). These requirements imposed on the IOUs participating in the CALPX market

⁷ However, the reform program did not reform the process for obtaining siting approvals from the California Energy Commission (CEC) and local authorities. These processes had been designed for an era when utilities engaged in long term planning, carried large reserve margins, and long and controversial approval processes were built into the planning and investment process. Moreover, since few new plants had required CEC siting approvals in many years, the approval processes were “rusty” and understaffed. Generators trying to build new power plants soon found that obtaining necessary siting permits would be a slow and frustrating process (Joskow 2001).

effectively precluded utilities from entering into long-term contracts with independent power producers.

2.2.2 Pricing Rules and Restrictions

Market-based pricing

Prices of electricity generation, transmission and distribution came to be determined on the basis of market activity, rather than the “cost basis” price used by the CPUC for a monopoly provider. Under traditional regulation, utilities were allowed to charge prices that recovered their costs and gave investors a large enough return to attract ample capital for the utilities.⁸ With the introduction of competitive wholesale markets, however, wholesale power producers were given the authority to sell at “market-based rates” determined in PX-conducted auctions. Each UDC’s default service energy price, charged to non-residential customers who did not choose an ESP, was effectively set equal to the wholesale spot market prices for power determined in the CALPX auction, adjusted for physical losses, plus avoidable billing and metering costs.⁹

Retail Price Discounts and Freeze

Residential and small commercial customers received an immediate 10% price reduction from prevailing 1996 regulated prices, financed by the cost savings from securitization. The maximum bundled retail prices for these customers were frozen for up to four years at 10% less than the prices in effect in 1996.

Transmission Charges and FTRs

Transmission charges were divided into 3 categories: access fees, which were intended to recover the sunk costs of transmission investments, and congestion charges and loss compensation, both of which reflected the operational costs of using the grid.¹⁰ A single access rate was charged for customers in each transmission owner’s service area. For congestion management, California adopted zonal pricing in which transmission usage charges are based on the difference in zonal costs.

In order to help transmission customers avoid the risks associated with congestion management, a binding contract was introduced called a “firm transmission right” (FTR) that entitled the holder to receive scheduling rights and a stream of revenues from potential congestion charges across pre-established congestion interfaces. FTRs were

⁸ Economists have long pointed out that such regulation encouraged utilities to over-invest in electricity generating capacity because the cost of additional capacity could be more than covered by higher electricity prices (see, e.g., Averch and Johnson, 1995).

⁹ Competitive residential rates were deemed unrealistic in the early phase of deregulation because few residential users could self- or co-generate and therefore might face discriminatory pricing (because their demand is less elastic than that of business customers).

¹⁰ In most cases, “transmission owner” means a spin-off of each of the three IOUs, although municipal utilities and other smaller transmission owning entities could enter the CAISO framework.

allocated through annual auctions and could be traded in the secondary market through bilateral contracts.

Performance-based Regulation (PBR)

To replace traditional cost-of-service regulation of residual monopoly distribution services, these schemes typically involve the application of a variant of a “price cap” mechanism. These mechanisms are designed to give distribution utilities incentives to control costs and to relieve the regulatory agency of the need to reset distribution rates frequently. California adopted a PBR policy regarding so-called ‘captive’ residential customers.

No Capacity Payments

Unlike the Pennsylvania-New Jersey-Maryland (PJM) Interconnect (see below) and certain other power pools, generators received no capacity payments or payments for startup costs. Consequently, generators were required to recover their fixed and capital costs through direct payments for energy on PX sales, as well as through the energy and capacity charges in the ISO ancillary services markets.

No Regulatory Reserve Margin Policy

California required CAISO to secure reserves through ancillary service markets via auctions in lieu of the conventional regulatory mechanism of a specified reserve margin. Unlike the PJM (which has maintained a margin requirement and a penalty payment structure for its violation— see below), California’s restructuring policy allowed the market place to decide the level and price to be paid for system’s reserve capacity.

2.3 Operation of California’s Competitive Market

2.3.1 The California Power Exchange (CALPX)

California created a separate public market for trading energy on a day-ahead and day-of basis.¹¹ California’s PX was a non-profit corporation organized under the laws of California. The existence of a separate PX was a distinguishing feature of the California restructuring strategy. Technically, the CALPX was a scheduling coordinator for the ISO.¹² It was, however, actually much more important, because roughly 87 percent of the electricity under the authority of the ISO was scheduled through the CALPX during its

¹¹ Since the PX stopped operations on January 2001 and eventually filed for bankruptcy, the discussion that follows reflects the structure of the market as it was originally designed and, more or less, operated until early 2001.

¹² A Scheduling Coordinator (SC) was any wholesale entity that had been licensed to schedule power on the CAISO network and agreed to abide by its operating rules and payment obligations. Non-utility generators and wholesale marketing intermediaries could register as SCs with the CAISO. The marketing affiliates of the owners of the divested generating capacity, larger municipal utilities, vertically integrated utilities in other states in the WSCC (as well as Canada and Mexico), and wholesale marketers without generating assets at all were registered as SCs.

first year. The Governing Board members represented all participants and consumers and were appointed by the Oversight Board.¹³

The PX had two markets—the day-ahead market and the hour-ahead market where it calculated a market-clearing price for electricity. The three major utilities (PG&E, SDG&E, and SCE) were required to buy and sell their energy through the PX. They were required to place all of their day-ahead demand for their default service customers through the CALPX on an hourly basis. They had to bid all of the energy supplied from any generating units they continued to own or power supplied to them under pre-reform long term contracts into the CALPX as well. All other participants (e.g., marketers, municipal utilities in California or utilities in other states) could trade electricity using a variety of means (e.g., bilateral contracts or electronic trading).

The day-ahead market auctioned power in advance of the actual flow of electricity. By 7 a.m. on the day prior to the actual energy flow, each participant in the day-ahead market submitted its supply or demand bids for each hour of the subsequent day. The CALPX took the hourly day-ahead supply and demand bids and “stacked” them to form aggregate supply and demand curves for each hour. The hourly market clearing price was then determined by the intersection of these aggregate supply and demand curves. The CALPX would notify market participants of each hour’s market-clearing price by no later than 8:10 a.m. All buyers paid the uniform market clearing price, and all sellers were paid this price. If there was no congestion, the market-clearing price represented the price actually paid by CALPX participants for buying or selling energy. Winning suppliers took on a financial obligation based on the market clearing price in each hour, but not a physical supply obligation. The CALPX then forwarded its schedule which specified the amount of energy it would supply and demand for each hour of the day to the CAISO. Other non-CALPX participants would submit schedules with the CAISO through scheduling coordinators (SCs) as part of the day-ahead scheduling process.

The CALPX Day-of market operated in a manner similar to the day-ahead market, except that the market consisted of three separate auctions for separate hourly segments of the day. Auctions were conducted at 6 a.m. for hours 11 a.m. to 4 p.m., at noon for hours 5 p.m. to midnight, and at 4 p.m. for hours 1 a.m. to 10 a.m. As time approached the actual hour of the power flows, CALPX participants would have better forecasts of their actual load commitments. The Day-of market allowed CALPX participants to more closely match their schedules with forecasted conditions, so they would be less reliant on the real-time energy balancing in the market. The market clearing price was determined the same way as in the day-ahead market. Since the participants were trading largely based on unexpected deviations in their schedules, the

¹³ In order to oversee the CAISO and the CALPX, California AB1890 created the Oversight Board, which was comprised of 5 members; three members were “appointed by the Governor of California from a list provided by the California Energy Resources Conservation and Development Commission and the Public Utilities Commission” with confirmation by the Senate of California (AB 1890, Article 336 §1). Two members were appointed by the Assembly and the Senate, respectively (AB 1890: Article 336 §2 and §3).

volume of electricity traded in the hour-ahead market was much smaller than volumes transacted in the day-ahead market (Earle et al, 1999).

2.3.2 The California ISO (CAISO)

As a non-profit corporation, CAISO governed the operation of the transmission networks owned by the three major investor-owned utilities (IOUs) in California and coordinates these operations with interconnected transmission systems in the WSCC. CAISO was subject to regulation by FERC under its rules governing transmission operators (Orders 888 and 889), as well as a set of “independence” criteria applicable to Independent System Operators. The governing board members of CAISO were composed of California residents and market participants and appointed by the Oversight Board. According to AB1890, a simple majority of the board would consist of persons who are themselves unaffiliated with the utilities.¹⁴

CAISO was responsible for managing transmission congestion through its day-ahead scheduling process and in real time. CAISO accepted hourly schedules from SCs including the PX on a day-ahead basis and an hour-ahead basis, and then managed the operation of the system in real time based on market information it received from sellers and buyers and the physical constraints of the network. If no problems were detected, then each SC's schedule was deemed final.

However, when the ISO detected congestion between zones (inter-zonal congestion) within the system, then it turned to congestion charges to relieve constraints.¹⁵ SC scheduling would include supply from one zone to another congestion payments to CAISO would be levied during periods of congestion. In order to calculate congestion charges, the ISO used adjustment bids from SCs and determined a marginal price to use for the congested interfaces between zones. Payments were equal to the difference in the clearing prices on either side of any congested interface multiplied by the quantity being scheduled across it. The payments were then rebated to the entities that held firm transmission rights on the congested paths (Joskow, 2001). Once CAISO had calculated this capacity charge and determined which SC schedules would be adjusted, it issued the final day-ahead schedules by 1:00 p.m. These schedules state the amount of energy each SC was responsible for producing and consuming (Earle et al, 1999).

¹⁴ On July 17, 2002, FERC ordered CAISO to adopt a two-tier form of governance by January 1, 2003. The top tier would consist of an independent, non-stakeholder Board which would have sole decision-making authority in all matters, while the lower tier would consist of an advisory committee (or committees) of stakeholders.

¹⁵ California adopted a “zonal” congestion management system which allowed separate market clearing energy and ancillary services prices to emerge in Northern and Southern California (separated by a transmission path called “path 15”). In early 2000, CAISO created a third congestion zone (ZP 26) that lies between the original Northern and Southern zones. The Pennsylvania-New Jersey-Maryland (PJM) ISO and the New York ISO have implemented full nodal pricing systems.

To ensure short-term reliability of the network and to respond to unanticipated changes in demand or plant outages, CAISO also oversaw procurement of all ancillary services in its jurisdiction. CAISO procured ancillary services through its day-ahead and hour-ahead markets for the four types of ancillary services (see Table 1). These markets selected generators that agreed to hold generating capacity with specified physical attributes (primarily adjustment speeds and communications capabilities) in reserve to be available in a particular hour to respond to instructions from CAISO to supply energy. Generators selected in these ancillary services auctions were to be paid availability payments equal to a uniform hourly market-clearing reservation price to hold the capacity in reserve and then paid for the energy they would supply if they were subsequently called on by the ISO to supply energy.

CAISO operated a real-time energy balancing market into which generators could submit bids to supply more energy or to reduce the energy they have scheduled to supply to the network. CAISO relied upon real-time energy bids of those units selected to provide capacity in the day-ahead and hour-ahead ancillary services markets, as well as supplemental energy bids received 45 minutes before the start of the hour (Earle et al, 1999).

Finally, CAISO was responsible for developing protocols for financial settlements between generators supplying to the network and agents for consumers using energy from the network, effectively determining energy and ancillary services imbalances and the associated financial responsibilities of each SC that schedules facilities operated by CAISO (Joskow, 2001). It is important to note that CAISO continues to operate even after the CALPX's operations were suspended (the latter matter is discussed later in this report).

Table 1 Four Types of Ancillary Services

Ancillary Service	Definition
Regulation Reserve	Unloaded generation capacity that can be activated within 30 minutes that is online and subject to automatic generation control, and thus capable of responding in an upwards and downwards direction.
Spinning Reserve	Unloaded generation capacity that is synchronized to the system and that is capable of being loaded in 10 minutes.
Non-spinning Reserve	Unloaded generation capacity (or load that is capable of being interrupted) that can be synchronized to the system and reached within 10 minutes.
Replacement Reserve*	Unloaded generation capacity (or curtailable demand) that can be synchronized to the system within 60 minutes.

* FERC does not view replacement reserve as an ancillary service.

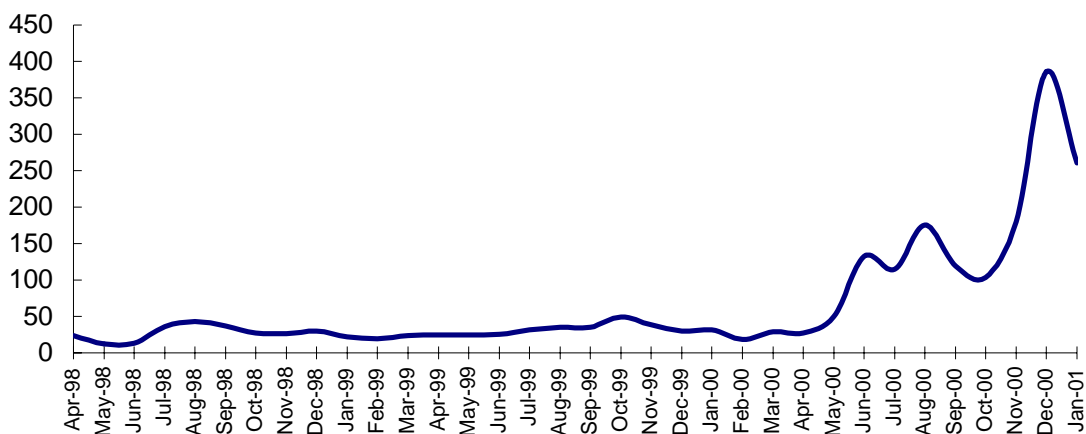
Source: Earle et al, 1999.

2.4 Market Performance before the State's Crisis: 1998-1999

The new competitive wholesale and retail electricity markets began operating in April 1998. The PX was scheduled to begin operation on January 1 of that year, but due to several important problems involving software glitches, the market couldn't open on time. Despite poor coordination between the CALPX and CAISO in the early stages of California's deregulation initiative, the markets had a fairly successful start with no large problems in their operation through the end of 1999. As these markets evolved and participants gained more experience, however, a number of issues became increasingly important. The limitations placed on the CAISO's ability to play an active role in energy markets and through forward contracts led to numerous problems well before the more visible meltdown that began in May 2000.

2.4.1 Wholesale Market Performance

In terms of wholesale prices of electricity, California's competitive wholesale market experienced relatively stable and reasonable prices for power close to pre-reform projections between April 1998 and April 2000. Figure 2 displays the average monthly day-ahead price in the PX for the period April 1998 through January 2001 when the PX stopped operating. Prices prior to May 2000 roughly reflect expectations at the time the restructuring process began.¹⁶



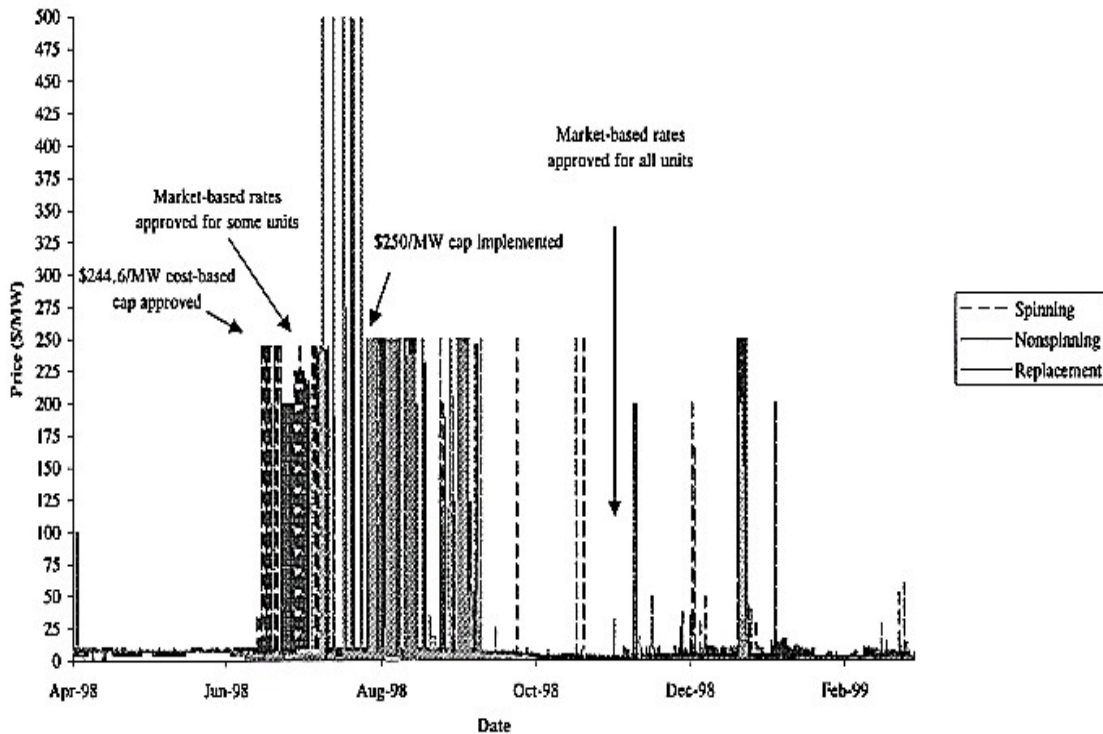
Source: Joskow, 2001.

Figure 2 California PX Day-Ahead Prices (\$/MWh: Weighted Average 7 x 24)

The ancillary services market, however, was plagued by episodes of extremely high availability payments, particularly during the summer of 1998 (see Figure 3). Until July 1, 1998, all entities bidding into the ancillary services markets were subject to FERC cost-based rates. Before June 10, 1998, nearly all of these rates were below \$10/MW.

¹⁶ It was expected that average hourly wholesale prices would start at about \$25/MWh and rise to about \$30/MWh as excess capacity was gradually dissipated.

Consequently, the ancillary services capacity prices were below \$10 for nearly every hour. Starting on June 10, 1998, however, a price cap was set for some of the divested units from the “Big Three” utilities in California at \$244.60/MW. On June 11, 1998, the maximum price often hit \$244.60/MW. On June 30, 1998, FERC issued its first ruling granting market-based rates to some units for ancillary services. FERC also ruled that all units could bid market-based rates for replacement reserves. Soon after this ruling, reserve prices jumped above the previous high of the capped level of \$244.60/MW. On July 13, 1998, replacement reserve prices reached levels of \$9,999/MW. The ISO, realizing that there were deficiencies in its market, on July 14, 1998, implemented a \$500/MW cap for reserves. The cap was decreased to \$250/MW on July 24, 1998. For September through November 1998, a period when load levels were lower, the capped price occurred much less frequently (Earle et al, 1999).



Source: Earle et al, 1999.

Figure 3 Day-Ahead Ancillary Services Prices, SP15 (Apr. 1, 1998 to Mar. 31, 1999)

There were episodic market power problems that emerged from time to time at high-demand periods. During low and moderate demand conditions, day-ahead prices were reasonably close to estimates of marginal cost, and energy markets seemed to be quite competitive. When demand neared peak levels, however, it was clear that the wholesale market was clearing at prices far above the marginal cost of the most expensive generators in the region. During peak periods, most demand was satisfied with purchases in the CALPX spot market. Since there is virtually no real demand elasticity in these markets, generators realized that as demand grew and supply tightened, a small amount of capacity withheld from the market, even with moderate levels of

concentration, could lead to large price increases. However, prior to summer 2000, the effects of horizontal market power on prices were relatively small overall, and the supply-demand imbalances, when they emerged, were short-lived (Joskow, 2001).

2.4.2 Retail Market Performance

An important component of California's restructuring program was to give retail customers "choice." If customers did not choose an ESP, they could continue to buy generation service from their local utility at a regulated default service rate. However, the default service pricing formula effectively capped retail prices for generation service at about \$65/MWh for up to four years. Accordingly, it is inaccurate to characterize the retail market reform in California as "deregulation." Wholesale market prices were deregulated, subject to FERC's ongoing supervision and responsibilities under the Federal Power Act. But retail prices at least in the residential sector were fixed for up to four years. The utilities retained the obligation to buy power in the new wholesale market for retail consumers who did not choose a competitive retail supplier and to resell it to them at a fixed price regardless of its cost for up to four years.

Despite predictions that retail consumers would quickly switch to ESPs offering lower priced service, in reality only about 3% of retail electricity consumers, representing about 12% of demand, switched to ESPs, leaving the utilities with the responsibility to provide "default service" for about 88% of electricity demand. As it became clear that they had a large unhedged retail default service obligation, the utilities (in early 1999) requested authority to enter into longer term forward contracts with wholesale suppliers in order to hedge their short positions.¹⁷ The CPUC initially rejected these requests and subsequently sharply restricted the kinds of forward contracts that utilities could sign and delayed required approvals of those forward contracts that met CPUC criteria. As a result, a large fraction of California's electricity demand was being served through the utilities' purchases in an increasingly volatile wholesale spot market, while the utilities were selling at a regulated, fixed retail price.

Eventually, this circumstance would lead to severe financial strain (to be discussed in Section IV). But it should be noted that had deregulation advocates argued, at the time of the policy debate in California (i.e., 1992-1996), that deregulation could lead to higher retail prices, it is unlikely that the reform would have passed.¹⁸

¹⁷ Stranded cost and other payments for the investments of the "Big Three" utilities' nuclear and hydroelectric plants provided a partial hedge. However, this amounted to only about 12,000 MW of capacity, of which 6,000 MW of hydro was energy-limited.

¹⁸ California's AB1890 passed unanimously, on the clear assumption that retail prices would decrease as a result of market-based pricing.

3. The California Power Crisis

California's power crisis can be characterized as the coincident conditions of very high wholesale prices, escalating financial problems for utility providers, electricity consumers and taxpayers, and unprecedented rolling blackouts over an extended period of time. This section provides an overview of the defining features of the crisis. It examines several explanations of the causes of the crisis, with a focus on those that analyze California's policy design.

3.1 Characteristics of the California Power Crisis

3.1.1 High Wholesale Prices

Assembly Bill 1890 (AB1890) won unanimous support from the both houses of the California legislature in 1996. From April 1998 through May of 2000, both the California Power Exchange (CALPX) and the Independent System Operator (CAISO) operated smoothly and electricity prices in the PX market remained fairly low. Wholesale prices ranged between 1¢ and 3.5¢/kWh during off-peak, to 4.5¢/kWh at peak periods (Brennan, 2001). Staged emergencies were nonexistent; they occurred only during summer months, and three occurred, at most, in any one month (Brennan, 2001).

The price of wholesale electricity sold on the PX started soaring in the spring of 2000, reaching unprecedented levels over the remainder of the year. From June through July 2000, wholesale electricity prices increased on average 270% over the same period in 1999. By December 2000, wholesale prices on the CalPX cleared at \$376.99 per MWh, over 11 times higher than the average clearing price of \$29.71 per MWh in December 2000 (EIA, 2002).

With one exception, high wholesale prices did not result in residential retail price increases. Only San Diego Gas & Electric Company (SDG&E) could pass through the high wholesale prices to residential customers, because it recovered its "stranded costs" through competition transition charges (CTC) before the end of 1999. As a result, unlike other customers of California IOUs (notably PG&E and SCE), customers of SDG&E were exposed to the price volatility of the PX market. Indeed, customers of SDG&E had to pay two-three times higher prices than usual. To stop the steep increase in retail price, the California legislature established in August 2000 a cap on increases to protect SDG&E customers.

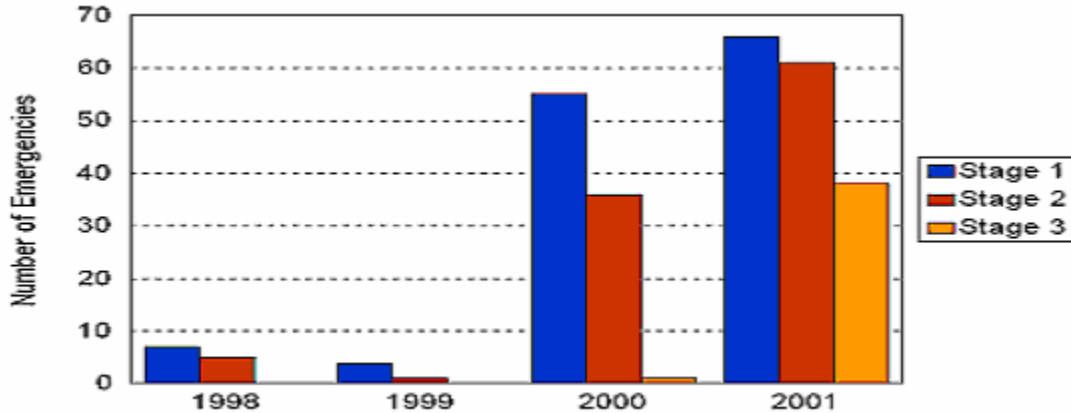
3.1.2 Financial Problems of IOUs

Due to the retail rate freeze, IOUs could not collect enough money from retail customers to pay for spiking wholesale power prices at the CALPX. In fall 2000, IOUs began to request CPUC support for a rate increase, but the Commission rejected their request. By the end of December 2000, PG&E and SCE collected \$11 billion less from their customers than they paid to buy wholesale power from the PX (Sioshansi, 2001). When IOUs stopped payment for power, the PX no longer could provide a market for the

transaction of power and ceased operating on January 2001. Southern California Edison (SCE) defaulted on \$596 million worth of payments to power companies and bondholders on January 16, 2001. After the announcement of default by SCE, rolling blackouts hit northern California on January 17 and 18. The California government passed legislation that allowed a state agency, the Department of Water Resources (DWR), to assume the responsibility of purchasing power under bilateral long-term contracts for sale to PG&E and SCE.

3.1.3 Frequent Emergency Alerts

Even though high wholesale prices persisted throughout summer 2000, shortages in supply occurred, causing unprecedented emergency alerts. In 1999, there were 5 Stage 1 alerts (reserves below 7%) and 1 Stage 2 alert (reserves below 5%). In 2000, the number of Stage 1 and 2 alerts increased to 55 and 36, respectively, and there was one Stage 3 alert (reserves below 1.5%). In 2001, matters worsened considerably. Stage 1 alerts climbed to more than 60; Stage 2 alerts reached 60; and disturbingly, there were nearly 40 Stage 3 alerts. Figure 4.1 summarizes the experience.



Source: California Independent System Operator, Cited from EIA (2002)
Figure 4 California's Declared Staged Power Emergencies 1998-May 22, 2001

3.2 Causes of the Crisis

There are several explanations for the California electricity crisis. Among them, a set of factors contributing to the physical imbalance of supply and demand and inadequate market rules to handle this problem is generally agreed among industry leaders and market advocates. However, given the fact that municipal utilities that chose not to participate in the CALPX were not as adversely affected by the crisis, it can be suggested that market design flaws described below are likely to have played a role in the crisis.

3.2.1 Mismatch: Wholesale and Retail Electricity Prices

While wholesale electricity prices and natural gas prices were deregulated, retail electricity prices were fixed for residential customers of the IOUs until they had recovered their stranded costs through the competitive transition charge (CTC) or by December 31, 2003, whichever occurred first. Hence increases in wholesale power costs could not be passed through to retail users, thus discouraging rapid and broad-scale energy conservation¹⁹ and exposing electricity distributors to huge potential losses under their obligation to serve their customers.²⁰ This flaw does not become serious unless wholesale prices rise above retail rates, which they were not expected to do at the time that the reform was being introduced. This flaw may be only transitory, but it contributed to the onset of the crisis during the transition period.

3.2.2 Lack of Adequate Capacity Resources

The UDCs were not obliged to contract for capacity, nor were generators recompensed specifically for providing capacity. Long-term forward contracting of energy by the UDCs was also not allowed, and so they were not able to develop a risk-minimizing power portfolio. During 2000, they acquired only about 6% of their energy from forward markets, in contrast to 34% from their own generating plants and 60% from other suppliers in the CALPX market. Finally, the lack of forward energy markets for some years ahead suppressed the price signals that would have helped the distributors and investors in generating capacity to assess the need for new capacity.

3.2.3 Wholesale Demand Inelasticity

Because of their obligation to serve the demands of their captive customers, the UDCs could not refuse to buy power in the CALPX market. A relatively modest tightening of the supply-demand balance, in the absence of wholesale demand elasticity, produced summer price spikes in the CALPX market. UDC 'price inelasticity' is a result of market design: they were obligated to buy and, at the same time, had little leeway to avoid the volatility of the CALPX spot market in order to fulfill their obligation to captive customers. Permission to use forward markets and complete longer term contracts could have created the needed flexibility to moderate the effects of UDC 'price inelasticity.'

¹⁹ If wholesale prices were allowed to serve as price signals to consumers in California, some believe that the problem was fixable (Sweeny, 2002). The higher retail prices would have encouraged conservation that would have been a key to placing downward pressure on the wholesale prices. In this regard, some argue that real-time metering would allow customers to adjust their demand to higher prices. In fact, no California customers were billed on real-time meters, and only commercial and industrial customers pay demand charges (which reflect the load demands made by users on the supply system)

²⁰ Ultimately PG&E declared bankruptcy; SCE was on the verge of bankruptcy but eventually negotiated a settlement with the CPUC.

3.2.4 Price Caps on Bidders

Facing virtually no supply bids in the real-time balancing energy market to meet system needs, the CAISO was authorized by FERC to impose during 2000 progressively lower “soft” price caps on bidders, starting at \$750/MWh during the summer and dropping to \$250/MWh by the end of the year. Payments made by the UDCs above the price cap would be subject to scrutiny and cost-justification by CAISO (but only after the fact). These levels would amply cover the costs of power generation under normal trading conditions, but \$250/MWh was insufficient to cover even the variable operating costs of the older power plants during the periods of very high gas prices and high costs of NOx emission permits. The situation appeared to provoke generators into raising their bids for supply during off-peak periods to recover their losses under the price caps during peak periods.

3.2.5 High Dependency on Spot Market

Since the CALPX capped prices in the day-ahead energy market at a much higher level (\$2,500/MWh) than the CAISO’s cap in the real-time balancing market, the UDCs have kept down their demand purchases in the day-ahead market by under-scheduling their own units during hours when price spikes would otherwise be likely to occur. They had to do this to keep the price in this market below the cap in the real-time balancing market, thus effectively capping the rate they would pay at the lower level of the latter. As a result, purchases on the real-time balancing spot market constituted a higher proportion of total traded energy in CALPX (20–30% of the total energy procured) than in other U.S. states and other countries that have forward contracts in their power markets. Usually, a balancing market handles less than 5% of total trade. This feature appears to have contributed significantly to the large volatility in prices at CALPX.

3.2.6 The Failure of Retail Competition

Less than 2% of California’s retail electricity users left their original providers (i.e., the UDCs) for alternative Energy Service Providers (ESP). Most ESPs exited the California market by late 1999 after their failure to attract customers. The failure to develop retail competition in California resulted from a policy of charging residential users a default price equal to the wholesale power price, rather than the retail market price, and by allowing the UDCs the right to provide default service.²¹ The amount by which the default service price exceeds the wholesale price dictates the level of customer savings and supplier earnings, which are fundamental drivers of retail competition. Generally, the higher the default price relative to the wholesale price, the more intense the competition and switching to new suppliers.

²¹ Default service refers to electricity supply provided to those residential customers that are not receiving service from a competing supplier.

3.2.7 Market Manipulation

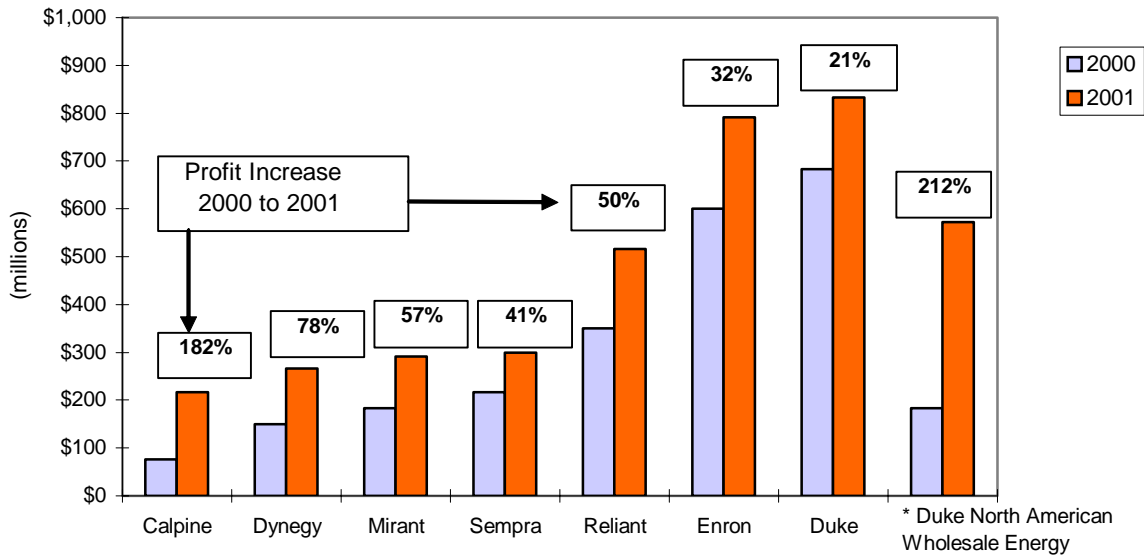
The effect of market manipulation was an artificial scarcity of power created by power generators to drive up prices and earn large profits. The potential for abuse of market power by generators increased significantly during periods when supply fell short of demand.²² Some observers have alleged that the repeated rounds of bidding under the market structure provided generators with scope to “game” the system by adjusting their bidding strategies to their advantage merely by observing each others bidding behavior without collusion in the accepted legal sense. This system enabled some market participants to realize high profits, as shown in Table 2 and Figure 5. Figure 5 below illustrates the degree to which this industry benefited from California’s crisis. During a period pegged by economists as the early part of a recession—U.S. corporate profits were down 12% in the first six months of 2001 compared to the same period in 2000—major energy companies, availing themselves of opportunities arising from California’s deregulation scheme, recorded unprecedented profits (FTCR, 2002).

Table 2 Increased Profits for Major California Power Suppliers in 2000

Power Suppliers	1999 (million \$)	2000 (million \$)	Increase (%)
Williams Companies	221	832	276
Calpine Corporation	95	323	240
Dynegy	146	452	210
AES Corporation	228	657	188
Arizona Public Service	127	307	141
Reliant Energy	528	819	55
Enron Corporation	893	1,266	42
Duke Enegy	1,507	1,776	18
Southern Company	1,276	1,313	3
Total	5,022	7,747	54

Source: Published company financial disclosure forms analyzed by Public Citizen, cited from <http://bernie.house.gov/pc/briefs/energysum.pdf>.

²² CAISO faces heavy demands on coordination to prevent arbitrage by market participants that led to inefficient dispatch of generating plants and higher prices than predicted under models of these competitive markets.



Source: Company SEC Filings and Company Press Release cited at FTCR (2002)

Figure 5 Increased Profits for Major California Power Suppliers (2002 Jan-Jun)

3.2.8 Significant Utility Influence

California’s energy crisis has mostly been ascribed to market design flaws, but the crisis can be described as “a political crisis of leadership and a corporate crisis of greed” (FTCR, 2002: 23). Its market design supported by the state’s deregulation law was influenced by a political compromise reached by various stakeholder groups including California’s three largest IOUs.²³ Their political committees spent \$69 millions (Table 3) on politics and lobbying between 1994 and 2000, with the majority of the total directed toward creating and retaining the law (Dunbar et al, 2001). An examination of political spending by the major utilities in California found that the Big Three– Pacific Gas & Electric Corp., Edison International and Sempra Energy– spent \$51.6 million toward political activities since 1994. The majority of that, \$39 million, was spent in 1998 in an all-out effort to defeat Proposition 9, a statewide referendum that would have overturned parts of the 1996 deregulation law. Proposition 9 was sponsored by the consumer groups to block bailout of utilities’ bad debts under deregulation law.²⁴

²³ The frozen rate was also designed to help utilities. The rate freeze kept California rates at pre-deregulation levels that were 40% above the national average. The difference between the frozen rate and the actual cost of electricity was pocketed by the state’s three utilities in order to pay off previous debts– largely from cost overruns on nuclear plant construction in the 1970s– that would otherwise render the electricity sold by California’s three utilities uncompetitive in a deregulated environment.

²⁴ Despite the millions spent by the utilities to ensure passage of a favorable deregulation bill, the three electric companies have lost billions to price-gouging wholesalers in a dysfunctional energy market they could not have anticipated.

**Table 3 Three Utilities' Expenditures to Support Passage of the
California Deregulation Law**

Utility	Contributions and Direct Expenditures	Lobbying	Total
Edison International	\$24,040,814	\$7,934,097	\$31,974,911
PG&E Corp.	\$22,428,693	\$5,456,300	\$27,884,993
Sempra Energy	\$5,123,005	\$4,023,799	\$9,146,804
Totals	\$51,592,512	\$17,414,196	\$69,006,708

Source: California Secretary of State

3.2.9 Market Governance

California's restructured electricity market ended up being designed in a highly politicized process (Joskow, 2001). The large size and politicization of the boards of CAISO and CALPX, through quotas of stakeholders each representing their own interests, hampered attempts to focus on getting the market to work. The governance arrangements for CALPX gave to some parties the voting power to block changes to market rules, which was done out of concern about putting market power in the hands of the UDCs. This led to the prohibition of trading on forward markets by the UDCs. Likewise, it is alleged that generators had too much power in CAISO, which they have used to block proposals to force them to schedule their entire output in the day-ahead market. In late 2000, FERC ordered the replacement of CAISO's stakeholder board by a non-stakeholder board.

4. Overview of Electricity Restructuring Model of PJM

PJM (Pennsylvania-New Jersey-Maryland Interconnection) has long been regarded as the prototypical power pool. It operates the largest wholesale electric market in the world. Its successful operation has been drawing attention especially in contrast with the failure in California.

4.1 Background

PJM has evolved as a power pool over 70 years. PJM's existence dates from 1927, when three utilities— PSE&G, PECO and PP&L— became signatories to the first power pool agreement, the PA-NJ Agreement. The PA-NJ pool continued for almost 30 years until it expanded to its present configuration as PJM in 1956. On January 1, 1998, PJM became the first fully functional ISO (Independent System Operator) in the U.S. and remains as the only ISO currently with this status in the U.S. PJM was conditionally approved as an RTO (Regional Transmission Organization) by FERC in 2001.

In 2005, the PJM market includes all or part of 13 states and 1 district (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and District of Columbia). This service area has a peak demand of about 131,330 MW. PJM serves approximately 51 million people in its control area. The company dispatches 163,806 MW of generating capacity over 56,070 miles of transmission lines. PJM has more than 350 market participants (PJM website, accessed in May 2005).

4.2 Market Model of PJM

4.2.1 Structural Features

The organizational entity of PJM - PJM Interconnection, LLC (limited liability company)²⁵ - is a non-profit entity that is independent of market participants. Its duties include: 1) central forecasting, scheduling, and coordination of the operation of generating units, bilateral transactions, and the spot energy market to meet load requirements; 2) monitoring, evaluating and coordinating PJM's transmission lines to maintain system reliability and security; 3) providing opportunities for transmission reservations through the PJM OASIS (open-access same-time information system)²⁶; 4) coordinating planning of the interconnected bulk power transmission system; 5) providing accounting, billing, and settlement services; and 6) facilitating the PJM Interchange Energy Market (PJM IEM) (NARUC).

²⁵ PJM Interconnection, LLC evolved from PJM Interconnection Association, an incorporated association on March 31, 1997 to function as an ISO.

²⁶ PJM OASIS is a web-based communications system to facilitate the timely exchange of system information and prices between transmission system operators and market participants. OASIS systems were required by FERC in Order 889.

Unlike the California model which consists of three institutions, (namely, an ISO, a PX, and SCs) PJM incorporates all functions into a single institution. PJM Interconnection administers all the day-ahead scheduling in the region. The Office of Interconnection (OI) of PJM Interconnection administers the PJM Interchange Energy Market (PJM IEM²⁷). The PJM Interchange Energy Market is a regional competitive spot market for wholesale electric energy and related services.

4.2.2 Governance and Management

Governance issues have shaped PJM's development and operations from its inception as an ISO. PJM's governance adheres to FERC's cardinal principle that an ISO's decision-making process must be independent of control by any market participant or class of participants. To achieve independence, PJM relies on a two-tiered structure that includes a fully independent non-stakeholder Board of Governors (the PJM Board) and a sectoral members committee to provide advisory support (Lambert, 2001: 201).

The PJM Board, whose express responsibility is to maintain reliability, create robust and competitive markets, and prevent undue influence by any member or group of members, manages PJM. The PJM Board is also charged with responsibility for supervising all matters pertaining to PJM and its operations. The PJM Board members must neither represent nor be affiliated with any particular industry sectors nor have any affiliation with any of the parties to the PJM Operating Agreement. The Members Committee elects Board members from a slate of candidates prepared by an independent consultant, not by the PJM members.

PJM's governance reflects a structural compromise to accommodate the transmission owners' initial desire to preserve residual oversight and management's need to operate independently. PJM's two-tiered governance model, coupled with member participation in decision-making, provides a forum for debate and participation. When PJM's business rules require adaptation to market conditions, change occurs collaboratively. In terms of financial independence, PJM has exclusive and independent control over recovery of its own costs through the PJM tariff and as a result is financially self-sufficient. Tariff-based cost recovery has permitted PJM to acquire, from the transmission owners, ownership of information technology and other capital assets previously used by it, and essential to its functions as an ISO (Lambert, 2001: 211).

ISOs such as PJM can in principle implement market monitoring to acquire detailed market information, intervene, if necessary, to prevent market power abuse, and even employ sanctions to prevent strategic withholding of capacity and use of transmission constraints to exclude competitors. PJM has established a market monitoring unit (MMU) within PJM to monitor and report on the operation of the PJM market. The MMU's responsibilities include matters relating to transmission congestion

²⁷ It is sometimes also called PJM PX.

pricing, exercise of market power, structural problems in the PJM market, design flaws in the operation rules, etc (Lambert, 2001: 213-215).

4.2.3 Market Pricing Rules

PJM members may trade electricity in the wholesale energy market, which operates on a day-ahead basis. On a day-ahead basis, PJM participants can either: (1) submit bids to the ISO and be centrally dispatched; or (2) opt out of centralized dispatch by submitting bilateral schedules, an option referred to as self-scheduling. In the case of central dispatch, participants submit offers to sell and bids to purchase electricity for the following day. The day-ahead market calculates hourly clearing prices for each hour of the next operating day. Prices are based on generation offers and demand bids submitted to PJM, which ranks offers and bids, from least to most expensive, based on total production costs. The matching of bids and offers establishes a clearing price for each hour of the next day. As the demand for electricity shifts up and down throughout the day, PJM keeps supply and demand in balance by calling on or off or giving instructions to adjust generation units or transactions. The real-time market calculates hourly clearing prices based on actual system operations dispatch (Lambert, 2001: 103).

Locational marginal pricing

On the basis of voluntary price and quantity bids received, PJM also determines market-clearing prices at each location or node on the grid, i.e., locational marginal prices (LMP) based on the marginal cost of serving the last increment of load at each location. Market-clearing prices are paid to all suppliers participating in the economic dispatch, while differences in locational prices between the point of receipt and the point of delivery are used to price transmission between those points and account for congestion (Lambert, 2001: 104). LMP is also used to procure and price ancillary services, settle point-to-point FTRs (fixed transmission rights) allocated and/or auctioned, and calculate charges or credits for diverse PJM market services including operating reserves, emergency energy.

LMP recognizes that transmission is economically equivalent to selling power at the point of receipt and buying it at the point of delivery. It allows all market participants to buy energy and transmission services at bid-based market prices. It therefore provides buyers and sellers with marginal incentives in the short-term market by ensuring that all transmission and energy transactions coordinated by PJM are priced equal to marginal cost. LMP produces efficient short-run decisions for electricity consumption and transmission use while providing a market-based method to signal efficient long-run grid expansion needs.

In addition, LMP provides both prospective generators and loads with efficient locational incentives. By pricing congestion directly, LMP also avoids the need to sweep congestion costs over a zone into a general uplift to permit recovery, a feature of the California market that complicated determination of market-clearing prices and distorted locational incentives. (Lambert 111-112)

Fixed transmission rights

Under the PJM tariff, PJM administers a system of firm transmission reservations, allowing each load-serving entity (LSE) to reserve sufficient firm transmission for its loads. In connection with firm transmission reservations, users receive fixed transmission rights (FTRs) entitling the holder to compensation for congestion-related charges that arise when PJM is required to re-dispatch generators out of merit in order to relieve congestion (Lambert, 2001: 105). FTRs are tradable price hedges that offset congestion-related transmission charges.

Trading in capacity rights

PJM's reliability committee periodically forecasts capacity needs for the PJM control area, both to serve loads and to act as capacity reserves. In so doing, the reliability committee allocates to each member that serves load in the PJM control area a portion of the aggregate capacity requirement. If a member is deficient, it must compensate, at a fixed deficiency charge, members that have excess capacity. To mediate between members in deficit and in surplus, PJM has established PJM capacity credit markets as auction markets in which certain LSEs offer to sell, and other LSEs bid to buy, entitlements (credits) to use generation capacity to meet their obligations (Lambert, 2001: 124). The reserve requirement of members has no direct parallel in the California model (although capacity credit markets are shared by the two models).

Two-settlement system

The PJM market operates under a two-settlement system that applies to day-ahead and real-time balancing markets respectively. In the day-ahead market, prices are determined based on the bids and offers and transmission schedules submitted by participants. The day-ahead market enables participants to purchase and sell energy at binding day-ahead prices. It also allows transmission customers to schedule bilateral transactions at binding day-ahead congestion charges based on LMP methodology. The balancing market, on the other hand, is a real-time energy market in which hourly clearing prices are determined by actual hourly quantity deviations from the day-ahead scheduled quantities and real time prices. LSEs or generators pay or are paid the balancing prices for the amount of electricity that exceeded or fell short of the day-ahead scheduled amount.

Generators that have capacity resources must participate in the day-ahead and balancing market unless they are self-scheduled or unavailable due to outage. This obligation of participation reduced significantly the possibility of market manipulation by market participants in PJM, unlike the California case. If an available capacity resource is not selected in the day-ahead scheduling because its offer price is higher than that of other generators, it may alter its bid for use in the balancing market. Otherwise its original bid in the day-ahead market remains in effect.

The day-ahead market thus provides financial incentives for generators, retailers, and transmission customers to submit day-ahead schedules that match their actual expectations for the operating day. It also provides the opportunity to obtain increased

price certainty. The balancing market provides financial incentives for generators to follow real-time economic dispatch instructions issued by PJM (Lambert, 2001: 130-134).

4.2.4 Securing System Reliability

PJM is responsible for the short-term reliability of the grid. PJM coordinates and operates its transmission system to this end. PJM quantifies and posts transfer capability so that transmission customers can figure out what can feasibly be transferred. To prevent over-commitment and assure system security, PJM preserves a portion of overall transmission network capability to accommodate changes in transmission capability caused by maintenance outages, higher than expected customer loads, etc. PJM evaluates transmission service requests to determine system impact and approves or denies the request accordingly.

Reliability assurance agreements (RAAs) signed by members and approved by FERC through adequate modifications requires transmission owners and other load-serving entities to satisfy capacity needs with sufficient reserve margins. PJM routinely prepares a regional transmission expansion plan (RTEP) in accordance with reliability criteria. The PJM Reliability Committee oversees capacity resource planning. PJM's planning and expansion process encourages market-driven operating and investment actions for preventing and relieving congestion. Information on constraints and congestion is available to market participants. Generators can react appropriately to congestion-determined price signals in determining where to site new generation or increase existing generator capacity (Lambert, 2001: 162).

As retail restructuring commenced in 1998, PJM created daily and monthly capacity markets to implement retail choice. As a result, the ability of load-serving entities to meet their annual load obligations in a daily market and the corresponding ability of generators to make a daily decision about whether to sell their capacity to PJM or sell it elsewhere created incentives that diminished the reliability of the PJM system. To address this problem, PJM modified its rules so that all load-serving entities are required to meet their obligations to serve load on a long-term basis, instead of a daily basis (Lambert, 2001: 166-167). Again, this constitutes a key difference between the PJM and California models.

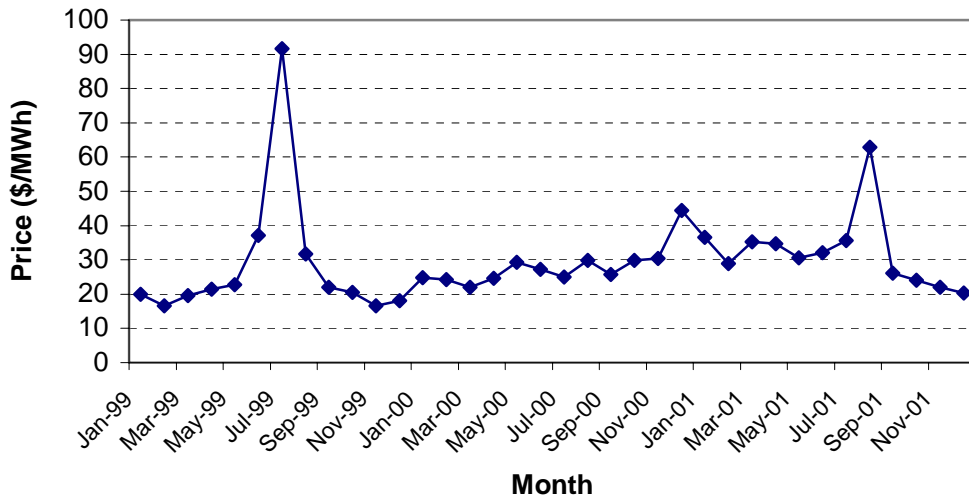
To extend its regional scope, PJM has recently entered into a comprehensive affiliation with the Allegheny Power System (APS), which has transferred control of its transmission facilities to PJM, allowing PJM seamlessly to extend its energy market and congestion management across all regions served by both entities (Lambert, 2001: 168). PJM West, the transmission organization that includes APS, began its operation in 2002 and substantially expanded the scope of PJM's existing regional market, planning process, and system operations. PJM has also been actively involved in interregional cooperation among ISOs in the eastern interconnection, especially ISO New England, the New York ISO, and Ontario's eastern interconnection. The expansion of regional scope and cooperation with adjacent ISOs provides PJM with important means for enhancing system reliability.

For securing long-term reliability, PJM forecasts electricity demand in a span of more than two years, establishes the reserve requirement for the control area, and determines the overall generating capacity requirement with respect to each load-serving entity. Each load-serving entity must submit its plans for providing its share of the overall requirement through installation of new capacity and purchases of capacity from non-load-serving entities and load-serving entities with excess capacity (Lambert, 2001 175-176).

4.3 Market Performance

4.3.1 Wholesale Market Price

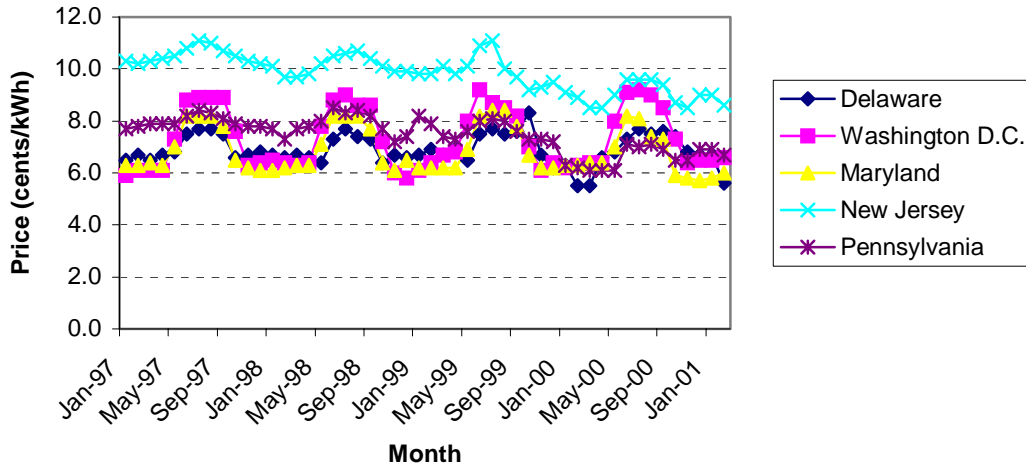
The wholesale market price for electricity in the PJM control area has been relatively stable since the transformation of PJM to an ISO in 1997 (see figure 6). It repeated ups and downs around the price range of \$20-\$40. Two exceptionally high prices were recorded during the summer season, in July 1999 and August 2001, respectively. The price hike in the summer of 1999 was due to the unanticipated shutdown of a nuclear generator in the region. But the amount of price hike in PJM (\$90/MWh at most) was much less than what was experienced in California (\$354/MWh). The price showed a general trend of a slight increase until the summer of 2001. It dropped again as fall and winter approached.



Source: PJM (www.pjm.org)
Figure 6. PJM Monthly Average LMP

4.3.2 Retail Market Price

Figure 7 shows retail market price trends for electricity in four states and the District of Columbia in (all are in the PJM area) during 1997 to 2001. Retail market prices in this area were relatively constant during the period of the California crisis (allowing for routine seasonal ups and downs, such as low prices during the winter and higher prices during the summer). The prices mostly ranged from 6 to 8 cents per kWh. The retail price of New Jersey, which was the highest in the region at that time, showed a downward trend throughout the period of the California crisis.



Source: Energy Information Administration

Figure 7. Retail Price Trend in PJM Area

5. Lessons from the Comparison of the Electricity Restructuring Models of California and PJM: Three Key Post-Crisis Issues

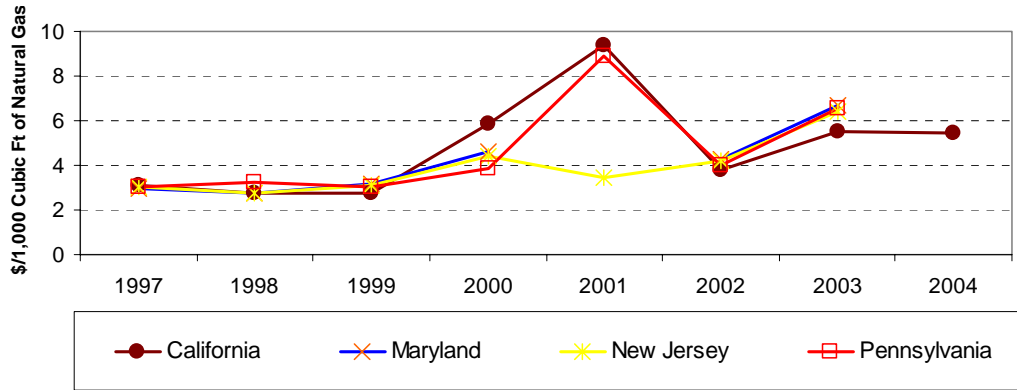
As shown above, the restructuring models adopted by California and PJM were quite different. While several comparisons have already been made, this section provides an analysis of three key issues that have surfaced in the wake of the California crisis and the 2003 Northeast blackout, which have special significance for policy design. The three key post-crisis issues are: wholesale electricity price volatility; the challenge of demand-supply imbalances; and the problem of outage threats. Through these key issues, it is possible to consider why the PJM model proved to be more reliable than the CAISO-CALPX model during the California power crisis period, and why the PJM Interconnection was able to prevent the cascading of the 2003 Northeast blackout into its control region.

5.1 Price Volatility

One of the most important differences in policy design between California and PJM is the degree to which the respective electricity systems depend upon spot markets to meet their needs. Almost all wholesale electricity transactions in California were completed through spot markets because all California IOUs were required to bid their generation and loads into the PX for the first four years of the California policy experiment. In PJM, by contrast, participants had two options: bilateral contracting or bidding into the central dispatch system. The portion of electricity transactions made through the spot market in the PJM control region was only 28% as of 2001, whereas the share of transactions reached approximately 87% in California.

In economic theory, a centralized market system like CALPX has an advantage in optimizing power plant dispatches compared to a system more dependent on bilateral contracts. However, when supply is tight, a centralized system is more vulnerable to market manipulation because a marginal bid determines the price that all bidders are paid at a given hour. And there is the further problem that electricity is not an ordinary commodity and economic theories created to explain commodity markets are not well-suited to explain likely behavior in a restructured electricity market.

This issue can be illustrated by comparing natural gas prices to power plant customers – often cited as a key factor in the electricity price volatility experienced in California – in the two jurisdictions and average wholesale market prices for electricity in the two markets. The natural gas sold to electric power consumers is presented in Figure 8 below. While the price of natural gas in California and Pennsylvania, for example, increased by more than 50% during 2000-2001, the CALPX average wholesale electricity price was three to five times higher than PJM's, a difference not easily explained as the result of 'optimal' market dispatch.



Source: EIA, US Natural Gas Price.

Figure 8. Annual Natural Gas Selling Prices to Electric Power Customers in California and PJM: 1997-2004

5.2 Demand-Supply Imbalance

5.2.1 Capacity Obligations

As a mechanism to ensure system reliability, capacity obligation is a key policy feature of the PJM electricity market model. PJM requires all Load Serving Entities (LSEs) to install or purchase capacity resources to cover their peak loads *plus* a reserve margin (Bowring and Gramlich, 2000). PJM allocates capacity obligations (120% of the peak loads) to all LSEs based on the previous year’s peak load and operates capacity credit markets where LSEs can sell and purchase credits needed to meet their obligations.

Under its policy design, there was no equivalent mechanism in California. Instead, the California ISO was in charge of securing enough capacity resources using its ancillary service market. Therefore, energy marketers in California could stay in business without ever owning any generation assets or having any bilateral contract for capacity resources. While generators in the PJM area can recover their fixed costs partially through capacity credit contracts, those operating in California did not receive separate capacity payments and therefore had to recover all of their costs from spot and ancillary service market bids.

In order to shore up supply reliability, including the maintenance of adequate reserve margins, the California Energy Commission in the post-crisis period has recommended developing a capacity market, which would provide flexibility for both utilities and generators in complying with the state’s resource adequacy rules (CEC, 2004).

5.2.2 Diversification of Resources

Following the unprecedented energy crisis in 2000-01, California suspended operations of its electricity spot market and re-introduced in 2003 an integrated resource planning strategy by adopting an “Energy Action Plan” (EAP) model as its long-term

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energy strategy. The goal of the Energy Action Plan is to “ensure that adequate, reliable and reasonably-priced electrical power and natural gas supplies...are achieved and provided through policies, strategies and actions that are cost effective and environmentally sound for California’s consumers and taxpayers” (State of California, 2003). In order to meet these goals, the state has focused on six actions which consist of planning for the availability and use of combinations of demand and supply options as follows:

First priority is placed on energy conservation and efficiency measures. It includes diverse incentives and pricing systems to incentivize reductions in electricity demand. As well, improved energy efficiency standards for buildings and air conditioners are mandated. According to the 2004 Integrated Energy Policy Report, energy efficiency and demand response programs reduced state electricity demand by approximately 6,000 MW, more than 10 % of peak demand in the 18 months after closure of CALPX (CEC, 2004). As a result, California has not experienced supply-demand balances that were seen in the 1998-2001 period.

Second, EAP also emphasizes the importance of renewable generation. In September 2002, Senate Bill (SB 1078) that created California’s renewable portfolio standard was signed. This standard requires the state’s three largest IOUs to increase total renewable energy sales by a minimum 1% annually beginning in 2003 until they reach 20% by 2017. Such significant progress has been made in achieving this target at cost-competitive prices for renewables that the state is now actively considering an amendment to its RPS that will accelerate achievement of the original 20% target by 2010. To meet the new target, investor-owned utilities will need to add a net 600 MW of new renewable generation sources per year by 2010. Because renewables are often the easiest power options to site, can receive expedited environmental approvals, and require short construction and start-up times to bring online, this supply strategy has created a buffer in the state that now protects it against unexpected losses of plants due to maintenance problems. Further, renewable sources of electricity generation have also been shown to provide an important hedge against natural gas spikes (see Bolinger et al., 2004; Roschelle & Steinhurst, 2004; and Biewald et al., 2003)

Third, EAP highlights that the state needs to ensure reliable and affordable electricity generation. To this end, the Energy Action Plan recommends that 1,500 – 2000 MW of new generation is needed in the coming decade and calls for the requirement of 15 to 18% reserve margins.

Fourth, EAP recommends that California upgrade and expand its electricity transmission and distribution infrastructure.

Fifth, distributed generation is also acknowledged as a key component of California’s energy system because it represents local resources that can contribute to system reliability without compromising environmental quality (see CEEP, 2005 for a detailed analysis of the utility benefits of distributed resources).

Finally, EAP requires reliable supply and reasonably priced natural gas because EAP concludes that volatile prices of natural gas contributed significantly to the California energy crisis in 2000-2001. As the natural gas spot market in California is believed to still be vulnerable to market manipulation and abnormal imbalances, EAP recommends vigilant monitoring of the market to identify any exercise of market power and manipulation. Regulatory agencies were encouraged to investigate possible market manipulation in the natural gas spot market as well as the electricity spot market in 2000-2001. In September 2002, El Paso Natural Gas Company was found guilty of illegally withholding natural gas from the state in order to drive up prices. In March 2003, the company agreed to a \$1.7 billion settlement with the State of California, and implicated Sempra Energy—parent company of Southern California Gas Company and San Diego Gas and Electric—as a co-conspirator (Timney, 2004).

In terms of energy efficiency measures and renewable energy, PJM has not been as aggressive as California. However, many states in its jurisdiction, including Delaware, Maryland, New Jersey and Pennsylvania²⁸ have enacted RPS laws recently as an effort to diversify their energy resources. In 2002, PJM initiated a demand response program to provide opportunities and incentives for customers to curtail their load during peak periods. Program participants are compensated for reducing their loads during peak times based on day-ahead and real-time locational marginal prices (LMPs) for transmission service during the interval of reduction. It is notable that PJM's demand response program provides a more attractive way for LSEs to meet their capacity obligations than conventional supply additions. LSEs have two ways to obtain the capacity credits: supply options and demand options. As mentioned previously, if LSEs are to meet their capacity obligations through supply increases, they are required to acquire 120% generation capacity based on previous year's peak load, which means that LSEs could get only 0.83 credits for each additional supply unit. On the other hand, if LSEs are committed to demand side load management, they get full credit for the unit reduction of load during peak periods.

5.3 Outage Threats

On August 14, 2003 at approximately 4: 10 pm EST, a major power outage took place in the Northeastern United States and Canada. A loss of transmission lines in Ohio triggered the cascading failures of other transmission lines and led to major voltage

²⁸ In November, 2004, the Pennsylvania Legislature approved the Alternative Energy Portfolio Standard Act (SB 1030) that requires 18 percent of the electricity sold in Pennsylvania to come from renewable and advanced energy sources within 15 years (Penn Future, Accessed on 20 November 2004). In May, 2004, Maryland enacted an RPS that requires 7.5% of retail electricity sales to be delivered from eligible renewable sources. In 2003, New Jersey set a 6.5% of RPS target by 2008. (The original RPS was enacted in 2001 but the 2003 amendment doubled the Tier I resources, which includes wind and solar generation in 2003, and a specific photovoltaics 'carve-out' was added in which a minimum amount of PV installed capacity must be realized). In June 2005, Delaware's RPS passed the General Assembly and has been signed into law by the Governor. CEEP played a central role in researching RPS legislation for the State and in writing the approved bill. The Delaware bill requires 10% of retail electricity sales to be provided from renewables by 2019.

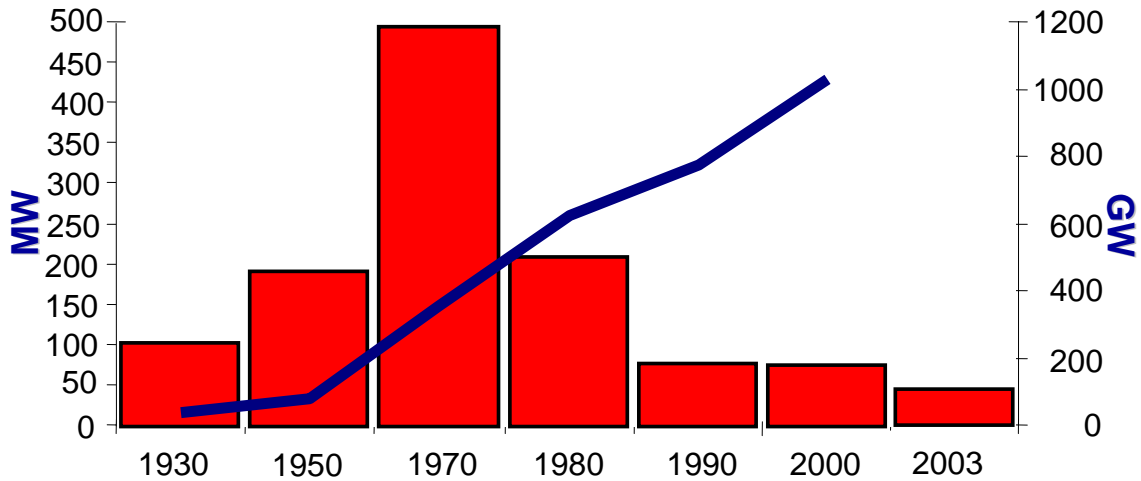
disruptions. The series of failures of transmission lines and corresponding voltage spikes resulted in several generating plants abruptly being removed from the grid. More than 60,000 MW of capacity was out of service during the blackout, affecting 50 million people in nine states in the US and one province in Canada in just 5 minutes. At least 265 power plants with more than 508 individual generating units shut down during the blackout (U.S.-Canada Power System Outage Task Force, 2004). Among the disabled generating plants were ten nuclear plants—7 US and 3 Canadian—totaling 19 units.

The area affected of the blackout included most of the Eastern Interconnection, which includes New York state (encompassing New York City), northern New Jersey, northern Pennsylvania, northern Ohio, eastern Michigan, parts of New England and eastern Canada (including Montreal and Toronto). However, the PJM area, which belongs to the Eastern Interconnection, remained intact and was not affected by the sequence of failures. One of the reasons is that PJM was able to isolate its jurisdiction from voltage surges. The automatic relays which monitor voltage and current in the grid in these areas acted properly when abnormal conditions developed. PJM is noted for having state-of-the-art automatic relays installed throughout much of its operations. In addition, there was sufficient generation capacity in the jurisdiction to stabilize load demand and supply after separation from the Eastern Interconnection. Prompt coordination of transmission and generation was key to surviving this abnormal situation. PJM has extensive in operating regional transmission lines with close coordination with utilities and generators. PJM has maintained a strong market oversight capacity and continues many of the planning and monitoring activities it operated before market competition was introduced. PJM also exercises significant power over transmission construction planning.

The experience of the 2003 blackout shows how large power plants connected to the grid can be vulnerable to grid disturbance. In order to protect equipment from unstable conditions in the transmission system, several large nuclear power plants were shut down or disconnected, eventually contributing to the speed and extent of the blackout. Moreover, once large generation power plants were shut down, re-energization procedures to restart them took several days depending on the type of plant and grid conditions. Because nuclear power plants have no black-start capability, off-site power supply must return to normal before equipment such as reactor coolant pumps and circulating water pumps can be restarted. As a result, nuclear power plants contributed to the 72-hour delay in returning electricity to residential customers in the blackout-affected area.

The potential and inherent instability of the existing bulk power delivery system requires rethinking of the current power system. Figure 9 shows the trend in overall power generation capacity and average size of power plants in the US. While total generation capacity continues to increase, a noticeable decline in average sizes of power plants has occurred over the last twenty years, with 100 MW being the average size currently. These relatively small-size generation technologies (including gas turbines, combined cycle plants, and renewable energy systems, so called distributed resources),

can decongest transmission and distribution systems resulting in enhanced system reliability (CEEP 2005).



Sources: T. R. Casten (1995) *The Energy Daily* (September 7); Hirsh (1999): 274; and *EIA Electric Power Annual* (1981, 1990, 2000, 2003)

Figure 9 US Generation Capacity and Average Plant Size: 1930-2003

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