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Paul L. Joskow

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ABSTRACT

This paper discusses the political, regulatory and economic factors that led to California's electricity crisis in 2000 and 2001. It begins with a discussion of the origins of California's electricity restructuring and competition programs. It then discusses the structure of the wholesale and retail markets and associated transition institutions created in 1996-98 and the performance of these institutions during their first two years of operation. The discussion of the electricity crisis is then conveniently broken down into three phases: (a) May 2000 through September 2000, (b) October 2000 through December 2000, January 2001 to the June 2001. Each phase is discussed in turn. The paper concludes with a discussion of lessons about electricity market liberalization gained from the recent experience in California.

Paul L. Joskow
Department of Economics
E52-280B
MIT
Cambridge, MA 02142
and NBER
pjoskow@mit.edu

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Paul L. Joskow[1]
MIT
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INTRODUCTION

The collapse of California's electricity restructuring and competition program has attracted attention around the world. Prices in California's competitive wholesale electricity market increased by 500% between the second half of 1999 and the second half of 2000. For the first four months of 2001, wholesale spot prices averaged over $300/Mwh, ten times what they were is 1998 and 1999. Some customers have been required involuntarily to curtail electricity consumption in response to supply shortages. While wholesale prices rose dramatically, retail prices were fixed until early in 2001.[2] As a result, California's two largest utilities --- Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) --- were paying far more for wholesale power than they were able to resell it for at retail. Both effectively became insolvent in January 2001 and stopped paying their bills for power and certain other financial obligations. PG&E declared bankruptcy on April 6, 2001 and its reorganization is now before a federal bankruptcy court.

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[1] [1]Elizabeth and James Killian Professor of Economics and Management and Director of the MIT Center for Energy and Environmental Policy Research (CEEPR). I am grateful for financial support from the CEEPR and for detailed comments from Denny Ellerman. I have benefited from discussions with Severin Borenstein, Frank Wolak, Ed Kahn, and Bill Hogan. Erich Muehlegger provided excellent research assistance.

[2] California has three major Investor-Owned Utilities (IOUs): Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E) and Southern California Edison (SCE). PG&E and SCE are about four times larger than SDG&E. SDG&E's retail prices were allowed to adjust to changes in wholesale market prices beginning in January 2000, but special state legislation subsequently capped its retail prices as well.

As utility credit problems became evident, unregulated suppliers of wholesale power began to stop selling power to them. For a short period of time, emergency orders issued by the U.S. Department of Energy (DOE) and federal courts required generators subject to federal jurisdiction to continue supplying until the mess could be sorted out. The State of California eventually stepped into the breach (through the California Department of Water Resources - CDWR) and used state funds to buy power from unregulated wholesale suppliers to avoid widespread blackouts. It spent roughly $8 billion doing so between January and May 2001 and has also negotiated long term contracts with suppliers stretching out as long as twenty years into the future. These contracts are reported to involve commitments of about $50 billion more. Retail price increases of 30 to 40% went into effect in June 2001 and retail prices are likely to remain high for many years to come as the long term contracts negotiated by the State are paid off. Although wholesale prices began to moderate significantly during June 2001, the future of California's experiment with electricity restructuring, wholesale and retail competition program remains murky at best.

This was certainly not what California planned would happen by reforming its electricity industry! And while many analysts predicted that there would be problems resulting from a variety of market design and regulatory decisions made during the new system's formation, nobody predicted that California's electricity restructuring and competition reforms would lead to such a huge mess. This paper discusses the political, regulatory and economic factors that led to California's electricity crisis. It begins with a discussion of the origins of California's electricity restructuring programs. It then discusses

the structure of the wholesale and retail markets and associated transition institutions created in 1996-98 and the performance of these institutions during their first two years of operation.[3] The discussion of the electricity crisis is then conveniently broken down into three phases: (a) May 2000 through September 2000, (b) October 2000 through December 2000, January 2001 to the June 2001. Each phase is discussed in turn. The paper concludes with a discussion of lessons about electricity market liberalization gained from the recent experience in California.

CALIFORNIA RESTRUCTURING PROGRAM: 1994 - 1999

For nearly a century, California's electricity industry was organized around three regulated private vertically integrated monopolies (IOUs) which owned and operated generation, transmission and distribution facilities to provide for the electricity needs of all consumers in their exclusive franchise areas: Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).[4] Their prices, costs, and service obligations were heavily regulated by the California Public Utilities Commission (CPUC), an independent state regulatory agency. While utilities in California owned and operated generating plants to supply a large fraction of their retail customers' needs, they also depended on purchasing significant amounts of power in the long-standing wholesale market from utilities in other

[3] A more detailed discussion of the pre-2000 period can be found in Joskow (2000).

[4] PG&E and SDG&E are also gas distribution companies. PG&E, SCE, and SDG&E account for about 75% of the electricity sold in the state. The rest is supplied by municipal utilities, irrigation districts, and public water agencies. The state's municipal utilities, irrigation districts and water agencies have not participated in the electricity restructuring and competition program.

Western states, Canada and Mexico.[5] (Together this region comprises a single synchronized electric power network that operates under the supervision of the Western System Coordinating Council or WSCC.) During the 1960s and 1970s, utilities in California built long transmission lines to gain access to power supplies in the Northwest and Southwest. While California was primarily an importer of power from these regions, it also sold power to them when it was economical to do so. For example, California purchased large quantities of energy from hydroelectric facilities in the Northwest during the Spring and Summer seasons and sold energy to the Northwest during off-peak periods in the Winter.[6]

Regulatory responsibilities for electricity supplied by private firms in the U.S. are split between individual state public utility commissions and the Federal Energy Regulatory Commission (FERC).[7] State commissions regulate retail prices and traditionally relied on the total costs of vertically integrated utilities providing service in a state to set retail prices. They also traditionally were responsible for oversight of utility planning and reviewing the reasonableness of their costs. In California, the California Public Utilities Commission (CPUC) regulates retail electricity prices and other terms

[5] The Western states of the U.S., British Columbia, Alberta and portions of Mexico are part of the same synchronized AC network --- the Western States Coordinating Council (WSCC), made up of about 35 control areas. California had 7 control areas prior to restructuring: The three IOUs, two municipal utilities, one irrigation district, and a small piece of an IOU operating primarily in Oregon in the northern corner of the state. Active wholesale electricity markets built around bilateral contracts between utilities have existed in the U.S. for several decades. However, as of 2000, California was the only Western state to restructure its electric power sector. Utilities in other Western states bought and sold power in the wholesale market, but their obligations to retail customers were largely covered by the generating plants that they owned and whose prices were regulated using traditional cost-of-service principles.

[6] California and the Southwest peak in the summer and the Northwest peaks in the winter. The Northwest has extensive hydroelectric resources. Cheap energy was typically available during the Spring and early summer in the Northeast as snow melted, dams filled and had to spill water.

[7] A more detailed discussion of the pre-reform structure and regulation of the U.S. electric power industry

and conditions of retail service. FERC is responsible for regulating prices and other terms and conditions of sales of power made by one utility to another ("wholesale" power transactions) and sales of unbundled transmission service required to support wholesale power transactions. As long as the industry was made up primarily of vertically integrated utilities that owned generation, transmission and distribution facilities to serve retail demand in their franchise areas, the vast bulk of utility revenues and costs were subject to state commission regulation. In those states, like California, where industry restructuring has separated and "unbundled" generation, transmission, distribution and retail supply, market sales of power made by previously integrated generating facilities and sales of the transmission service to support it become subject to FERC regulation.

FERC too traditionally regulated wholesale power and transmission prices based on cost of service principles. However, beginning in the late 1980s, FERC began to encourage the further development of competitive wholesale markets and began to grant wholesale power producers the authority to sell at "market-based rates" if they could show that they lacked market power and that the prices at which they sold power would reflect the interplay of supply and demand in well-functioning markets.[8]

In early 1993, the CPUC launched a comprehensive review of the structure and performance of California's electricity industry.[9] It was motivated primarily by pressure from industrial consumers to reduce electricity prices which were among the highest in

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can be found in Joskow (1989) and Joskow (2000).

[8] See Joskow (2000) for a discussion of these developments.

[9] The CPUC issued a report in 1993, generally called the "Yellow Book," committing itself to reforms. See Joskow (2000) for a discussion of the political economy of electricity restructuring in California and other states.

the U.S. and much higher than those in neighboring states in the West.[10] High electricity prices in turn were blamed on failures of the existing system of regulated vertically integrated monopolies: the high costs of nuclear power plant investments, expensive long-term contracts with independent power suppliers, excess generating capacity, costly and ineffective regulatory institutions. There was broad agreement that the existing industry structure and regulatory system needed to be reformed. The nature of the most desirable reforms was very controversial, however.

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."[11] 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. This vision for reform was heavily influenced by reforms implemented in Britain in 1990.

In early 1996, after two years of debate among interests groups about the proposed reforms and transition arrangements, the CPUC issued its long-awaited

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[10] Most of the other states with high retail electricity prices were in the Northeast. California is the only state in the West to adopt this type of radical restructuring program.

[11] *Proposed Policy Statement on Restructuring California's Electric Services Industry and Reforming Regulatory Policy*, April 20, 1994. Several of the then sitting Commissioners have also told me that their visit to England and Wales in early 1994 to study the competitive electricity system that had been created there in 1990 greatly influenced their decision to endeavor to create a similar system in California.

restructuring decision.[12] Later that same year, the California legislature passed a restructuring law (AB 1890) that largely followed the architecture delineated by the CPUC's restructuring order, but that also included a number of significant refinements. Taken together, the major provisions of AB 1890 and CPUC electricity sector restructuring regulations include:

1. Retail "customer choice" or retail wheeling: effective in 1998, all retail customers were given the ability to choose a competitive electricity service provider (ESP) to provide them with generation services. If they did not choose an ESP they could continue to receive "default service" from their local utility distribution company (UDC) at prices determined by the CPUC and the provisions of AB 1890. It was expected that most retail customers would gradually migrate to ESPs during the four-year transition period.

2. IOUs were required to provide open access to their transmission and distribution networks to competing generators, wholesale marketers, and ESPs at prices determined by FERC and the CPUC.

3. Each UDC's default service energy price, charged to customers who did not choose an ESP, was (effectively) set equal the wholesale *spot* market prices for power determined in the day-ahead and real-time markets (see below), adjusted for physical losses, plus avoidable billing and metering costs. This was the "price to beat" for ESPs.

4. Provisions were made for utilities to recover their stranded costs, which included incentives to divest generating assets and to renegotiate QF contracts. Stranded costs associated with most utility generating assets had to be recovered within a four-year transition period during which retail rates are generally frozen at their 1996 levels, with

[12] Decision 95-12-063 (December 20, 1995) as modified by Decision 96-01-009 (January 10, 1996).

the exceptions noted below. The assumption was that wholesale power prices would be significantly below the prevailing price of generation service reflected in regulate retail rates; after all, the primary motivation for the reforms was the prospect of consumers getting access to the "cheap power" expected to be available in wholesale markets. Nobody broached the possibility that wholesale prices could possibly be higher than the regulated price of generation service reflected in prevailing retail prices. The entire rationale for the reforms was that wholesale prices would be lower than the regulated retail price of generation service. And, of course if wholesale prices were higher that the regulated cost of generation service there would be no stranded costs to worry about! Accordingly, what were assumed to be huge stranded utility generation costs were to be recovered from the difference between the regulated retail prices in effect in 1996, the utility's actual distribution and transmission costs, and the wholesale spot market price of generation service for a period of up to four years. If stranded utility generation costs were recovered sooner than four years, then the rate freeze would end immediately and retail prices would "fall" to reflect prevailing wholesale market conditions.[13]

5. AB 1890 enabled utilities to "securitize" a fraction of their stranded costs by issuing bonds whose interest and amortization is guaranteed by the state to be paid out of stranded cost charges that utilities are authorized to include in their distribution charges. Essentially, these provisions made it possible for utilities to refinance a portion of their generating assets with 100% highly rated debt instruments, replacing the roughly 50/50

[13] Prior to 2000, the CPUC's primary concern was to see that the rate freeze would end as quickly as possible and went to great efforts to ensure that utilities did not extent the rate freeze beyond the time necessary to recover stranded costs. Note that the 4-year limit on stranded cost recovery applied only to utility generating assets. Stranded costs related to QF contracts could continue to be recovered after the rate freeze period ended through a non-bypassable distribution charge.

debt to equity ratio with which the generating assets had been financed and the associated financing costs reflected in the regulated prices upon which the rate freeze are based. Securitization was designed to reduce the utilities' cost of capital and income taxes associated with carrying stranded costs.

6. Residential and small commercial customers received an immediate 10% price decrease from then prevailing regulated prices, financed by the cost savings from securitization. (So, 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.)

7. Distribution and any remaining state-jurisdictional transmission charges were regulated using incentive regulation mechanisms, or what is now referred to in the U.S. regulatory arena as Performance Based Regulation (PBR).

8. The IOUs were directed to help to create two new non-profit transmission network operation and wholesale market institutions. The first is the California Independent System Operator (CAISO), that would operate the transmission networks owned by the three major California IOUs and would be responsible for running various energy balancing, ancillary service, and congestion management markets that I will discuss presently. The second is the California Power Exchange (CALPX), which would run day-ahead and hour-ahead hourly public wholesale markets for sales of energy. Both CAISO and CALPX are non-profit corporations with governing boards that include representatives of major interest groups as well as "public interest" members.

9. The two largest IOUs were ordered to divest at least half of their fossil generating capacity in California and strongly encouraged to divest all of their generating capacity to mitigate horizontal market power problems and to provide a simple valuation

of stranded costs. All three IOU's eventually divested all of their fossil-fueled generation in California. However, they retained their nuclear plants, their hydro-electric plants, and their existing long-term contracts.[14] The three IOUs were required to meet their default service obligations by purchasing all of their remaining customers' requirements in the day-ahead and real-time spot wholesale markets operated by the PX and ISO. Mechanically, the utilities sold power from their remaining generating assets (including long-term contracts) into these markets and then bought it back to meet their default service demand. They were effectively "short" the difference between default service demand and what they could supply from their remaining generating assets. Requests by the utilities to hedge their short position beginning in 1999 were either denied or so restricted by the CPUC that little forward purchasing took place before 2001. As I will discuss, despite earlier predictions, no more than 12% of retail demand migrated to ESPs. As a result, the three utilities had a default service demand that was much higher than expected and, after divestiture, their net short position was much larger than expected.

[14] In addition, SCE owns coal plants in Nevada and New Mexico and has entitlements to hydroelectric energy from Hoover Dam in Nevada. Altogether, the utilities retained about 18,000 Mw of firm power supply resources. In addition, their control areas were responsible for dispatching about another 6,000 Mw of generating capacity owned by municipal utilities whose demand is included in their control areas. The aggregate peak demand of the IOUs and municipal utilities within their control areas is about 45,000 Mw and the average hourly demand is about 27,000 Mw.

WHOLESALE MARKET INSTITUTIONS[15]

The process of designing the details of California's wholesale and retail market institutions was extremely contentious. Different interest groups presented different reform "models." The CPUC was itself divided about the appropriate wholesale market framework, with one group preferring a "Poolco" model very similar to that introduced in England and Wales in 1990 and another preferring a "bilateral contracts" model based very loosely on the structure of natural gas markets and the interactions between pipelines, producers, marketers, and industrial and local gas distribution system buyers. Ideological rhetoric played a bigger role than serious analysis or practical experience drawn from other countries. In the end, the ultimate design of the wholesale market institutions represented a series of compromises made by design committees including interest group representatives, drawing on bits and pieces of alternative models for market design, congestion management, transmission pricing, new generator interconnection rules, and locational market power mitigation. The process went from bad to worse in 1997 once the ISO and PX were constituted (on paper) and a Trustee and staff were appointed to push the process forward. Getting it done fast and in a way that pandered to the many interests involved become more important than getting it right. The end result was the most complicated set of wholesale electricity market institutions ever created on earth and with which there was no real-world experience.

[15] The discussion that follows reflects the structure of the market as it was originally designed and, more or less, operated until early 2001. On January 2001, the PX stopped operating and eventually filed for bankruptcy. Since then, there has been no public organized power exchange in California. Buyers and sellers rely either on bilateral contracts which are scheduled with the ISO, self-supply in the case of the portion of utility load that can be served from their remaining resources, or purchases from the ISO's real-time imbalance market.

California's restructuring program required the IOUs in California to create an Independent System Operator (CAISO) and a Power Exchange (PX) and to turn the operation of their transmission networks over to CAISO. The PX and CAISO in turn were required to operate public markets with transparent hourly market clearing prices for electric energy and operating reserves (ancillary services), and to manage congestion using market mechanisms. The institutional structure adopted by California is quite ambitious compared to the designs that characterize wholesale markets created earlier in England, Chile, and Argentina. It relies more on individual generator owners making decentralized unit commitment and dispatch decisions to supply energy and ancillary services and to manage congestion based on their own self-interests, and provides more bidding, dispatch and pricing flexibility than do most of the earlier organized electricity markets.[16]

The California ISO (CAISO): It will be useful to refer to Figure 1, which depicts the structure of the California wholesale electricity market institutions, to follow the rest of the discussion in this section. CAISO is the core institution that governs the operation of a large portion of the transmission system in California and the system's use as a platform for wholesale and retail market trading of electricity.[17] CAISO is a non-profit public benefit corporation organized under the laws of California. However, it is 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. CAISO is responsible for operating the transmission networks owned by the three major investor-

[16] In this regard it is closer to the New Electricity Trading Arrangements (NETA) introduced in England and Wales in 2001.

[17] LADWP, Pasadena, and the Imperial Irrigation District maintain their own control area, accounting for about 7,500 Mw of peak demand that is scheduled and dispatched separately from the CAISO. It was hoped that municipal transmission owners in California would also join CAISO, and that it would expand

owned utilities in California, is responsible for coordinating these operations with interconnected transmission systems in the Western System Coordinating Council (WSCC)[18] and operates a control center to do so.

The peak load served within the CAISO is about 45,000 Mw and there is roughly 44,000 Mw of generating capacity connected directly to its network.[19] The generating resources are a mix of gas, nuclear, hydroelectric, coal, and long-term contracts with QFs. Importantly, nearly 40% of this generating capacity is relatively old gas-fired steam and combustion turbine capacity. This capacity is generally at the top end of the supply stack and gas fired capacity was historically the "marginal" marginal supply source that balanced supply and demand about 80% of the time. All of this gas-fired capacity was divested by the IOUs to five independent generating companies in 1998 and 1999.[20] During peak periods, supply and demand must be balanced with imports or interruptible contracts with industrial customers (or rolling blackouts). CAISO has adopted protocols that allow (G) generators directly connected to the transmission facilities it operates, as well as generators that can move their power over neighboring transmission systems to points of

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to include transmission owners in neighboring states. This has not yet happened.

[18] The WSCC is a regional reliability council that covers all of the states (roughly) west of the Rocky Mountains, western Canada, and portions of northern Mexico. Significant imports of energy into California and (less significant) exports of energy from California occur continuously. The volume and direction of trade varies widely with changing demand patterns in the WSCC and the availability of supplies from generating facilities, especially hydroelectric supplies.

[19] This includes both the demand and resources of several municipal utilities that were previously integrated physically into SCE and PG&E's control area network as well as SCE's generating resources in Nevada, Arizona and New Mexico which are dynamically scheduled by the ISO.

[20] The companies buying this capacity were primarily affiliates of electric utilities with retail service areas in Texas, Georgia and North Carolina --- Southern, Duke, Reliant. A Texas-based gas marketing company (Dynegy) was also a purchaser of some of these assets. AES, and independent power producer, also purchased assets in Southern California. It subsequently entered into a tolling agreement with Williams (a energy marketer and pipeline company) and it is Williams that has been marketing the power produced from these facilities and apparently controls their dispatch.

interconnection with CAISO's network, to be scheduled to serve demand (or load- L) supplied over CAISO's network through intermediaries called Scheduling Coordinators (SC).

CAISO accepts hourly schedules from SCs on a day-ahead basis and an hour-ahead basis, and then manages the operation of the system in real time based on market information it receives from sellers and buyers and the physical constraints of the network. Demand and supply realized in real time can vary from day-ahead or hour-ahead schedules, and CAISO is responsible for balancing supply and demand in real time. To do so, it operates a real time energy balancing market into which generators can submit bids to supply more energy or to reduce the energy they have scheduled to supply to the network. CAISO also manages transmission congestion through its day-ahead scheduling process and in real time. To manage congestion economically, it relies on hourly adjustment bids and supplemental energy bids submitted by generators. When congestion arises, the marginal supply cost at different nodes on the network will vary (Joskow and Tirole (2000)). California has adopted a "zonal" congestion management system which allows separate market clearing energy and ancillary services prices to emerge in Northern and Southern California (separated by a transmission path called "path 15")[21] and at each point of interconnection between the CAISO's facilities and those of neighboring transmission operators.[22] SC's scheduling supplies from one zone to another must make congestion

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[21] In early 2000, CAISO created a third congestion zone (ZP 26) that lies between the original Northern and Southern zones.

[22] The Pennsylvania-New Jersey- Maryland (PJM) ISO and the New York ISO have implemented full nodal pricing systems. New York's wholesale market and congestion management system first became operational on November 17, 1999. The New England ISO also intends to implement a nodal pricing and congestion management system. These systems follow closely the nodal pricing models developed by Bill Hogan (1992,1993).

payments to the ISO during periods of congestion. These payments are equal to the difference in the clearing prices, based on adjustment bids, on either side of any congested interface times the quantity being scheduled across it. These payments are then rebated to the entities that hold firm transmission rights on the congested paths.[23]

CAISO is also responsible for purchasing various operating reserve services ("ancillary services") from generators -- frequency regulation (also called Automatic Generator Control or AGC), spinning reserves, non-spinning reserves, and replacement reserves -- to respond to unanticipated changes in demand or plant outages in order to maintain the short term reliability of the network. It operates day-ahead and hour-ahead markets for each of these reserve services for each hour of the day. These markets select generators that agree 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 the ISO to supply energy. Generators selected in these ancillary services auctions are paid a uniform hourly market-clearing reservation price to hold the capacity in reserve and are then paid for the energy they supply if they are subsequently called on by the ISO to supply energy.

Finally, the ISO is 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 over the facilities operated by CAISO.

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[23] CAISO ran its first Firm Transmission Rights (FTR) auction during the week of November, 1999.

The California Power Exchange (PX): California's restructuring program created a separate "voluntary" public market for trading energy for each hour of the day on a day-ahead and hour-ahead basis.[24] This organization is the California "Power Exchange" or PX. The PX is a non-profit corporation organized under the laws of California and is also an SC for purposes of interacting with CAISO. Pursuant to California's restructuring legislation (AB 1890, passed in 1996), the IOUs in California must place all of the day-ahead demand from their default service customers through the PX on an hourly basis. They must also bid all of the energy supplied from any generating units they continue to own or power supplied to them under pre-reform long term contracts into the PX as well. Other generators and other demand-serving entities (e.g. marketers, municipal utilities in California or utilities in other states) may voluntarily trade in the PX if they choose to do so.

The PX took the hourly day-ahead supply and demand bids and "stacked them up" 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. All buyers paid the uniform market clearing price and all sellers were paid this uniform market clearing price. The winning supply bidders in each hour then constituted the PX's preferred day ahead schedule submitted to the ISO. The PX is essentially a short-term forward market. Winning suppliers take on a financial obligation based on the market clearing price in each hour, but not a physical supply obligation. However, prices in the PX and the ISO's real time and ancillary services markets are linked by arbitrage

[24] The existence of a separate PX distinguishes the California structure from most other organized electricity markets. ISO-New England, PJM, and New York ISO operate both day-ahead energy and ancillary services markets. That is, there is no separate public PX in these regions.

opportunities. If the real time price is expected to be higher that the day-ahead price, suppliers will withdraw supplies from the day-ahead market and wait to bid them into the ISO's real time energy market and vice versa. Similarly, suppliers of ancillary services are effectively being paid to hold some capacity in reserve just in case they are needed by the ISO. The opportunity cost of holding this capacity in reserve is roughly equal to the difference between the expected day-ahead or real time price and the marginal cost of production.

Other Scheduling Coordinators (SC): A Scheduling Coordinator (SC) is any wholesale entity that has been licensed to schedule power on the CAISO network and agreed to abide by its operating rules and payment obligation. Non-utility generators and wholesale marketing intermediaries marketers may register as SCs with CAISO if they agree to abide by CAISO's terms and conditions for scheduling power on its network. They must adhere to the ISO's operating and payment rules and meet credit requirements. An SC can organize its own portfolio of supply resources and load obligations and schedule its portfolio for physical delivery with CAISO. SCs rely on bilateral financial contracts with buyers and sellers (or owned-generation) to assemble their portfolios and are then supposed to submit balanced schedules (supply schedule = demand schedule) for each hour to the CAISO. The prices SCs pay to generation suppliers or charge to buyers and the methods they use to manage congestion are internal to each SC and such information is not public. 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 have registered as SCs.

Entry of new generating capacity: 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. 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 obtaining all necessary siting permits to be a slow and frustrating process.

INITIAL ASSESSMENT OF WHOLESALE MARKET PERFORMANCE : 1998-1999

The new competitive wholesale and retail electricity markets began operating in April 1998. Several important software functionalities were not ready at the time the markets opened in April 1998, there was poor coordination between the PX and the ISO, and the limitations placed on the ISO'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. Flaws were identified in the congestion management system, with the contracts designed to mitigate local market power problems,[25] the protocols for planning and investment in transmission and the interconnection of new generating plants, the real time balancing markets, the ancillary services markets, under-

[25] The "local market power problem" in California is very similar to the "constrained-on plant" problem that emerged in the early years of the new electricity market arrangements in England and Wales. Office of Electricity Regulation (1992).

scheduling before real time operations, and other areas. These market design flaws increased the costs of ancillary services far above projections, led to scheduling and dispatch inefficiencies, slowed down investment in new power plants, increased the costs of managing congestion, increase spot market price volatility, and increased wholesale market prices generally.

In addition, there was evidence of episodic horizontal market power problems that emerged from time to time during very high-demand periods.[26] During low and moderate demand conditions, the energy markets appeared to be quite competitive, with day-ahead prices observed to be reasonably close to estimates of marginal cost. This was generally the case whether or not there is congestion observed on Path 15 or the ties with other systems.[27] When demand gets very high, however, it is clear that the market is clearing at prices far above the marginal cost of the most expensive generators in the region. Since there is virtually no real demand elasticity yet in these markets, a during peak periods most demand is satisfied with purchases in the spot markets, it is evident that as demand grows and supply gets very tight, generators realize that a small amount of capacity withholding, even with moderate levels of concentration, can lead to large price increases. All of the

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[26] The performance of California's electricity markets has been subject to extensive scrutiny because the institutional arrangements approved by FERC (wisely) included a requirement that the ISO create a Market Surveillance Committee (MSC) and that the PX create a Market Monitoring Committee (MMC). Both committees have independent members, primarily academic economists. They have issued several reports and produced several papers based, in part, on proprietary data available only to the PX and the ISO. CAISO MSC Report, October 1999, Borenstein, Bushnell and Wolak, July 1999, Bushnell and Wolak, July 1999. The performance assessments are reviewed in Joskow (2000).

[27] Historically, congestion on California's transmission network tends to occur in the North to South direction as a result of abundant suppliers of hydroelectric energy in the Northwest and Northern California in the Spring and early summer, when demand is relatively low. Congestion tends to occur in the South to North direction in the fall and winter at night when cheap energy from the Southwest is (effectively) being exported to the Northwest through California. The high priced periods in the summer of 1998 did not generally coincide with significant congestion. Demand was high everywhere in the WSCC, and there was little energy for export to California from the Northwest and Southwest.

studies that were conducted prior to the crisis found that during very high demand periods, unilateral behavior leads to prices that are significantly above competitive levels.[28] The ISO has had bid caps in effect on real time balancing energy since the markets began operating and imposed price caps on ancillary services markets in July 1998, when prices reached $10,000/Mw.[29] However, prior to Summer 2000, the effects of horizontal market power on prices was small and the supply and demand conditions when it emerged short-lived.

By 1999, a number of additional concerns began to emerge. The ISO began to express concerns about the slow pace of completion of new power plants, the rapid growth in demand and the rapid reduction in reserve margins. The unexpected spot market price volatility, the small number of retail customers who had shifted to ESPs (see below), and the slow progress on new power plant projects began to lead to concerns about California's heavy reliance on spot markets to meet retail demand.

When the California wholesale and retail market institutions were being created FERC gave considerable deference to California government officials and the outcomes of stakeholder negotiations, despite FERC staff's reservations about many of the details. As more and more problems began to emerge, FERC gradually began to reject some proposals forthcoming from California and to provide more "guidance" for resolving them. Within the first two years of operation, the ISO had filed about 30 major revisions to its protocols with the Federal Energy Regulatory Commission (FERC).[30] The PX had filed for

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[28] ISO Annual Report, Borenstein, Bushnell and Wolak (1999), CAISO MSC Report, October 1999.

[29] ISO Annual Report, Chapter 3

[30] California ISO Annual Report.

numerous changes in its operating protocols as well. FERC did allow the ISO to price caps on prices for energy and ancillary services in 1998 to respond to a variety of market imperfections. The level of these caps varied over time, but price caps were in effect until mid-December 2000. Responding to a never-ending series of problems and proposed fixes for them, in late 1999 FERC ordered the ISO to seek to identify and implement fundamental reforms rather than just piecemeal fixes to individual problems as they arose. This reform process was not completed prior to the more serious problems that began in May 2000.

Much has been made in the press about the alleged failure of California utilities to add new generating capacity for as much as 13 years. The facts are somewhat different. Beginning in the early 1980s, California aggressively implemented the provisions of the Public Utility Regulatory Policy Act (PURPA) passed by the U.S. Congress in 1978.[31] PURPA required utilities to purchase power from certain qualifying (QF) cogeneration and small power producers using renewable fuels. California wanted to encourage cogeneration and renewable energy and required utilities to purchase power produced from such facilities under long-term contracts with very high prices. Roughly 7,000 Mw of QF generating capacity began operating in California between the late 1980s and the early 1990s. So much QF capacity was completed that there was very significant excess capacity by the early 1990s. The high-priced QF contracts and the excess generating capacity helped to drive up regulated retail prices which passed these costs along to retail consumers. The excess capacity situation that existed when the discussions of restructuring began in 1993 was expected to last for another next decade.

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[31] See Joskow (1989) for a more extensive discussion.

After the QF projects came into service by the early 1990s, no new generating capacity was added in California and little new generating capacity was added *anywhere* in the Western United States for the rest of the decade. There are two primary reasons. First, there was excess capacity in the early 1990s that was expected to last for many years. Second, during the contentious discussion about electricity restructuring in California and other Western states during the second half of the decade, the rules under which new power plants would be built and their owners compensated were in flux. In California, utilities were already effectively precluded from building new power plants. It is not surprising that investors would not commit funds to build new plants until the new rules of the game were clear. Once these rules were defined, developers quickly applied for permits to build many new power plants in California, only to confront a time consuming state siting review process and local community opposition to power plants located near where they lived or worked. This slowed the pace of investment in and completion of new power plants.

Electricity demand in California and the rest of the WSCC grew much more quickly between 1996 and 2000 than had been anticipated. The excess capacity situation that contributed to the pressures for reform in 1993 gradually disappeared as electricity demand grew and no new generating capacity was completed during the four-year period of uncertainty over the new rules of the game. By 1999, it was clear that generating supplies had tightened considerably. While there was a significant amount of new generating capacity in the permitting and construction pipeline in California and some

other Western states, the first new plants did not emerge from this pipeline until early in the summer of 2001.

At the state level, nothing was done to speed up the siting review process or to otherwise facilitate completion of new generating plants. Nor did the CPUC endeavor to make reforms in retail market institutions and wholesale purchasing rules in the face of a growing amount of energy being purchased on the spot market as the utilities completed the divestiture of their gas-fired power plants. Moreover, relations between FERC, the CPUC and the ISO began to deteriorate as FERC began to put more pressure on the California parties to implement reforms that more closely reflected FERC's views on how to fix the problems. Faced with forecasts of potential shortages over the next few years, in 1999 the ISO did initiate a program to contract with new peaking plants if they could be in operation by summer 2000. This program was not successful.

Despite the problems experienced in 1998 and 1999, competitive wholesale market prices for power were reasonably close to pre-reform projections between April 1998 and April 2000.[32] Table 1 displays the average monthly day-ahead price in the PX for the period April 1998 through January 2001. The PX stopped operating after January 2001 and the prices for the February through May 2001 period are the average hourly prices for energy purchased by the ISO to balance the system. (In this section I will focus on the prices from April 1998 through April 2000, prior to the "crisis".) These prices roughly reflect expectations at the time the restructuring process began prior to May 2000. It was expected that average hourly wholesale prices would start at about

[32] Plus about 10% for ancillary services costs.

$25/Mwh and rise to about $30/Mwh as excess capacity was gradually dissipated.[33] Ancillary services prices were expected to be much lower than were realized, about 2% of the cost of generation service rather that the 10-15% realized in practice. All things considered, wholesale prices prior to May 2000 were perhaps 15% higher than they would be in a system without these design flaws. Indeed, the retail rate freeze for SDG&E's customers ended at the end of 1999, and they received the benefits of lower wholesale prices during the first five months of 2000. In March 2000, the California Energy Commission continued to publish projections of wholesale market prices in the PX for 2000 and beyond which were in the $28 to $35/Mwh range.[34] California officials did not express much concern about the slow pace of new power plant developments, the growing dependence of spot markets to meet default service obligations, or the growing evidence that more fundamental reforms in wholesale and retail market institutions were necessary.

RETAIL MARKET PERFORMANCE

An important component of California's restructuring program was to give retail customers "choice" of their ESP. 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 the retail prices of generation service at about $65/Mwh for up to four years. Accordingly, it is inaccurate to characterize the associated reforms as "deregulation." Wholesale market prices were deregulated, subject to FERC's ongoing supervision and responsibilities under the

[33] California Energy Commission (2001).

[34] California Energy Commission (2001).

Federal Power Act,[35] but retail prices were fixed for up to four years. The utilities were forced to sell their generating plants, in order to facilitate the creation of a truly competitive wholesale market with several additional independent suppliers and to value any prudent costs "stranded" by competition. But they also 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. The share of customer demand served by ESPs by September 2001 is displayed in Table 2.[36] 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.[37] The CPUC initially rejected these requests and subsequently sharply restricted the kinds of forward contracts they could

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[35] The U.S. Congress has never "deregulated" wholesale power prices. The Federal Power Act requires FERC to ensure that wholesale prices are "just and reasonable." FERC has chosen to allow suppliers to sell at "market based rates" when they can demonstrate that they do not have significant market power. FERC then interprets wholesale prices as "just and reasonable" if they reflect the interplay of supply and demand in a competitive market without significant market power.

[36] These data are representative of most of the 1998-2001 situation. However, after September 2001, as wholesale prices continued to rise far above the regulated retail default service price, most of these customers were returned to utility default service. As this is written the CPUC is considering a proposal to abandon customer choice completely.

[37] The utilities nuclear, coal, and hydroelectric plants that had not been divested 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. The QF contracts were not a good hedge since the contracts provided for energy prices that were indexed to gas prices and AB1890 gave the QFs the ability to switch to being paid for energy based on the

sign and delayed required approvals of those forward contracts they did sign. As a result, a large fraction of California's electricity demand was being served through the utilities' purchases in a volatile wholesale spot markets; the utilities in turn were selling at a regulated fixed retail price.

CALIFORNIA MARKET MELTDOWN: 2000-2001

As the year 2000 began, the general view of policymakers in California was that there were a variety of wholesale and retail market problems that had to be addressed, but that there was no rush to fix them. After all, wholesale prices for generation service were lower than regulated cost-based prices had been, utilities were amortizing their stranded costs, there was a long queue of new generation projects trying to get permits to enter the market, and a number of reform initiatives were being discussed. In reality, California's new market arrangements were an accident waiting to happen. And in mid-2000 the flawed wholesale market institutions and the partial deregulation program suddenly confronted a run of very bad luck.

Phase I of the Market Meltdown: May through September 2000

In mid-May 2000 wholesale electricity prices began to rise above historical peak levels. (See Table 1) Prices increased dramatically in June and stayed high for the rest of the summer months. The wholesale prices prevailing between June and September 2000 where much higher than the fixed retail price that the utilities were permitted to charge for retail service. SCE and PG&E began to lose a lot of money: the losses mount up fast when you are buying at $120/Mwh and selling at $60-$65/Mwh! SDG&E's retail prices had been deregulated at the beginning of 2000. During the first half of 2000, SDG&E

PX price.

bought electricity in the wholesale spot markets and passed along the associated wholesale market costs to its default service customers (in addition to regulated distribution, transmission and other charges for non-competitive services). However, as retail prices rose along with wholesale prices during summer 2000, there was a loud negative public reaction which ultimately led the California legislature to cap SDG&E's default service prices at $65/Mwh.[38]

By September 2000, SCE and PG&E were pleading with the CPUC to lift the retail rate freeze and to allow them to charge customers for the full cost of purchasing wholesale power on their behalf. They argued that the market value of their remaining plants now exceeded their book value, declared their generation-related stranded costs collected, and requested the end of the rate freeze that was supposed to take place when stranded cost recovery was completed based on power plant sales or alternative market valuation of remaining generating assets. The CPUC refused to do so and there were no retail price increases permitted for the balance of 2000. In an effort to constrain wholesale prices, the California ISO reduced the exiting real-time price cap from $750 to $500 in July 2000 and to $250 in August with FERC's approval. This $250 price cap stayed in effect until early December 2000.

Why did wholesale prices rise so quickly and dramatically above projected levels? There are five primary *interdependent* factors: (a) rising natural gas prices, (b) a large increase in electricity demand in California, (c) reduced imports from other states, (d) rising prices for NOx emissions credits, and (e) market power problems.

[38] Unlike SCE and PG&E, SDG&E will theoretically be permitted to recover the difference between their wholesale market purchases and the $65/Mwh cap sometime in the future. The terms and conditions under which such recovery would take place have not been determined and SDG&E carries these costs as a "regulatory asset" on its books.

Beginning in May 2000 natural gas prices began to rise and eventually soared to unprecedented levels across the country. Figure 2 displays spot market natural gas prices at Henry Hub (the most important natural gas trading hub located in Louisiana) and the spot price for natural gas delivered to the Southern California border. While natural gas prices soared throughout the U.S. during the second half of 2000, for reasons that are still not well understood, spot prices for natural gas delivered to California rose to levels as much as five times higher than those in the rest of the U.S. by December 2000. Rising natural gas prices have a direct effect on spot market prices for electricity in California because California has a lot of natural gas fired generating capacity and it is the gas-fired plants that typically balance supply and demand in the wholesale market during most hours during the summer months.

Electricity demand also increased significantly throughout the Western U.S. due to abnormally hot weather in May and June,[39] and strong economic growth. Table 3 displays the average monthly demand in the California ISO for 1999 and 2000. It is evident that demand in California increased dramatically during the first eight months of 2000 compared to 1999.[40] Since retail consumers did not pay prices that responded to movements in wholesale market prices, they had no incentive to reduce demand as wholesale prices soared. Moreover, ESPs could not compete with the fixed utility retail default service rate and had incentives to return the customers with whom they had

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[39] Peak demand in California was no higher in 2000 than it was in 1999. However, average demand increased significantly during May and the summer months.

[40] The extremely large increases in May and June are due to unusually hot weather.

contracts to the utility default service so that they could increase profits by selling their power in the wholesale market.[41]

The rest of the WSCC experience a similar surge in demand during Summer 2000, and the heat waves in May and June were spread across the entire region. This reduced supplies available for export to California from other states, supplies upon which California has historically depended to balance supply and demand. Unusually low water levels in the Northwestern U.S. further reduced the availability of imported hydroelectric power into California.[42] Table 4 displays the average monthly imports of power into California for 1999 and 2000. While wholesale prices are much higher in 2000, imports were much lower.

In the early 1990s, the South Coast Air Quality Management District (SCAQMD), which covers Los Angeles and surrounding areas, implemented an innovative "cap and trade" system (RECLAIM) to control emissions of NOx and some other air pollutants from power plants and other large stationary sources (e.g. oil refineries). Under this system, a plant had to turn in enough permits or "credits" to cover its emissions each year addition. Each plant was allocated a (declining) number of permits each year. These permits were tradeable, so a source that did not require all of the permits it needed could sell than to other sources that had to cover emissions exceeding its permit allocations. Since there is a market for these permits, they represent

[41] Let's say that an ESP has agreed to supply a retail customer for a year at $60/Mwh, lower than the utility default service price of $65/Mwh. Assume has well that the ESP had hedged its supply obligation by entering into a contract with a generator at $58/Mwh. When wholesale prices rose to $120/Mwh, it became profitable for the ESP to return the retail customer to utility default service, compensate her for the $5/Mwh difference between the default service price and the contract price, and then resell the wholesale power under contract at $58 for $120 in the wholesale market.

[42] California also depends on a significant amount of in-state hydroelectric generating capacity.

either a direct variable cost or an opportunity cost to generators that increases the costs of producing electricity by plants covered by the cap and trade program by their emissions rate times the prices of NOx emissions permits.

Until early 2000, the market prices for these permits were very low and the number of permits allocated to power plants generally exceeded their emissions. However, between April 2000 and September 2000, the price of pollution permits required to cover NOx emissions from power plants in the Los Angeles area increased by a factor of nearly ten as the supply of permits continued its planned decline under RECLAIM and demand for permits increased as the gas-fired generators were running more than they had in recent years in response to a large increase in the residual (net of imports) demand for electricity in the CAISO area. By September 2000, NOx permit prices increased marginal supply costs from a gas-fired steam unit in the SCAQMD by $30 to $40/Mwh and increased the marginal supply costs from a peaking turbine by $100 to $120/Mwh.[43] The RECLAIM program affects only the fossil generating units in the SCAQMD, which account for about 60% of the gas-fired capacity in the state. However, the spot market in California (indeed the entire WSCC) typically clears based on the highest unit with the highest marginal cost in Southern California when there is not congestion between Northern and Southern California.

All of these supply and demand factors are integrated together in a simple fashion in Figure 3. This figure represents the marginal costs curve for all of the gas-fired generating units in California given the specified assumptions about natural gas and NOx

[43] A conventional gas-fired steam unit without special NOx controls, emits roughly 1 pound of NOx per Mwh. A combustion turbine emits 3 to 4 pounds of NOx per Mwh. A conventional gas-fired steam generating unit with with Selective Catalytic Reduction (SCR) technology to reduce NOx emissions would emit about 0.1 pounds of NOx/Mwh.

credit prices which roughly reflect the situation during July 2000. These gas units lie at the top of the competitive electricity supply curve. The lowest marginal cost curve depicted in Figure 3 reflects gas prices prevailing in summer 1999. The next highest marginal cost curve reflects gas prices prevailing in early summer 2000. The highest marginal cost curve incorporates the effect of NOx permit prices on marginal generation costs. The inclusion of the NOx permit costs leads gas-fired units in Southern California to move toward the top of the supply curve and both shifts the supply curve upward and makes it more inelastic at higher output levels. Figure 3 makes it clear that tt any given demand level, competitive market prices would have risen significantly as a result of higher input prices. Reduced imports would have increased the residual demand on California supply resources, pushing production further up the supply curve and leading to increased prices in a competitive market. Higher demand in California in 2000 pushed production even further up the supply curve and increases competitive prices further. No new generating capacity had entered the market to shift the supply curve outward and to moderate competitive prices.

Accordingly, even if California's wholesale market had been perfectly competitive, wholesale prices would have risen considerably due to changes in supply and demand conditions. However, previous analysis by the ISO's market surveillance unit and other analysts had already made it clear that California's wholesale spot markets where not perfectly competitive during relatively tight supply conditions.[44] As previously noted, during low and moderate demand conditions, the energy markets appeared to be quite competitive, with day-ahead prices observed to be reasonably close

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[44] CAISO MSC Report, October 1999; Borenstein, Bushnell and Wolak (1999).

to estimates of marginal cost. When demand got very high, however, it was clear that the market clearing prices in the spot market were far above the marginal cost of the most expensive generators in the region. Since there is virtually no real demand elasticity yet in these markets, a during peak periods most demand is satisfied with purchases in the spot markets, it is evident that as demand grows and supply gets very tight, generators realize that a small amount of capacity withholding, even with moderate levels of concentration, can lead to large price increases. The combination of (completely) inelastic demand and tight supplies created opportunities for individual suppliers to exercise market power *without* engaging in collusion, driving prices up still higher.

These market power problems and associated strategic behavior by suppliers became more severe during Summer 2000 than they had been in 1998 and 1999. Work that I have done with Ed Kahn indicates that about a third of the wholesale price can be attributed to market power during June, July, August, and September 2000, after accounting for changes in fundamental supply and demand conditions.[45] Other studies have found similar results for the balance of 2000.[46]

These factors all contributed to an explosion in wholesale market prices during the summer of 2000. By September, utilities were paying nearly three times as much for power in the wholesale market than they could charge for at retail and began to confront serious cash flow problems requiring them to borrow increasing amounts in short-term credit markets.

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[45] Joskow and Kahn (2001a, 2001b)

[46] For example, see Eric Hildebrandt, "Further Analyses of the Exercise and Cost Impacts of Market Power In California's Wholesale Energy Market," March 2001. This studies apply and extend methods similar to those developed by Wolfram (1999).

The Meltdown Continues: October through December 2000

Many government officials expected to see wholesale prices fall as the peak summer season came to an end. Federal and state government officials hoped that a drop in wholesale market prices during the off-peak Fall, Winter, and Spring months would give them time to figure out what they needed to do in order to respond to market behavior and performance problems and the utilities' growing financial problems. However, wholesale electricity prices did not fall as expected. While demand fell as usual after the summer months, natural gas prices continued to rise, imports remained low, NOx credit prices remained high and, most importantly, unusually large amounts of generating capacity was out of service and unavailable to supply electricity. Figure 4 displays the difference in outages between 1999 and 2000 for October and November.[47] Power suppliers argue that their plants were not supplying because they had run them so hard during the summer that they had broken down, that some were down to have new NOx emissions control systems installed, and others were down due to other environmental constraints. California government officials argue that the plants had been withdrawn from service at least partially for strategic reasons.[48] Whatever, the reasons, from November 2000 until May 2001, as much as 16,000 Mw of the generating capacity within the CAISO area (about 35% of total capacity) was not in service and was

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[47] I am grateful to Frank Wolak for providing these data to me.

[48] In response to these allegations, FERC "audited" several of these plants, many through telephone inquiries, and concluded that there was no evidence that they were down for strategic reasons. However, the quality and conclusions of this study was recently criticized by the General Accounting Office, an independent investigative arm of the U.S. Congress. See General Accounting Office (2001).

unavailable to supply electricity during this period. This is roughly double the typical historical planned and forced outage rates.

Wholesale prices fell modestly in October 2000 and then soared to new heights in November and December 2000. By mid-December, the utilities were paying almost $400/Mwh for power in the wholesale market and reselling it for $65/Mwh at retail. By the end of December, the utilities were losing about $50 million per day. The utilities' continuing requests for permission to increase retail prices to provide revenue to finance their growing debts to wholesale suppliers were either rejected or deferred for further consideration by the CPUC. Similarly, repeated requests to FERC to deal with market power problems and other market failures were also ignored until mid-November 2000.

In a report and order issued on November 15 (and a subsequent order issued December 15), FERC concluded that the California markets were fundamentally flawed, and pursuant to its legal responsibilities under the Federal Power Act, found that wholesale prices were "unjust and unreasonable." It proposed a number of short, medium, and long-term changes in California's markets. These included a misguided effort to shrink the spot market by requiring the utilities to self-schedule their own remaining generating capacity against their retail default service demand, buying only their net short in the PX and ISO, replacing the "hard" $250 price cap then in place with a "soft" $150 cap, and imposing a $100/Mwh under-scheduling penalty in an effort move more transactions from the real time market into forward markets.[49] Reflecting an

[41] FERC ordered the utilities to "self-schedule" their own remaining generating capacity and contracts against their default service demand. This requirement reflected FERC's confusion about how the wholesale markets worked, since the utilities were already effectively doing this. FERC required the utilities to purchase only their "net short" in the wholesale market, preferably through bilateral contracts rather than through the PX and ISO's spot markets. The primary effect of these actions was probably to put the PX out of business. FERC also imposed a large "underscheduling" penalty to encourage more forward contracting. Under the "soft cap" proposal, sales made to the PX or ISO at prices less than or

increasingly hostile and angry relationship between federal and state regulators, FERC also made it clear that it was within California's power to deal with many of the causes of the growing crisis, in particular the utilities' growing credit problems, and that it expected California to act swiftly to take actions to respond to the emerging crisis. These actions included increasing retail prices to reflect wholesale market prices, introducing real time prices at the retail level, allowing utilities to enter into forward contracts, speeding up permitting of new power plants, etc. Unfortunately, California government officials did nothing during 2000 to respond to the emerging crises, blaming lax FERC oversight and the unregulated suppliers' strategic behavior as the primary cause of the rising wholesale prices, and suggesting that the utilities were not being truthful about their credit problems. Moreover, the relationship between FERC and government officials in California deteriorated even further.

After FERC's new price mitigation rules were implemented in mid-December, wholesale market prices soared to $400 cents/Mwh. With no retail price increases permitted by the CPUC, PG&E and SCE were quickly approaching insolvency as they found it increasingly difficult to finance the huge uncollected wholesale power charges they had incurred over the previous 12 months --- reported to be about $12 billion by the end of December 2000.[50] It should be noted, however, that there is a roughly 60-day lag

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equal to $150/Mwh were deemed to be reasonable. Sales made above $150/Mwh had to be "cost justified" by the suppliers. This was accompanied by filing requirements. This new cap probably made things worse rather than better. By December, gas prices had risen so high that few gas units could cover their fuel and NOx credit costs at $150. Moreover, suppliers could "cost justify" their sales to the PX and ISO based on the purchase price of the power. Accordingly, the regulations could be evaded by a generator simply by selling power first to a marketer and then the marketer could resell it to the PX or ISO. This created incentives to daisy-chain the power sales around the WSCC. In the end, FERC did not have the resources to review all of the information filings justifying the bulk of transactions which took place above the $150/Mwh soft cap.

[50]SDG&E was in a better situation since it had a separate law which committed California to allow it to

between when wholesale purchases are made and when the bills must be paid. So, while the utilities had incurred substantial financial obligations to power suppliers, the large obligations accrued in November and December had not yet been paid as the year 2000 ended. During December, several suppliers claimed that they were running up against their internal credit limits and would not provide further supplies to the market unless payments were accelerated to reduce their accounts receivable. Accordingly, credit problems may have further reduced supplies available to the market, contributing to the continued increase of wholesale prices during December 2000.

The State Takes Over: January 2001 through June 2001

By the first week in January 2001, it became clear that California regulators would not raise retail prices sufficiently to restore the utilities' credit.[51] Both the PX and the ISO are non-profit entities whose credit depended entirely on the credit worthiness of the utilities which were the primary buyers using these entities. Power suppliers began to refuse to offer supplies to them for fear of never getting paid. In Mid-January PG&E and SCE announced that they did not have enough cash to pay power suppliers as bills from the PX and ISO became due. They ceased making payments for power supplies, including payments owed for supplies delivered in November and December 2000, as the associated bills became due. They also stopped making payments on commercial paper and some other financial obligations as they became due.

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recover these balances from customers sometime in the future. This was a good enough promise for it to get private financing to cover its wholesale power procurement debts.

[51] On January 3, the CPUC finally responded to utility requests for retail price increases to help to pay for wholesale power costs. It approved a temporary 1 cent/Kwh surcharge on retail prices. Later in the month it approved accounting changes that effectively recaptured net revenues that have previously been used by the utilities to amortize their stranded costs. The surcharge was not nearly enough to pay ongoing wholesale power costs, let alone any of the debts to power suppliers accumulated over the previous month.

PG&E and SCE were effectively insolvent by early January 2001. Supply shortages and involuntary curtailments of supplies to individual consumers soon followed. The PX ceased operating its day-ahead markets on January 31, 2001 in response to utility credit problems and new FERC rules regarding utility scheduling of their remaining generating capacity and contracts.[52] DOE emergency orders and then federal court orders requiring generators in California to continue to supply were the only thing that kept the lights from going out in California at the end of 2000 and in early 2001. In just six months, what had been a modestly successful electricity reform program had completely collapsed.

By the end of January, it became clear that if the State of California did not take action, the lights would go out as suppliers would refuse to generate electricity unless they were assured of payment by a credit-worthy entity. The Bush administration, which took office on January 20, 2001, indicated that it would no longer use federal authority to force generators to keep supplying electricity without assurances that they would be paid. Since the utilities had no funds to pay them (since retail rates remained much too low to cover ongoing wholesale power supply costs and the utilities could no longer finance their rapidly growing debt in the credit markets), the state of California, through California Department of Water Resources (CDWR), began to buy power to meet some of the utilities' net short positions sometime in January 2001 and continues to do so today.[53] CDWR spent about $8 billion through May 2001 doing so.

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[52] The PX filed for bankruptcy on March 9, 2001.

[53] It was unclear for several months whether the CDWR was buying enough power to cover all of the utilities' net short position. At first, CDWR indicated that it was only buying power that was offered at a "reasonable" price. By June CDWR indicated that it would pay for all of the power needed to cover the utilities' net short position, though not for power purchased under contract from QFs.

At the direction of Governor Davis, CDWR also began to negotiate long-term contracts (up to 20 years) with generators and marketers. The motivations for entering into long-term contracts was to obtain better prices than were expected to be available in the spot market, to provide incentives to generators to make their plants available to supply electricity, to mitigate incentives to exercise market power, and to facilitate completion of new generating plants. The details of these contracts are still being released, but in the aggregate they appear to involve commitments of about $50 billion spread primarily over the next ten years. It is quite clear, however, that the terms and conditions of these contracts would have been much more favorable if the state had encouraged the utilities to enter into longer term contracts in 1999 or even during the summer of 2000 when they requested this authority. Moreover, earlier contracting activity likely would have mitigated some of the problems that emerged during the late fall and Winter of 2000/2001. Generators would contracts would have been more likely to firm up gas supplies and led more gas to have been placed in storage earlier. The Governor also announced a number of measures to speed siting approvals for new generating plants and to encourage conservation. On March 27, the CPUC announced that retail prices would be increased by about 40% and retail consumers began to see these price increases in their bills in June 2001.

Despite these efforts, as much as a third of the generating capacity in the CAISO's areas remained out of service for most of the Winter and Spring of 2001 and the availability of imports remained low. As a result, electricity supply emergencies were in effect for most of this period, and there were several days of rolling blackouts.

Predictions made during Spring 2001 for the coming Summer were bleak as well.[54] There was a serious drought in the Northwest which meant that little electricity would be available for export to California during the peak summer months. Demand was projected by the ISO to continue to grow from 2000 levels under normal weather conditions, while little new generating capacity was expected to be completed until the end of the summer. Forward prices for natural gas remained high. Forward prices for the summer months were as high as $500-$700/Mwh during this period.[55] The ISO and WSCC predicted that there would be hundreds of hours of blackouts in California and other areas of the WSCC during the coming summer with normal weather conditions.

In response, the California government intensified its conservation efforts, intensified efforts to speed up the completion of new plants, and continued to enter into forward contracts with suppliers for up to 20 years. The SCAQMD effectively took electric generating plants out of the RECLAIM program, ending their participation in the cap and trade program and replacing the NOx credit trading system with a $7.50/pound penalty for exceeding emissions limits.

With predictions of hundreds of hours of blackouts for the coming summer, and extremely high forward prices for electricity, during Spring 2001 California and other Western states also put heavy pressure on the Bush administration to restore caps on wholesale prices and to force generators to make all the electricity they could produce available to the market. FERC responded slowly to the political pressure as it considered whether or not to adopt some type of effective price mitigation program to replace the

[54] California Independent System Operator (2001)

[55] *MegawattDaily*, April 11, 2001, page 5.

soft cap that had been put in place in December 2000. On April 26, FERC adopted a new price mitigation plan that requires generators to bid all available supplies that had not already been scheduled into the ISO's real time auction market. It also adopted bid caps for these real time supply offers when operating reserves fell below 7% (Stage 1 emergency condition). Each generator's bid was capped at its marginal generating cost. The bids were then stacked up lowest to highest and the highest bid to clear the market determined the market-clearing price in that hour. This mechanism had a number of loopholes that were likely to make it ineffective, including the ability of resellers to easily evade the caps. On June 18, FERC modified this price mitigation plan by applying it to all hours and to all spot sales of electricity in the WSCC. The new plan went into effect on June 20.[56] Finally, FERC instituted a proceeding to resolve claims by California that they were overcharged for power in 2000 and 2001 and held out the possibility of substantial refunds.

During the first week in June 2001, spot and forward wholesale prices finally began to drop quickly. By the end of June spot prices had returned to levels that had not been seen since mid-May 2000 and forward prices for the rest of the year dropped dramatically. Indeed, they fell well below the prices in the contracts negotiated by CDWR. This price break was accompanied by relatively low seasonal demand reflecting moderate weather throughout the West, as well as customer conservation efforts in California, significantly lower natural gas prices, large amounts of generating capacity

[56] This new plan has a number of deficiencies. It does not adjust the price cap quickly enough to reflect changes in the spot market price of natural gas and does not adequately distinguish between gas prices at different locations in California. It is also unclear whether the CAISO is implementing the FERC mitigation plan as intended, since there have been almost no supply emergencies since the June 19 FERC order as this is written.

returning to service after being out of service for most of the Winter and Spring, and more imported power available from the Northwest and Southwest than had been expected. Consumers appear to have begun to respond to the publicity surrounding the crisis, expected price increases, and new energy efficiency programs sponsored by the state by reducing demand significantly from predicted levels beginning in February and continuing into the summer. Table 5 displays the average demand in the CAISO for the first six months of 2000 and 2001. Demand in 2001 is significantly lower than Demand during 2000.[57] In early July, three new power plants began operating in California, the first new generating capacity in nearly 10 years. Additional generating capacity will come on line later this summer and much more is due to be completed next year. It is fairly clear that FERC's latest price mitigation program, and the intense scrutiny that suppliers are now under in the regulatory arena, the courts and the media, have provided powerful incentives for the suppliers to be on their best behavior during June and July 2001 as generating unit availability has been relatively high and bidding behavior is generally more competitive.[58]

By July 2001, many in California had concluded that the crisis was over. Actions taken by California and FERC have clearly had a favorable impact on wholesale electricity prices, supply, and demand in California and the rest of the West. However, a few weeks of experience during a period when demand was unusually low, should not be interpreted as demonstrating that the system has been fixed.[59] California has still not

[57] My preliminary analysis suggests that the reduction in demand is much larger during peak than off-peak periods.

[58] California ISO Market Monitoring Report, July 5, 2001. "The analysis shows that instances of bidding in excess of operating costs have declined significantly since the last report." Page 2.

[59] During the first week of July 2001, temperatures rose throughout the WSCC and demand rose rapidly.

addressed the fundamental market and network management design problems that were identified before and during the crisis. State funds are providing the financial resources to keep the system operating on a day-to-day basis and the state is now saddled with tens of billions of dollars in long-term contracts that are likely to carry prices well above market levels. The costs of these contracts will be paid either through future electricity prices, or state tax revenues, or a combination of both. Retail prices are now much higher than they were in 1996 when the restructuring process began. Moreover, the vision for the future of California's electricity sector remains murky as this is written as the State of California has effectively taken over the state's electric power industry. Stay tuned for further details.

LESSONS LEARNED

The problems in California are not inherent problems with "deregulation," but result from the way that California implemented its reforms, combined with a good deal of bad luck and ineffective government responses to its effects. Similar reforms in other countries and other regions of the U.S. have been more successful in achieving their goals. The most important things to learn from the California experience about designing and implementing competitive market reform programs for electricity are:

- Electricity has unusual physical attributes that make the design of well functioning competitive wholesale power markets a significant technical challenge. Effective market design requires substantial technical expertise and careful application of lessons learned from international experience. Market institutions and residual regulatory mechanisms need to be designed to be robust

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There were Stage 1 and Stage 2 emergencies in California on July 2 and July 3. The subsequent period (through July 22, 2001) remained cool and CAISO peak demand quite low.

to extreme contingencies. Market power problems must be addressed both initially and as evidence about actual market performance and supplier behavior emerges as the markets operate. Responsible regulators need to be in a position to evaluate alternative market design frameworks and to approve only those that are likely to perform well. They must have the capabilities to identify serious market performance problems and to develop and apply reforms to fix them. California relied on "market design by committee" and allowed mindless free-market rhetoric and interest group politics, to ignore technical realities, international experience and common sense. It did not take into account extreme contingencies. Responsible state and federal officials were not sufficiently engaged with the details of this process and responded too slowly to problems.

- Competitive electricity markets will not work well if consumers are completely insulated by regulation from wholesale market prices. California deregulated wholesale prices, but failed to deregulate retail prices or to allow the utilities to use forward contracts to hedge their default service supply and pricing obligations. The terms and conditions of default service made it necessary for utilities to buy at an unregulated hourly wholesale spot market price and to sell at a fixed regulated retail price for up to four years. Not only did this drive the utilities to the point of insolvency after wholesale prices rose above the fixed retail price in June 2000, but it has also made it very difficult for competing retail suppliers to attract customers or for consumers to respond to high prices by reducing consumption.

- Spot electricity markets work very poorly when supplies are tight; the combination of relatively tight supplies and extremely inelastic demand means that prices can rise to extraordinary levels and are much more susceptible to market power problems than when supplies are abundant. One way to help to protect consumers from volatile and excessive spot markets for electricity is to ensure that a large fraction of consumer demand is covered by longer term fixed price contracts negotiated under competitive conditions well in advance of spot

market crises. These contracts both protect consumers from price volatility (they act like an insurance policy) and reduce incentives suppliers have to exercise market power when supplies get tight. Such contracts can also facilitate financing of new power plants. A good retail procurement framework, whether it relies of utility distribution companies, competitive electricity service providers (ESPs), or a combination of both, must assure that a large fraction of retail demand is being met with longer term fixed price contracts and only a small fraction fully exposed to the spot market.

- In addition, the default service option for larger commercial and industrial consumers should be to purchase their electricity at real time prices. Real time pricing at the retail level allows consumers to express their individual preferences for reliability, introduces demand elasticity into the spot *wholesale* market and this in turn dampens price volatility and helps to mitigate supplier market power. (These customers should also have the option of hedging some or all of their demand with contracts purchased from electricity marketing intermediaries or their distribution company.) California both refused to allow the entities (the utility distribution companies) with the responsibility to procure supplies for 85% to 90% of the retail demand to enter into forward contracts *and* ignored proposals for demand response programs that would allow customers to respond to wholesale price spikes by reducing consumption.

- The primary benefits of electricity sector reform will occur in the long run as a consequence of investments in new more efficient power plants, the introduction retail risk management, demand management and energy efficiency services, and continuing innovations on both the supply and demand sides. Speeding the ability of developers to site and build new generating plants and providing good incentives to expand transmission networks, all of which meet reasonable environmental standards, is essential for good long run market performance. Removing unnecessary administrative barriers to entry allows supply to increase more quickly as market conditions make it profitable to do so and will reduce the

likelihood of extreme contingencies. California focused too much on illusive short run gains from low-priced power that was available when there was excess capacity and focused too little on creating sound institutional arrangements to support investments in new generation and transmission facilities.

- All electricity market reform programs have experienced some problems at the outset. Mid-course corrections have almost always been necessary to mitigate market performance problems. When market performance problems emerge, government officials must act quickly and decisively to fix the problems. Ongoing market reforms and regulatory "mitigation" initiatives designed to remedy serious market performance problems should be an *expected* feature of the process of creating efficient competitive wholesale electricity markets. If the California and federal regulators had done so in September 2000 when the current problems became crystal clear, they would have reduced significantly the ultimate magnitude of the crisis. Unfortunately, both the CPUC and FERC acted too slowly and ineffectively as the crisis deepened and spent most of their energies pointing fingers of blame at one another rather than working together cooperatively to find a solution.

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FIGURE 1
CALIFORNIA ISO/PX

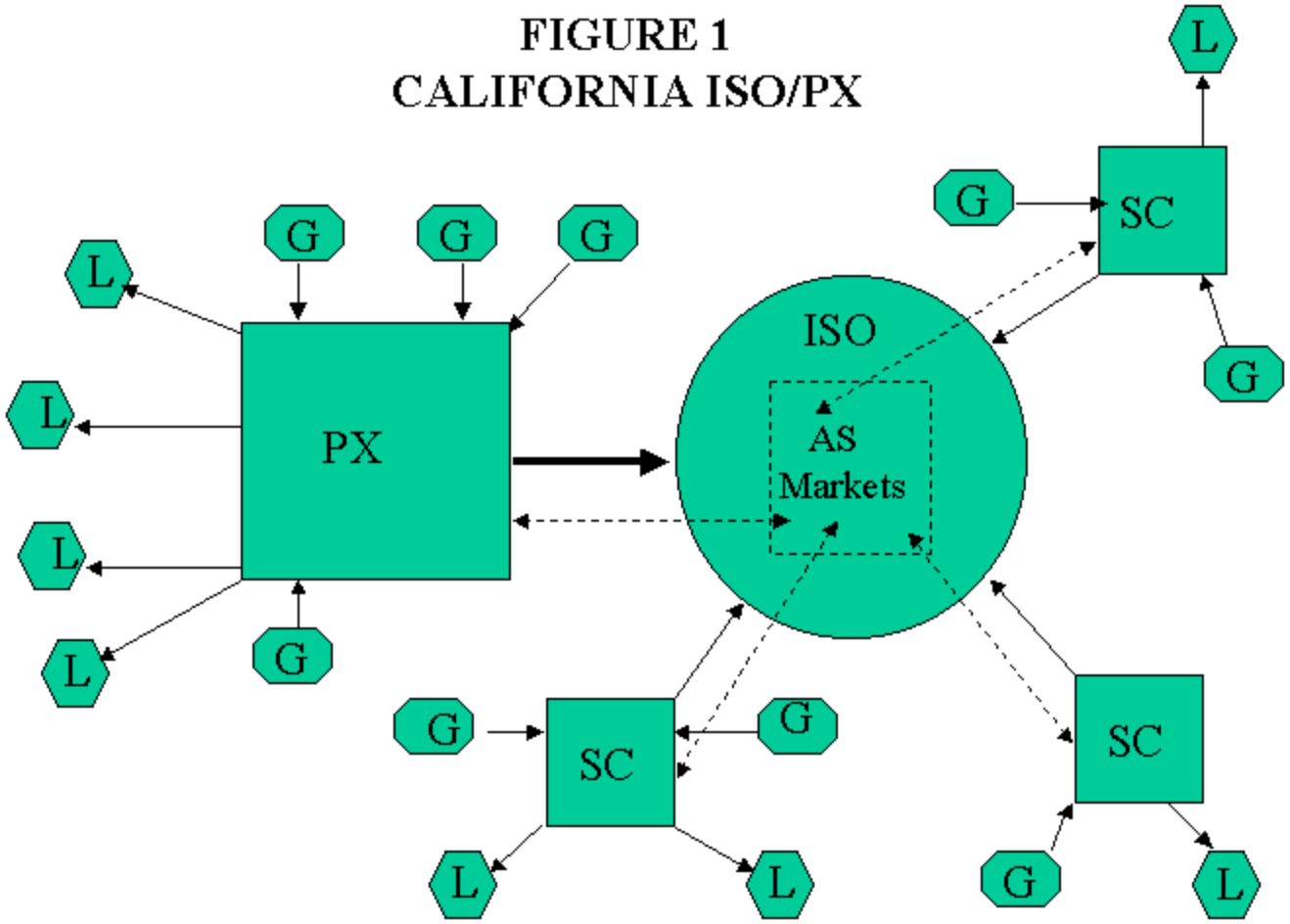
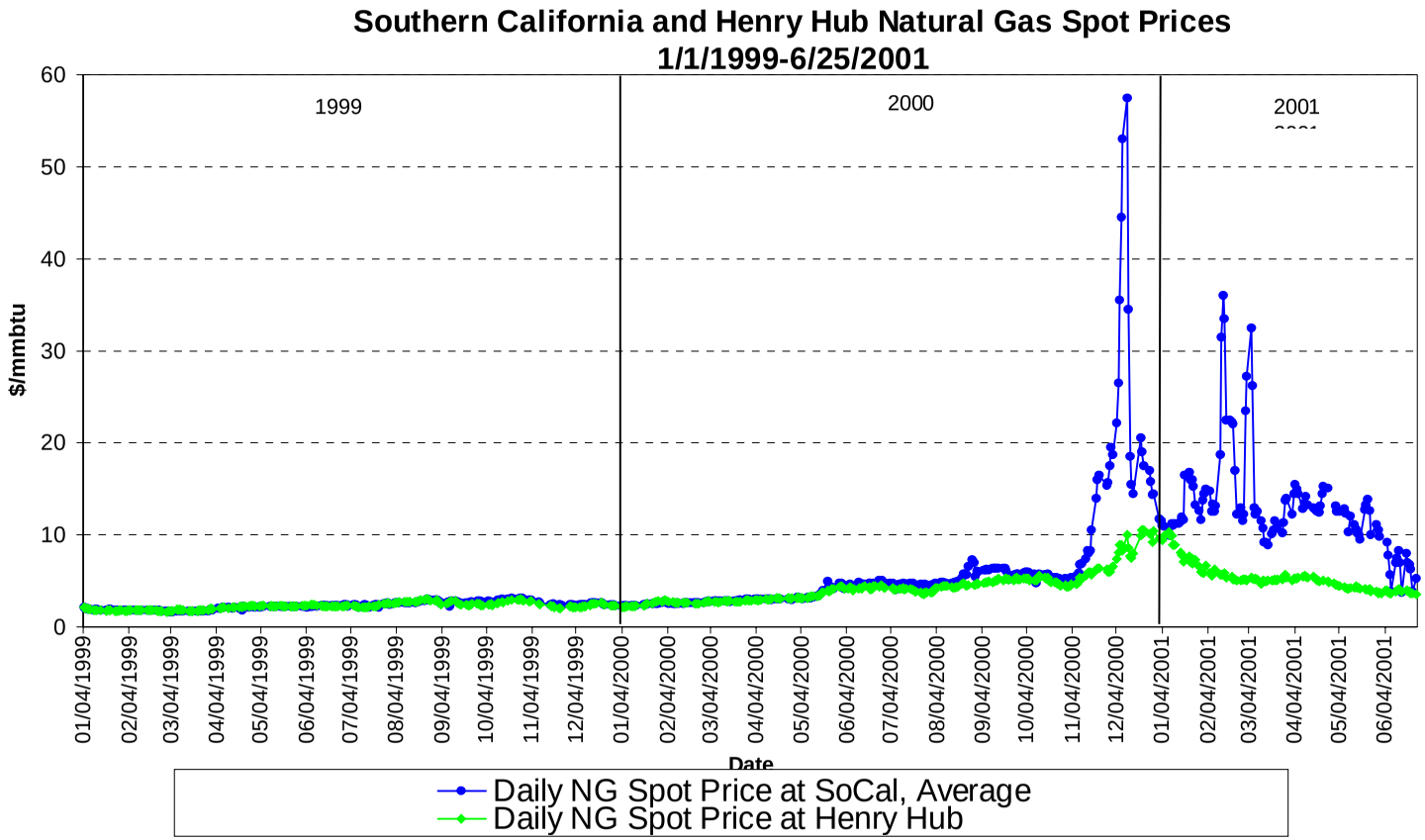


FIGURE 2


Southern California and Henry Hub Natural Gas Spot Prices
1/1/1999-6/25/2001
$/mmbtu
60
50
40
30
20
10
0
1999
2000
2001
01/04/1999
02/04/1999
03/04/1999
04/04/1999
05/04/1999
06/04/1999
07/04/1999
08/04/1999
09/04/1999
10/04/1999
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08/04/2000
09/04/2000
10/04/2000
11/04/2000
12/04/2000
01/04/2001
02/04/2001
03/04/2001
04/04/2001
05/04/2001
06/04/2001
Date
Daily NG Spot Price at SoCal, Average
Daily NG Spot Price at Henry Hub

FIGURE 3

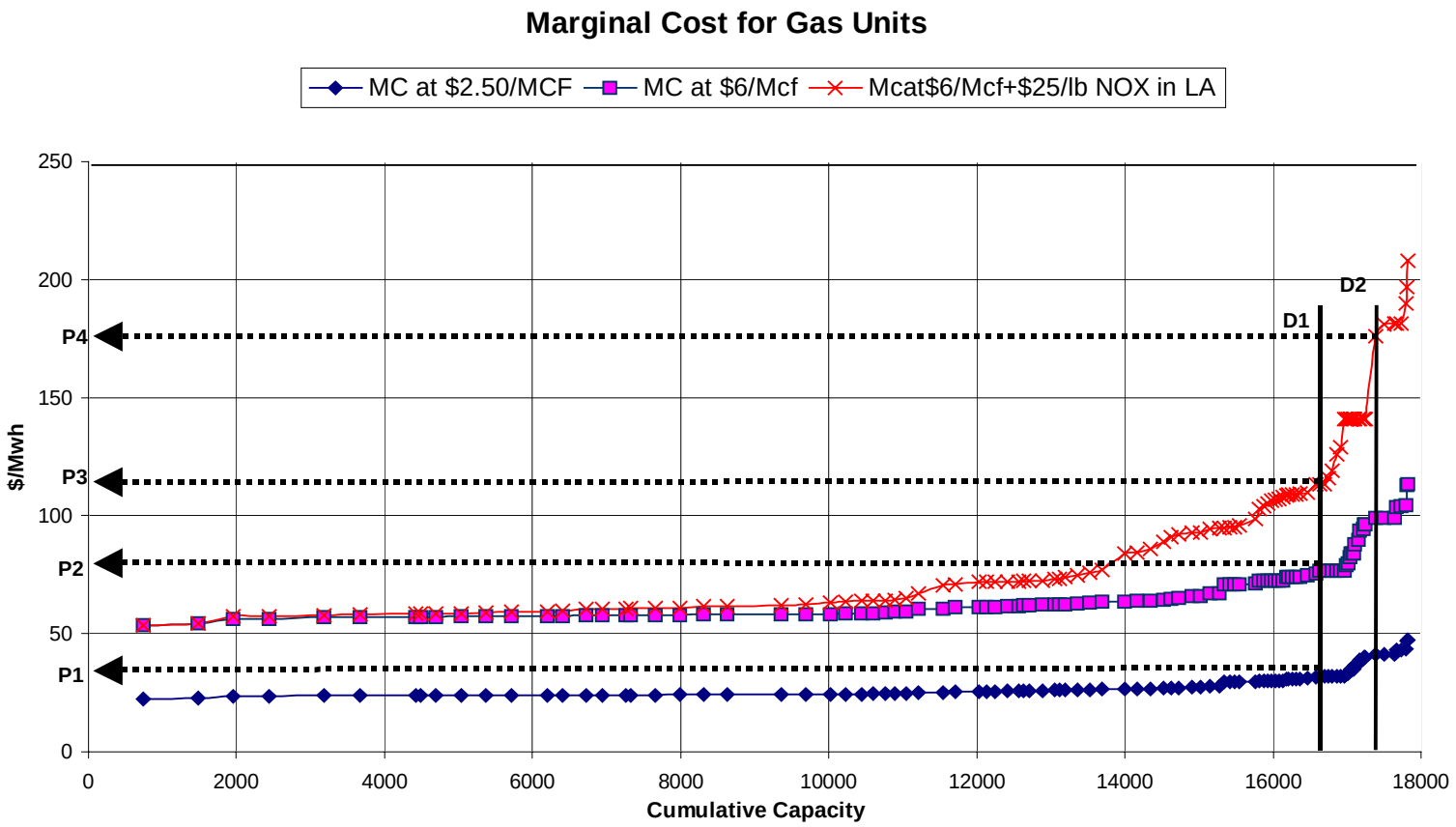
Marginal Cost for Gas Units
MC at $2.50/MCF
MC at $6/Mcf
Mcat$6/Mcf+$25/lb NOX in LA
$/Mwh
250
200
150
100
50
0
P4
P3
P2
P1
D1
D2
0
2000
4000
6000
8000
10000
12000
14000
16000
18000
Cumulative Capacity

FIGURE 4

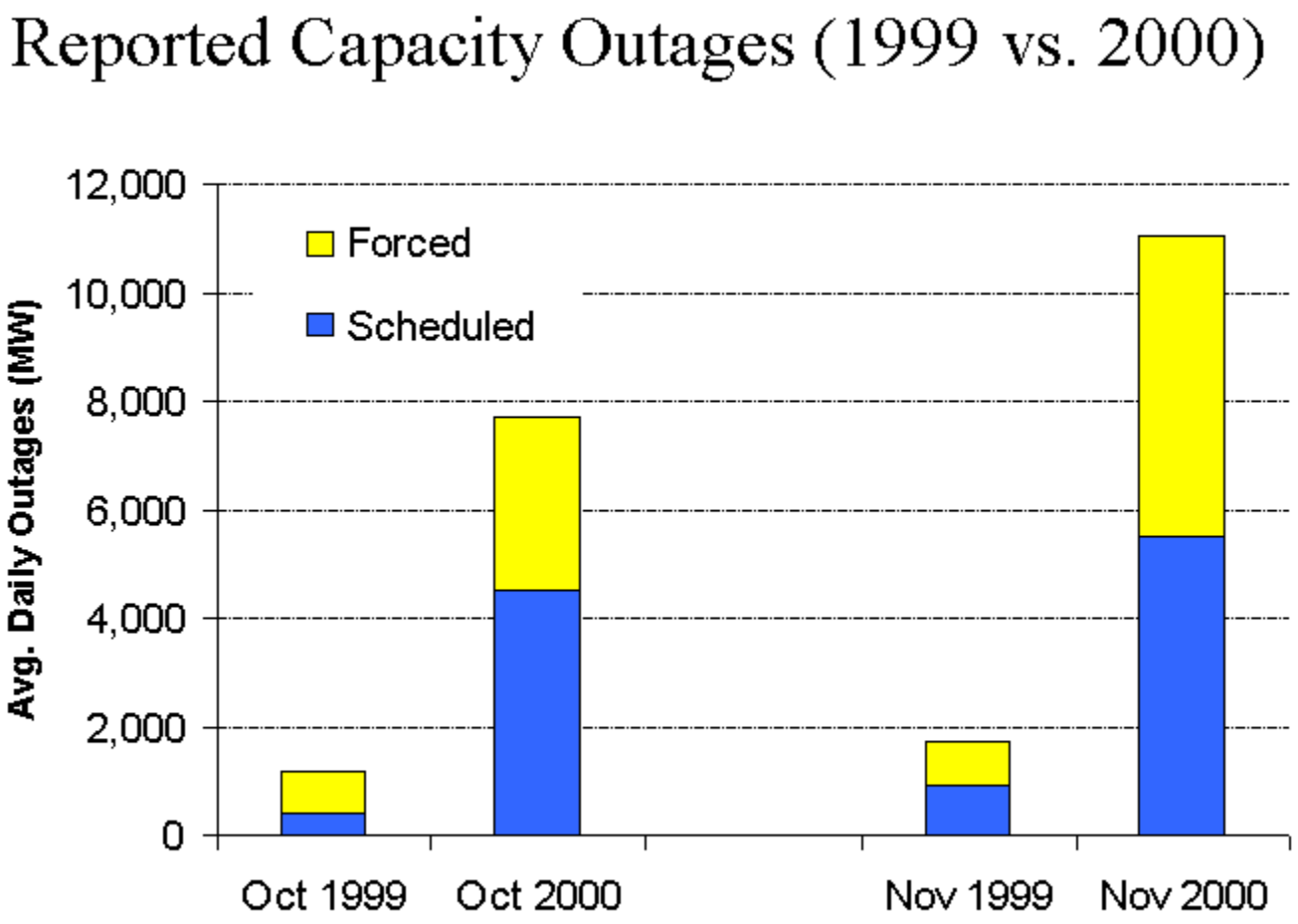
Reported Capacity Outages (1999 vs. 2000)
Avg. Daily Outages (MW)
12,000
10,000
8,000
6,000
4,000
2,000
0
Forced
Scheduled
Oct 1999
Oct 2000
Nov 1999
Nov 2000

TABLE 1

CALIFORNIA PX DAY-AHEAD PRICES
($/Mwh:Weighted Averages 7 x 24)

	1998	1999	2000	2001
January	-	21.6	31.8	260.2
February	-	19.6	18.8	363.0 (ISO)
March	-	24.0	29.3	313.5 (ISO)
April	23.3	24.7	27.4	370.0 (ISO)
May	12.5	24.7	50.4	274.7 (ISO)
June	13.3	25.8	132.4	
July	35.6	31.5	115.3	
August	43.4	34.7	175.2	
September	37.0	35.2	119.6	
October	27.3	49.0	103.2	
November	26.5	38.3	179.4	
December	30.0	30.2	385.6	
AVERAGE	30.0	30.0	115.0	

TABLE 2

CUSTOMER CHOICE IN CALIFORNIA 9/30/00
(% OF TOTAL LOAD)

Residential	2.0%
Commercial < 20kW	3.8%
Commercial 20kW – 55kW	12.8%
Industrial > 500 kW	27.4%
TOTAL	12.0%

TABLE 3

AVERAGE CAL ISO HOURLY DEMAND (MW)

MONTH	1999	2000	CHANGE %
JANUARY	24,013	25,516	6.3
FEBRUARY	24,194	25,585	5.7
MARCH	24,469	25,523	4.3
APRIL	24,166	25,329	4.8
MAY	24,271	26,883	10.8
JUNE	26,609	29,981	12.7
JULY	28,878	29,501	2.2
AUGUST	29,055	31,104	7.1
SEPTEMBER	27,930	28,639	2.5
OCTOBER	26,822	26,125	-2.6
NOVEMBER	25,144	25,912	3.1
DECEMBER	25,919	26,091	0.7

TABLE 4

NET IMPORTS INTO CALIFORNIA[60] (AVERAGE MW/HOUR)

MONTH	1999	2000	DIFFERENCE
May	6,127	4,481	-1,647
June	5,740	3,367	-2,373
July	6,551	2,183	-3,738
August	6,358	1,578	-4,779
September	6,814	2,962	-3,852
October	5,641	4,621	-1,020
November	6,741	4,040	-2,702
December	7,680	3,211	-4,469

[60] Based on Hour-head import schedules reported by the California ISO as provided on the University of California Energy Institute's web site.

TABLE 5

AVERAGE LOAD IN THE CAISO AREA
(MW/HR)

1. Actual Average Load

MONTH	2000	2001	% CHANGE
January	25,516	25,229	-1.1%
February	25,585	24,558	-4.0%
March	25,523	24,001	-6.0%
April	25,329	23,974	-5.3%
May	26,883	26,427	-1.7%
June	29,981	27,378	-8.7%

2. Weather Adjusted Load

MONTH	2000	2001	
January	25,324	25,436	-1.0%
February	25,559	24,547	-4.0%
March	25,501	24,017	-5.8%
April	25,222	23,881	-5.3%
May	26,247	25,049	-4.6%
June	28,751	26,333	-8.4%