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The California Electricity Experience, 2000-01: *Education or Diversion?*

TIMOTHY J. BRENNAN



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The California
Electricity Experience,
2000-01:
Education or Diversion?

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The author is a senior fellow at RFF and a professor of policy sciences and economics at the University of Maryland, Baltimore County (email: brennan@rff.org). Errors remain the responsibility of the author.

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CHAPTER ONE

Introduction

INDUSTRY DEREGULATION, like flying airplanes, makes the headlines only when there has been a crash. Opening electricity markets, formerly a topic of interest to only a few aficionados, has become one of the major stories of the past 16 months, thanks to the California experience. Ideally, the problems with high prices, rolling blackouts, bankrupted utilities, state bailouts, and allegations of anticompetitive conduct would be educational, providing lessons that other states could use to realize the promise that opening electricity markets might bring. The fear is that a bungled experience, at least viewed in hindsight, might divert us from difficulties in opening electricity markets that might befall even the best implementation of open competition.

We begin first with some general industry background. Three key factors about electricity—its crucial role in the economy, its vulnerability to even momentary imbalances between production and consumption, and the interrelatedness of all generators and users—make electricity a distinctive if not unique commodity. As we discuss at the end of the report, these factors can limit the amenability of electricity to allocation via markets. Variation in both the technologies and institutional forms used in the production and distribution of electricity is also extensive, and probably unmatched in the economy.

In the next section, we discuss why only the generation side of the electricity business is being opened to competition, that is, why the “wires” sectors in the industry—long-distance transmission and local distribution—will be regulated for the foreseeable future. After reviewing the potential benefits that would follow from competition in open markets, we summarize the policy developments that led to the opening of electricity markets at both wholesale and retail levels.

We then turn to the California situation, beginning with some basic information about the size and structure of the California electricity market. The complex implementation of retail electricity competition in California began in 1996, and retail markets opened in the spring of 1998. A key fact is that this process worked reasonably well in California, at least with regard to the pricing and availability of electricity, until about June 2000—more than two years. We present what has happened in California since, and then summarize the state’s (ever-changing) set of responses to the power crisis.

The focus of this report is a review of the situation in California. There are enough potential culprits to compose a “Top 10” list:

1. Supply-and-demand imbalances
2. Higher fuel costs
3. Supply-reducing regulations
4. Wholesale price regulation (actual or threatened)
5. Retail price controls
6. Inframarginal rent transfer
7. Absence of real-time metering
8. Bad luck—lack of long-term contracts
9. Auction design
10. Market power

We examine each of these in some detail, particularly the entries toward the bottom of the list. We also take a brief look at additional, more general problems with electricity competition—other pricing and implementation problems, “social” regulations, and distributional politics—and then conclude with a brief look at policies that other states might adopt to reduce the risk of repeating the California experience. That experience may divert us from the deeper question of whether the crucial, vulnerable, and inter-related nature of the electricity system prevent reconciling meaningful competition with the central control and cooperation necessary to maintain system reliability.

■ ■ ■

CHAPTER TWO

Background

What Makes Electricity Unique?

Understanding the difficulty in restructuring the industry, the California troubles, and whether the record so far adequately conveys what the future may bring requires a sense of why electricity is an unusual commodity not only among those deregulated but also among all the commodities in the economy as a whole. Electricity's special nature arises from the combination of three features: electricity is crucial, vulnerable, and interrelated. No one of those factors is necessarily unique to electricity, but the combination makes for a particularly troublesome mix.

The first consequential property of electricity is that it is crucial to the economy. Roughly 2–3% of the nation's gross domestic product is spent on electricity, a figure comparable to what we spend on telecommunications, chemicals, or agriculture.¹ As with those commodities, the revenue percentage vastly understates the consequence to the economy if supplies of electricity were to fall by any significant amount.² A favorite illustration is that the term we use for the growth of digital telecommunications and Internet-related business is not “computer commerce” or “digital commerce” but “electronic commerce.”

Electricity is not alone in being a crucial part of any minimally developed economy. More unusual, particularly among such commodities, is vulnerability from an even momentary inequality of production and consumption. If electricity supplies exceed use at any given time, the system can break down from power overload. If demand exceeds supply at any one time, brownouts and blackouts can occur. Inability to economically inventory and store electricity means that matching electricity use to electricity availability, called *load balancing*, requires that production continually match consumption.

Most commodities are not vulnerable to such imbalances. For many, if supply is less than demand at any particular instant—the telephone line is busy, the bus is crowded, a favorite brand of cereal is not on the shelf—consumers can easily wait or shop around for an alternative. Other commodities can be stored if supplies are expected to be tight. If demand falls short, sellers can hold items in inventory to sell them at a later time. This is not to say that costs related to supply-and-demand inequalities, storage, and inventories are trivial in other industries. However, they are sufficiently prohibitive in electricity that what in most industries is an annoyance can become a disaster. Accordingly, the market's usual degree of accuracy in matching consumption to production may not suffice in electricity.

Were electricity only crucial and vulnerable, producers and consumers could ensure through their own dealings and contracts that electricity was available as needed. But this is where the third property of electricity, interrelatedness, comes into play. If a given supplier fails to produce enough electricity to meet the demand of its customers, its customers will not be the only parties left without power. Unless some other generator serendipitously is producing too much power, all customers on the relevant distribution or transmission grid may be blacked out. The costs of error are not internal to specific buyers and sellers; they fall on the market as a whole. Consequently, some centrally produced incentives or explicit system control is necessary to ensure that one supplier's imbalance does not bring down the entire system.

Other Industry Characteristics

Electricity has some other characteristics that complicate the management of restructuring. One is the variety in generation technologies. Electricity is produced using steam generators fired by coal, natural gas, oil, or nuclear power. Gravitational power, harnessed through hydroelectric plants, is significant in areas of the country where sufficiently large rivers are available. Renewable³ fuels, such as wind, biomass, and geothermal technologies, are a small but growing part of the electricity portfolio. One would be hard pressed to find another industry of consequence in which such radically different technologies are used simultaneously.

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One reason for this variety in production technologies is geographic. Some generators are near coal mines and railroads, while others are near gas pipelines. Hydroelectric power requires large amounts of running water; wind power requires open spaces with the right climate. Other differences are driven by differences in the energy product itself. As noted above, electricity has to be produced continuously to meet consumption levels. Some plants can and should always be on to provide the “baseload” amount of electricity used more or less all the time. Other plants need to come on during foreseeable “peak” periods; some variation is seasonal (for example, demand for air conditioning in summer), and some is related to the time of day (for example, business hours versus late at night). Yet other plants need to be available, with different

degrees of notice, to adjust supply incrementally or to come on line quickly in case of unexpected surges in demand or plant failure. Some technologies can be brought into service more quickly than others to meet unexpected needs.

Different generation technologies are more amenable to one part of this demand. Plants with high fixed costs and low operating costs tend to be more useful for meeting baseload demand, whereas plants with lower capital cost-to-operation ratios are better suited to meeting peak demand.⁴ A plant designed to power air conditioners during the hottest 80 hours of the year has to recover its capital cost in just 1% of the hours of the year, a hundred times more quickly than a baseload plant.

An increasingly important factor in determining the breadth of technologies in electricity generation involves pollution regulation. Any plant that burns fossil fuel emits carbon dioxide (CO₂), a currently unregulated but important contributor to global warming. These plants also

may produce significant amounts of nitrogen oxide compounds (NO_x). Coal plants, particularly those that use high-sulfur coal, emit significant amounts of sulfur dioxide (SO₂).⁵ Nuclear plants produce none of these emissions, but they come with concerns regarding the disposal of spent radioactive fuel and the fate of the plants themselves, which become radioactive with use. Hydroelectric power, nominally clean, creates concerns regarding fish spawning routes and flooding of land behind dams. Decisions on whether to regulate these environmental problems, as well as the methods for and stringency of such regulations, may affect the mix of technologies used to generate electricity.

Accompanying this variety in generation technology is a variety of organizational forms. Before efforts to open power markets, the electricity industry was composed primarily of investor-owned utilities (IOUs), vertically integrated through the production chain from electricity generation through long-distance transmission to final distribution and sale. Roughly three-quarters of the electricity in the United States was supplied by IOUs. The remainder was mostly distributed to end-users by distribution systems owned by government entities (referred to as public power, municipally owned systems, or “munis”) or on a cooperative basis by the customers themselves. Public power companies and co-ops—especially the latter—are primarily but not exclusively found in rural areas; notable exceptions include the Los Angeles Department of Power and Water and the Sacramento Municipal Utility District system in California. Public power systems may produce their own electricity or obtain it from other sources. They have priority over obtaining power from federally owned electricity producers, the largest of which are the Tennessee Valley Authority and the Bonneville Power Authority in the Pacific Northwest.

Regulated Monopoly and Unregulated Competitors: The Boundary Problem

Another complication regarding the electricity industry that affects the deregulation effort is that only the generation and marketing sectors are ripe for deregulation. In both of those sectors, scale economies appear sufficiently small relative to the size of the market to allow multiple vendors to compete.⁶ The same cannot be said of the wires sectors, that is, local distribution and long-distance transmission. Local distribution is a monopoly service largely because one set of lines, poles, and conduits is sufficient to supply the electricity that consumers are likely to demand. It would be wasteful for another provider to install its own distribution grid over the existing one.

Transmission is also a monopoly, but for a more complex reason. Were it simply a matter of scale economies, we could have the degree of competition in long-distance electricity transmission that we have in long-distance telephone service. But long-distance electricity transmission differs in two ways. First, transmission lines are interconnected, so that power can be sent in either direction depending on which regions have extra capacity available and which regions need more electricity. Second, it is excessively costly to “route” electricity onto selected interconnected lines rather than all of them. Interconnection plus the inability to route electricity—the “loop flow” or “parallel flow” problem—means that power going from Generator A to Distribution B travels on every possible open transmission path between the two points. Despite the appearance of separately owned lines, the transmission grid is, functionally, a single economic unit. One utility’s ability to transmit electricity depends on the capacity of lines owned by others.

Until “distributed generation”—that is, the ability of consumers to meet their power needs by producing electricity on their premises—becomes more economical, local distribution and long-distance transmission are likely to be regulated for the foreseeable future.⁷ The electricity industry, then, will be only partially deregulated. Partial deregulation in an industry creates special problems in managing the relationship between the regulated and unregulated sectors, particularly if utilities remain vertically integrated across the boundary.⁸ A first concern is *cross-subsidization*, that is, that the firm will shift costs of its unregulated service onto its regulated operation, raising regulated rates and creating an artificial competitive advantage in its competitive markets. A second concern is *discrimination*, in which the firm gives its competitors in the unregulated markets delayed or inferior access to its regulated service. In electricity, discrimination could appear as a transmission grid owner providing better and more timely line capacity to its own generators than it gives to generators owned by its competitors. The result can be monopolization of the nominally unregulated market, in which the firm captures from consumers the profits that regulation of its natural monopoly market was intended to suppress.

Benefits of Retail Choice

The crisis in California necessitates a reminder of why one might have thought introducing competition into the production and marketing of electricity would be a good thing. Some of the advantages are the benefits that competition brings to any market. Competition pressure among power suppliers, in the first instance, should lead to lower prices overall for electricity.⁹ The pressure would come from competition among incumbents, and new entrants able to construct generators using the most advanced technologies would only increase the expectation of lower prices. Such savings were forecasted; for example, the U.S. Department of Energy estimated savings of about \$20 billion, or about 10% of the nation’s electricity bill, from competition.¹⁰ These predicted savings affected the willingness of individual states to open markets in that those states with higher electricity rates (for example, California and New York) tended to open electricity markets earlier than others.¹¹

A second advantage of opening electricity markets to competition is that it may reduce distortions in pricing and allocation created by the regulatory system. One possible example is the apparently favorable treatment given to industrial buyers over residential buyers. Through the late 1990s, industrial customers purchased electricity at a substantial discount relative to residential users. The price differential in 1999, for example, was almost 50%.¹² Some of this price differential may reflect real cost savings for industrial customers arising from user-specific economies of scale, proximity to high-voltage transmission lines, and a willingness to tolerate power interruptions. Another explanation is that some industrial users might have chosen to generate their own electricity if they did not receive sufficient discounts.

This differential may also arise from bargaining clout that large purchasers may have. This clout may not be merely what we see in normal markets but may reflect large industrial users’ political wherewithal in a regulatory system. Part of that political advantage may reflect the ability well-organized entities have over dispersed consumers in influencing regulators to act on their behalf.¹³ Many of these large actors may also have a specific political threat—to move offices and production facilities from their current home state to another if the home state’s public utility commission does not give them favorable treatment. Opening electricity markets to

competition would allow new marketing entrants to aggregate the purchases of a large number of consumers in such a way as to match some of the bargaining advantages held by industrial users. Aggregation is common in the economy, as a chain of grocery stores combines the purchases of thousands of individual households into an entity that can bargain effectively with food suppliers.

A final advantage to opening retail markets is that it allows innovative options in the purchasing and delivery of electricity. One notable example is the ability of suppliers of power generated in particular ways to sell to consumers willing to pay a premium to avoid contributing to the undesirable environmental effects discussed above.¹⁴ A second example is that with open markets, electricity providers can bundle power with capital equipment for heating, air conditioning, and lighting systems to provide a total package of energy management services. Through these packages, energy companies can best exploit the potential for reducing the cost of providing energy services, be it through less expensive generation or investment in more energy-efficient devices. Competition among suppliers of these services would, in principle, transfer the savings to consumers through pressure among suppliers to offer these services at cost-based prices. In particular, consumers would gain even if they did not have a clear idea about how the benefits in reduced electricity expenditures would offset the cost of high-efficiency equipment.¹⁵

*Policy History*¹⁶

For most of its history, the electricity industry has been regulated by state and federal governments. The traditional dividing line between federal and state jurisdiction is that the former controls the “wholesale” side of the electricity industry and the latter controls the “retail” side. *Wholesale* generally refers to the production, delivery, and sale of electricity to the distribution utilities, whereas *retail* refers to the prices that residential, commercial, and industrial customers actually pay for power. Because most utilities were vertically integrated from generation through transmission to distribution and sale to final users, the practical consequence of this distinction was that for the most part, state public utility commissions played the dominant role in setting electricity rates.¹⁷

The story became more complicated as the federal government took actions to open the wholesale market to nonutility independent power producers. This opening began in 1978 with passage of the Public Utility Regulatory Policies Act (PURPA). In response to concerns regarding energy supplies in the 1970s, precipitated by the growing environmental movement and oil price shocks driven by the Organization of Petroleum-Exporting Countries (and exacerbated by regulations), PURPA required utilities to transmit power from so-called qualifying facilities (QFs). QFs were primarily facilities that produced power using renewable fuels or industrial “co-generators” that produced electricity onsite and could, at least at times, supply electricity into the market itself. PURPA also empowered states to force utilities to purchase power from QFs

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at the “avoided cost” of additional utility generators, where states could determine how high the avoided cost was and, thus, how much “outside” power utilities would have to buy.

PURPA’s effects were not entirely benign. Its implementation in many states led utilities to sign long-term contracts with renewable power providers at prices considerably in excess of the cost of generating power from conventional facilities. But PURPA did have a perhaps unintended but significant consequence: it showed that wholesale electricity markets could function if non-utility generators had appropriate access to utility-owned transmission facilities, so they could get their power to buyers.¹⁸ In 1992, Congress passed the Energy Policy Act to extend PURPA’s open-access policies to all generators, not only PURPA-defined qualifying facilities. The result of that process was the Federal Energy Regulatory Commission (FERC) Order 888, issued in summer 1996, which essentially created wholesale power competition throughout the United States.¹⁹

In addition to ordering utilities to open their transmission grids to unaffiliated generators, Order 888 requires that the utilities “functionally unbundle” their generation and transmission businesses, to prevent anticompetitive favoritism in granting access to affiliated electricity producers.²⁰ The form of such unbundling is not specified. It may include anything from separate books of account to outright divestiture. The preferred form of organization has been the independent system operator (ISO), in which utilities would continue to own transmission facilities but cede operational authority to an independent board. Order 888 includes desirable rules for ISOs. FERC retains authority to approve or disapprove the specific procedures ISOs choose, but it does not mandate ISOs. Regarding the development of ISOs as being insufficiently rapid and broad, FERC issued its Order 2000 concerning regional transmission organizations (RTOs), a variation on the ISO theme.²¹ Each utility that owns an interstate transmission facility was required to propose or participate in an RTO, or explain why it would do neither, by Jan. 15, 2001. In July 2001, FERC expressed an intention to collect the transmission facilities in the United States into four RTOs covering the entire nation, reflecting the regional nature of wholesale electricity markets.²²

FERC’s initiatives in the past five years speak only to wholesale markets, in which generation companies compete in the sale of electricity to firms that resell to final customers. The decisions whether, when, and how to extend competition to electricity sales to those final consumers—that is, to let households, businesses, and factories choose their power suppliers—fall to those with authority over retail electricity markets: namely, the states. So far, about 25 states (shown in black or dark gray in Figure 1) have passed legislation or issued regulatory orders that will open electricity markets to competition. Some of these states are reportedly rethinking their decisions in light of the crisis in California.

The federal government has considered weighing in on this issue. Some of the concerns have been about the potential effect of restructuring on the environment. As more generators enter and the areas in which incumbent generators can sell their power become more widespread, the mix of fuels used to create electricity may change, with different effects on the volume and location of emissions.²⁴ In addition, the predicted fall in electricity prices would lead to more electricity use, which would increase emissions, holding the generation mix constant.²⁵

A greater concern, however, has simply been whether the federal government should push states into opening electricity markets. Some current laws might impede competition or make little sense in a competitive environment, and thus should be modified or repealed. The Clin-

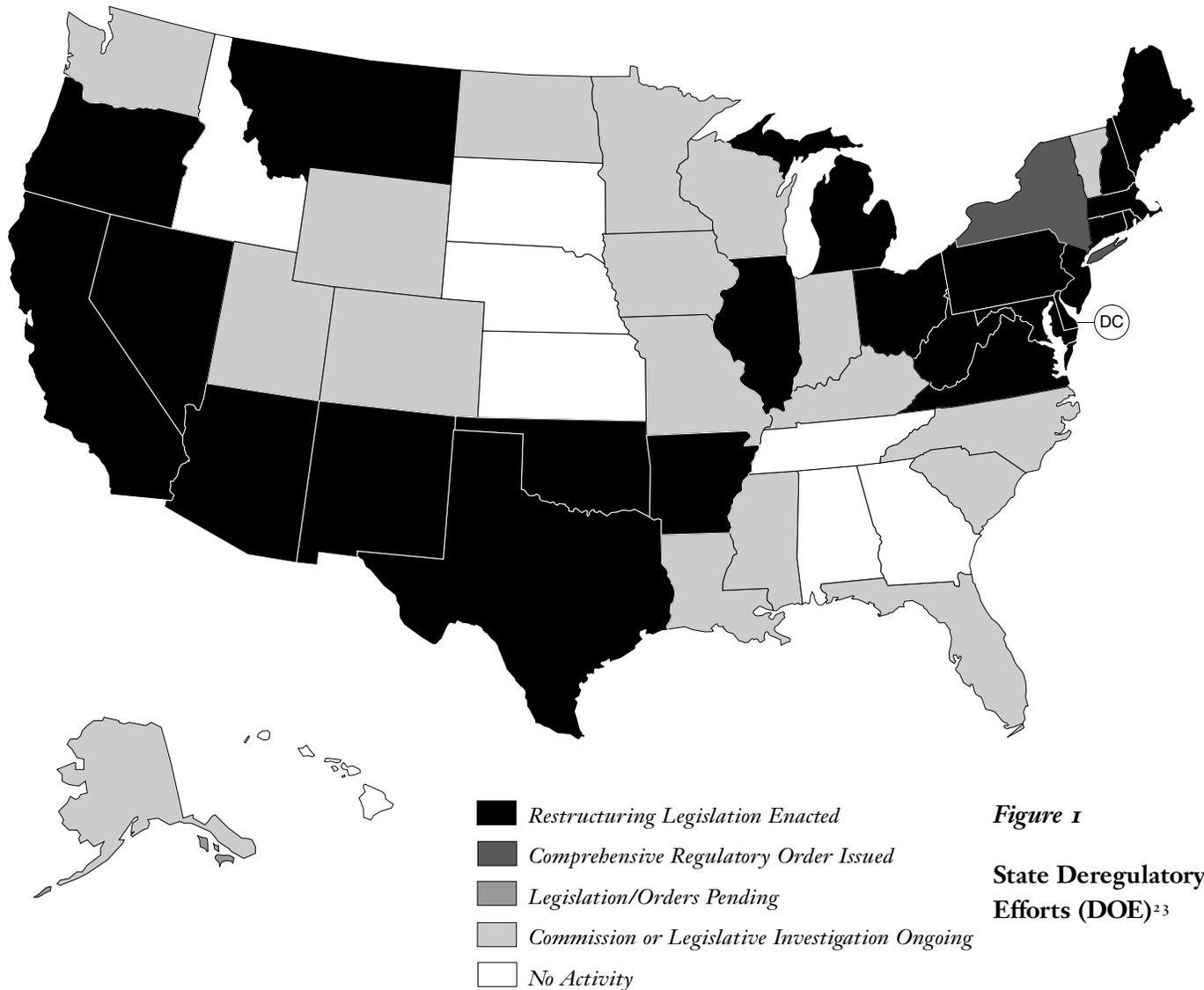


Figure 1
State Deregulatory Efforts (DOE)²³

ton administration's Comprehensive Electricity Competition Plan would have forced states to either open electricity markets by January 2003 or formally opt out through some sort of public proceeding.²⁶

The United States is not the first country in which electricity competition is being attempted. Important initiatives have taken place in several other countries, including Chile, Finland, Germany, Sweden, and the United Kingdom. In many of these countries, opening markets has brought the expected results, namely, falling power prices.²⁷ In the United Kingdom, however, prices are roughly 20% higher than before the markets were opened.²⁸ The European Commission is proposing that all consumers in the European Union be able to choose their power supplier by 2005.²⁹

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CHAPTER THREE

California

Background

Befitting its size, California is a large electricity market. According to U.S. Department of Energy data for 1999, California retail electricity sales totaled about \$22.8 billion, about 10% of the U.S. market.³⁰ Although California is a large market, it uses less electricity per capita annually than the rest of the country—7.4 megawatt-hours (MWh), compared with a U.S. average of about 12.4 MWh.³¹ In 1998, on a per capita basis, California was 49th among the states in generation capacity and 50th in actual power generated.³² About 18% of the power used in California in 1999 was imported.³³

In 1999, the price of electricity in California averaged about 8.8¢ per kilowatt-hour (kWh), compared to about 6.6¢/kWh nationally.³⁴ Just over half of the electricity in California is generated by natural gas or oil plants, and another quarter comes from hydroelectric power. Nuclear plants supply about 8% of the electricity, and wind and geothermal sources provide another 8%. Unlike in most of the rest of the United States, virtually none of the electricity in California is generated by coal.³⁵

A patchwork of investor-owned utilities and public power systems provide electricity in California.³⁶ Most is supplied by three major IOUs. Pacific Gas and Electric (PG&E) supplies most of northern California, roughly points north of Santa Barbara and Bakersfield. San Diego Gas and Electric (SDG&E) serves the San Diego metropolitan area. Southern California Edison (SCE) serves most of the southern part of the state, excluding greater Los Angeles, which is served by the Los Angeles Department of Water and Power, a public power provider. Also, as mentioned above, Sacramento gets its electricity from its public power provider, the Sacramento Municipal Utility District.

Deregulation History

After a series of feasibility studies in the mid-1990s, the California state legislature unanimously³⁷ passed and then-Governor Pete Wilson signed Assembly Bill (AB) 1890, directing the California Public Utility Commission (CPUC) to “authoriz[e] direct transactions between electricity suppliers and end use customers,” that is, to open entry into retail markets. The bill required CPUC to set up an ISO to manage the California transmission system and procure power

as needed to maintain load balances in real time. The legislation also mandated an independent Power Exchange (PX) in which most power would be traded. The PX traded power in three major ways: one day ahead of use, one hour ahead of use, and in longer-term “block forward” contracts. To ensure that incumbent utilities recovered the potentially “stranded costs” associated with prior investments and long-term electricity purchase contracts, the legislation required a nonbypassable transition charge, which later came to be called the “Competitive Transition Charge” (CTC).

The legislation specified that retail markets would be fully open by Jan. 1, 1998; the actual opening took place by March of that year. For the first four years, the incumbent IOUs (PG&E, SCE, and SDG&E) were required to buy power from the PX, rather than through independently negotiated bilateral contracts.³⁸ Retail rates were reduced by 10%, and the reduction was to be maintained until the IOUs recovered their stranded costs through CTC collections. To improve the prospects for competition, the IOUs also were required by the state to divest some of their power plants. By 1999, the IOUs had reduced their share of California’s generation capacity from 81% to 46%.³⁹ SDG&E divested almost all of its capacity; by June 1999, it had recovered all of its stranded costs and thus was allowed to charge market-based rates.⁴⁰

Since June 2000: What Happened?

Throughout California, because the IOUs were forced to cut prices, and because customers of new entrants had to pay the CTC charge, there was perhaps less entry at the retail level than expected. As of January 1999, only about 1% of residential customers had switched providers, although 18% of industrial customers, which made up 28% of industrial sales, had switched.⁴¹ At least from the standpoint of prices and reliability, restructuring in California seemed to work reasonably well for more than two years. Figure 2 indicates that, until June 2000, electricity prices in California remained fairly low. Wholesale prices ranged roughly between 1¢ and 3.5¢/kWh off-peak, and peak prices were roughly a penny higher.

A similar sense of the performance of the market can be gleaned from looking at the number of occasions in which reserves were declared to be precariously low, referred to by the California ISO as “staged emergencies.”⁴³ Figure 3 shows that before summer 2000, such emergencies were virtually nonexistent; they occurred only during summer months, and three occurred, at most, in any one month. At no time during that period did blackouts related to systemic imbalances occur.

Consequently, any hypotheses regarding the causes of the California crisis have to account for the fact that, for more than two years, and in all seasons, the system worked reasonably well.⁴⁵

As Figures 2 and 3 show, the turn for the worse began around June 2000. Both peak and off-peak wholesale prices began to spike up to levels nearly 10 times those reached during the previous two years. Alerts became much more frequent, with increasing power interruptions and some rolling blackouts in northern California. Because SDG&E’s retail rates had been deregulated, these wholesale prices led to reports of up to a tripling of retail electric bills, leading to reregulation of SDG&E’s rates in September 2000, retroactive to the previous June.

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Figure 2

California Wholesale Electricity Prices

April 1998 through October 2000⁴²

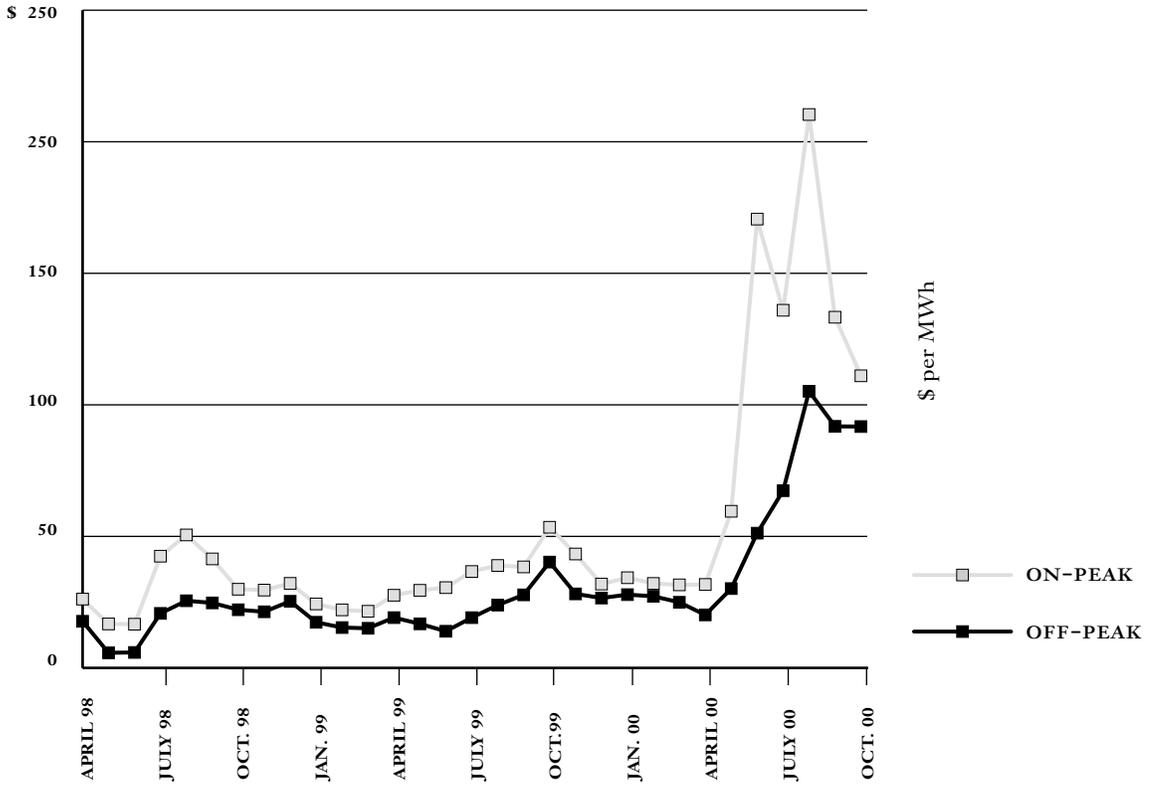
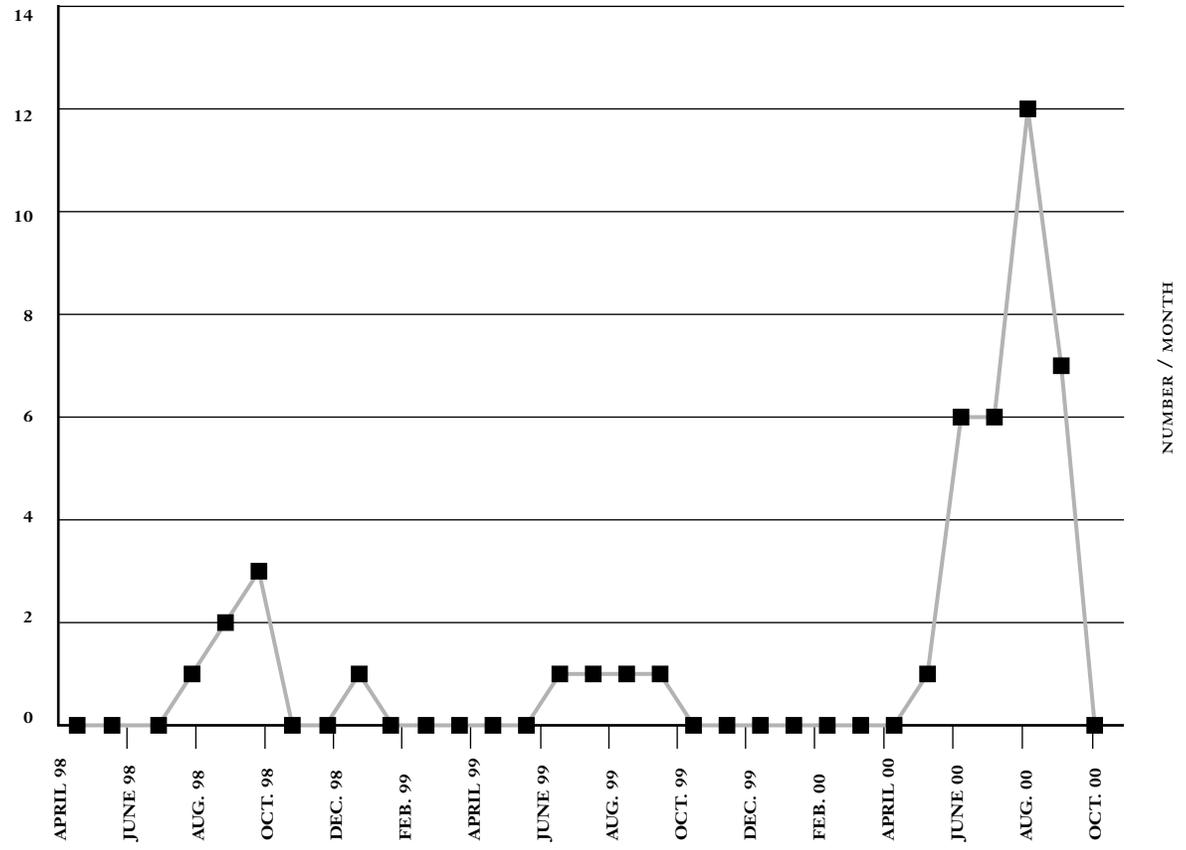


Figure 3

Staged Emergencies in California

April 1998 through October 2000⁴⁴



While wholesale electricity prices ballooned, retail price ceilings on the IOUs left the utilities unable to cover their expenses. As the utilities teetered closer to bankruptcy, power producers became less willing to sell them electricity. Prices in winter 2001 continued at levels about 10 times the 1999 average, despite winter being a typically off-peak season for electricity demand in California.⁴⁶ Citing a FERC order forcing it to “implement a \$150 breakpoint” that, apparently, was below the price generators were willing to offer power, the California PX suspended operation on Jan. 31, 2001.⁴⁷ Within two weeks, a federal district judge forced generators to continue to sell power to the utilities, despite the utilities’ failure to maintain an “approved credit rating.” The court cited “emergency dispatch” provisions in the ISO’s rules and the severe harm if generators refused to provide power in California.⁴⁸

California and FERC Responses

As the financial status of the distribution utilities worsened, the state government reluctantly began to act, mostly by expanding its direct role in the industry. The legislature authorized the state to purchase power, finance plant construction and retrofitting, fund conservation programs, and sell power directly to retail customers.⁴⁹ The governor further proposed that the state would apply cost-plus regulation to power supplied by plants the utilities kept.⁵⁰ Consumers who purchase from these utilities would be locked in. This proposal has led to the exit of alternative energy suppliers who had hoped to lure customers away from the incumbent suppliers.⁵¹

Partly to relieve utility debt, California Governor Gray Davis commenced negotiating deals to purchase the transmission lines owned by the utilities, including a deal to purchase SCE’s grid for \$2.76 billion—2.3 times its book value.⁵² Under the arrangement, the state would undertake taxpayer-funded expansions of the transmission lines to increase power availability in northern California.⁵³ The governor also has considered using profits earned during the crisis by the utilities’ retained generators (estimated at \$3 billion to \$4 billion) to cover some of the debts that utilities have incurred on the distribution side.⁵⁴

The story continued to break as this report was written. To alleviate some of the pressure on the market created by caps on NO_x emissions created under its RECLAIM program, California’s South Coast Air Quality Management District (SCAQMD) lifted quantity limits on emissions, allowing generators to emit NO_x at a price of \$7.50 per pound, around five times historical levels but about one-fifth the price to which they had risen during the crisis.⁵⁵ Courts continued to extend orders to generators to continue to sell to utilities.⁵⁶ FERC reviewed wholesale power prices for excesses due to market power and, based on a proxy market price of \$273/MWh, ordered \$69 million in refunds for overcharges that occurred in January 2001 during emergency conditions.⁵⁷ However, the California ISO provided studies that estimated an overcharge during that month of \$1.364 billion, almost 20 times FERC’s estimate.⁵⁸ CPUC decided that to cover the cost of electricity, it would bite the bullet and raise power rates by 40%.⁵⁹ For PG&E, these responses may have been too little, too late; it filed for Chapter 11 bankruptcy protection on April 6, 2001.

Subsequently, in April 2001, FERC issued an order requiring power producers to bid in available power to the ISO, and capped wholesale electricity prices in California during periods when unused reserve capacity for electricity generation fell below 7.5% of the power produced.⁶⁰ Generators could get waivers to sell power at prices above the cap with appropriate justification.⁶¹

About two months later, FERC expanded this policy to set caps on wholesale power at all times, and throughout the western United States rather than just California.⁶² During times when reserves were low, the cap would be based on the cost of the most expensive gas-fired generator; at other times, the cap would be 85% of the price set during the most recent period of low reserves.⁶³ The price caps are scheduled to remain in place until September 2002.⁶⁴

While FERC was taking a stronger role in the market, it continued to be embroiled in the dispute regarding the size of refunds due California. Under the auspices of FERC's Chief Administrative Law Judge, settlement talks between California and the generators took place in June and July 2001.⁶⁵ The talks proved unsuccessful.⁶⁶ California took the position that it was owed \$8.9 billion, while the leading generation proposed in the aggregate about \$700 million.⁶⁷ The Chief Judge noted in his July 12, 2001, settlement report that "while there are vast sums due for overcharges, there are even larger amounts owed to energy sellers by the CAISO, the investor-owned utilities, and the state of California."⁶⁸

As summer 2001 began, reliability experts forecast that California might suffer as much as 260 hours of rolling blackouts.⁶⁹ Those dire predictions were not borne out, as California got through the summer without a power outage,⁷⁰ with August prices falling to \$53 per megawatt-hour, about a third to a quarter of levels the preceding year.⁷¹ Just as the blackouts themselves were likely the result of numerous factors, described below, the ability of the state to avoid serious problems this summer was also attributed to a variety of causes. Some of the credit goes to an unusually effective conservation campaign, reducing electricity consumption in California by over 12% compared to the previous summer, according to the National Resources Defense Council.⁷² However, another major contributor was a summer that was milder than expected.⁷³ Nevertheless, the state continued to walk away from its deregulation efforts. On Sept. 20, 2001, the California Public Utility Commission voted to end giving electricity consumers the ability to choose their electricity suppliers.⁷⁴

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CHAPTER FOUR

Potential California Culprits: A “Top 10” List

THE SEVERITY OF THE CALIFORNIA CRISIS has brought forth no small number of possible explanations. We can identify 10 such potential culprits, as listed below.

1. *Supply-and-demand imbalances*: The capacity to produce and deliver electricity to users in California failed to keep up with growth in demand.
2. *Higher fuel costs*: Prices for power rose because the fuels used to produce it, particularly natural gas, became more expensive.
3. *Supply-reducing regulations*: Rules restricting the construction of generation facilities and emissions of particular pollutants reduced electricity supplies and raised generation costs.
4. *Wholesale price regulation (actual or threatened)*: Limiting or threatening to cap the prices a generator could charge for power sold to the distribution utilities can discourage supply.
5. *Retail price controls*: Holding down retail prices kept demand high during peak periods and caused distribution utilities to lose money when they had to purchase wholesale power at high prices.
6. *Inframarginal rent transfer*: Moving from regulation to competition implied that when prices began to rise to cover the cost of the “marginal” firm, all of the suppliers were able to charge that high price, redistributing wealth from consumers to producers.
7. *Absence of real-time metering*: The general absence of devices to measure power use at any given time prohibited setting power prices high during peak-use periods, removing an important incentive to conserve power and reschedule uses for times when electricity is more plentiful.
8. *Bad luck—lack of long-term contracts*: Rules requiring distribution utilities to buy power from the PX kept them from insuring against high wholesale prices via long-term contracts.
9. *Auction design*: Instituting an auction in which suppliers could get the highest accepted bid price could have created incentives to “game” the system.

10. Market power: Through collective action or unilateral conduct, generators may have charged prices substantially above the competitive level.

Each of these possible culprits probably contributed to the difficulties in California. Some of them are, in economic terms, “substitutes,” in that if one had not been present, others might have had the same effect. Inability to charge prices in real time because of the inability to measure demand in real time might not matter as long as regulators capped retail prices during peak periods. Other causes may be “complements,” in that the presence of one of them may have exacerbated the problems created by another. A lack of long-term contracts for power could have worsened the transfer of money from consumers to producers when prices went up during peak periods. Some of the causes may work at cross-purposes. If long-term contracts had kept power prices down, then consumers would have been less likely to see prices that would have encouraged them to cut demand during periods when electricity was particularly expensive.

In the next chapter, we review some of the facts and issues regarding these possible explanations. In assessing them, note that restructuring in California worked well for more than two years and is working reasonably well in other parts of the country and throughout the world. Any explanation that insists opening electricity markets to competition necessarily leads to a California-like crisis is intrinsically suspect. Opening those markets may be a necessary condition for some—not all—of these potential explanations, but it is not sufficient.

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CHAPTER FIVE

The Basics: Supply, Demand, and Regulation

Supply and Demand

The first three items on the top-10 list (supply-and-demand imbalances, higher fuel costs, and supply-reducing regulations) affected the overall supply-and-demand balance in California. They are important because they have little if anything to do with restructuring per se. If they contributed to the high prices, tight supplies, alerts, and rolling blackouts in California, they would have contributed similarly even if the electricity markets in California were still regulated. The other items on the list, of course, could and likely did aggravate the effects from these supply-and-demand factors.

General Supply and Demand Imbalance

According to the U.S. Department of Energy, during the 1990s, demand for electricity in California grew by 11.3% and capacity to generate electricity in that state fell by 1.7%.⁷⁵ In recent years, thanks to economic expansion and population growth, electricity demand growth accelerated to more than 3% per year.⁷⁶ Demand also has grown in other areas of the western United States that supply electricity into California, which is a net importer of electricity. The supply crunch was exacerbated by a lack of rainfall in the western United States, reducing hydroelectric power supplies in summer 2000 by 28% below production in 1999.⁷⁷ Along with generation constraints, limits on transmission have hampered the delivery of electricity into and within California to areas most in need.⁷⁸ The combination of net capacity reductions and demand growth with the other attributes of electricity—very inelastic demand (abetted by rules and impediments to flexible retail pricing) and inability to store electricity for use in times of shortage—is a sure recipe for significant increases in wholesale electricity prices and blackouts.

Higher Fuel Costs

Exacerbating the supply-and-demand problem were higher fuel costs. In California, natural gas plants are generally the marginal power plants. If the cost of natural gas increases, the cost of meeting marginal power demand increases, raising the price necessary to attract enough electricity to meet demand. According to FERC, natural gas prices nearly tripled in the western United States during 2000.⁷⁹

Supply-Reducing Regulations

An additional factor possibly adding to a supply-and-demand imbalance was environmental regulation. In southern California, SCAQMD (the regional smog-control agency) operates the RECLAIM (Regional Clean Air Incentives Market) program, an emissions trading system for permits to emit NO_x and SO₂. As electricity prices rose in California, the price of NO_x permits

Environmental rules can and inherently should raise the price of commodities such as electricity when pollution is a by-product.

rose, indicating that the emissions constraint limited production to some extent. As noted above, among the responses to the California energy crisis was a change in the RECLAIM program to allow generators to buy an unlimited supply of permits at a price considerably below the prices to which they had risen during the summer.

One misunderstanding of the California situation involves these permits. Many commentators on the California energy situation attribute the increase in electricity prices to the increase in the price of the permits. This explanation confuses effect with cause. The increase in prices of the permits is a reflection of, not a contributor to, the increase in electricity prices. As electricity became more expensive, the demand for permits rose, allowing those who owned permits to earn scarcity rents. If the permit program mattered, it did so as a quantity constraint, not as an input price. The distinction is not only economic semantics. If the cause of high prices in California is something else (for example, the exercise of market power), it may be missed if analysts attribute the price increase to the increase in the price of NO_x permits.

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A longer-run environmental constraint on supply in California could be so-called NIMBY (“not in my backyard”) attitudes that impede power plant siting, approval, and construction.⁸⁰ The California Energy Commission, the state agency with the authority to approve construction of energy-related facilities, cites among the “critical issues” affecting siting “availability of emissions offsets, . . . local agency and public opposition, [and] land use constraints.”⁸¹ The Sierra Club denies that environmental regulations have had much effect on power plant construction.⁸² The important point is not to attribute blame. Environmental rules can and inherently should raise the price of commodities such as electricity when pollution is a by-product. Whether the price increase attributable to environmental regulations in California is above or below the value of the environmental benefits generated by those regulations is for the political institutions in that state to decide.

Price Regulation

The next two items on the top-10 list, wholesale price regulation (actual or threatened) and retail price controls, concern the ways in which price regulation may have caused or amplified the California crisis.

Wholesale Price Regulation

Under federal law, FERC has the authority to set limits on wholesale prices. During the California situation, FERC has considered such regulation, at the behest of numerous parties who would, understandably, like lower prices. So far, FERC has not instituted “hard” regulation but

did implement a “soft” price cap or “breakpoint” of \$150/MWh in December 2000. Under this plan, sellers who bid below this cap would get no more than \$150/MWh for wholesale sales in California. Those who bid above that amount would receive their actual bids but would be subject to investigation and potential refund.⁸³

Even though this breakpoint was about five times the usual price of power in California before the crisis, it could and perhaps did impede supplies. The unwillingness of generators to abide by that soft \$150 cap led to the closing of the California PX in late January 2001.⁸⁴ Supply reductions with a wholesale cap ought not be surprising. Peak electricity can be an expensive commodity to supply. Plants that meet peak needs have to cover capital costs in much less time than that available for a plant operating continuously.⁸⁵ If generators do not expect to recover these costs, they will not enter the market. When FERC calculated its refunds, it found that the appropriate marginal cost during peak periods was \$273/MWh, almost double this soft cap.⁸⁶

All this adds up to little more than the general proposition that in a competitive market, binding price caps reduce supplies and create shortages. There are two qualifications. First, if the wholesale power market is not competitive, then a price cap could increase supply. A cap below the noncompetitive price can dissuade suppliers from reducing output by reducing the potential profits associated with increasing prices above that cap. (We discuss some of the arguments associated with market power below.) A second qualification is that if the buyers in a market are liquidity-constrained and on the verge of bankruptcy, a price cap could reduce the buyers’ expenditures and keep them operating. Bankruptcy has been a very real consideration in this market, manifested concretely by PG&E’s April 6 filing for Chapter 11 protection, as we explain below.

Retail Price Controls

The primary reason for PG&E’s filing is the presence of retail price controls. With a competitive wholesale market and regulated charges for transmission and distribution, retail rates could have been deregulated. That they were not could have been the result of several factors. Optimistic expectations at the time AB 1890 was passed, supported by the first two years of the California electricity experience, might have encouraged regulators to think that the retail controls were not going to be binding. Such controls may have been viewed as protection against market power in the retailing stage of the industry, as long as the incumbent distribution utilities retained a near monopoly in that business. It was particularly likely as long as those who switched to competitors were required to pay a CTC that removed much of the ability of the competitors to underprice the incumbents. The retail price may have been held down below a price attractive to entrants as part of a political bargain, to redistribute some of the expected gains from restructuring back to consumers in the form of lower power prices.

Retail price controls contributed to the crisis in two ways. By setting a price ceiling, they prevented rates from going up during the peak summer demand season in 2000, thereby sustaining inelastic demands that overtaxed the system and drove up wholesale prices. However, the most significant effect of retail price controls was in conjunction with the steep increase in wholesale prices. In June 2000, when wholesale rates rose to five or more times their prior levels, the distribution utilities, forced to purchase power at those rates through the PX, started spending more money than they were taking in.

Capped retail rates, coupled with skyrocketing wholesale prices, appear to be the primary cause of the form the crisis has taken for most of 2001. The distribution utilities continued to

be obligated to serve retail customers but ran up huge debts. Those debts, in turn, called into question the utilities' ability to pay for wholesale electricity, leading to a vicious circle in which wholesalers would raise rates to cover the risk of nonpayment. Eventually, the bill came due, causing the largely political crisis of who was going to cover the losses. The burden seems to be spread among all of the obvious candidates—distribution company stockholders (bankruptcy), electricity customers (rate increases), California taxpayers (state-funded bailouts), and the generation companies (FERC-ordered refunds, court-mandated obligations to serve, and fractional debt repayment).

The combination of retail price controls with wholesale price flexibility seems the clear explanation for the crisis as it has evolved. However, it leaves open the question of why wholesale prices increased in June 2000.

Inframarginal Rent Transfer

Regulation may have led to and exacerbated the California situation. However, we ought not leave issues of the transition from regulation to competition without noting a potential political problem associated with a redistribution of wealth from consumers to generators, at least in the short run.

One virtue of opening previously regulated markets to competition is that it makes prices, and therefore costs, visible. Before Order 888, policymakers and electricity purchasers usually did not see explicit peak prices for wholesale power. One quite real possibility regarding the seemingly high wholesale prices observed occasionally after Order 888, outside California and before the recent crisis, is that we are only seeing a cost for peak power that was paid when the industry was regulated top-to-bottom.⁸⁷ As noted above, those costs could be substantial, especially to meet very short term demands for large amounts of power—such as air conditioning on unusually hot summer afternoons.

A reason that those peak costs were not visible in prior years is that these peak costs would have been averaged in with lower costs in off-peak periods. To be more precise, under traditional cost-of-service regulation, the additional revenues paid by users for peak power cover just the costs of the marginal plant. Markets operate differently. When prices are high, everyone in the market, not only the marginal firm, gets to charge the high price. A predictable consequence is that during peak periods, there will be a substantial transfer of wealth from consumers to producers, because all of the baseload producers get to earn inframarginal rents, charging peak prices considerably above their operating costs.

This outcome is efficient.⁸⁸ The marginal opportunity cost of a megawatt from the low-cost baseload plants equals the cost of replacing that megawatt from a high-cost, peak-load plant. But the transfer is likely to be politically upsetting, thus placing it on the list of potential contributors to the crisis. The initial symptom of the California crisis was not blackouts or bankruptcy but the political turmoil associated with higher retail rates in San Diego in summer 2000, during the three-month window in which SDG&E's rates were not regulated. Those higher rates may have been the manifestation of the transfer of wealth from consumers to low-cost generators.

This may be a relatively short-term problem. To the extent that the resistance to peak-load pricing is seasonal price volatility, retailers could offer consumers the opportunity to purchase electricity at annualized average rates, as insurance against high prices.⁸⁹ Retailers and genera-

tors would then bear costs associated with the risk. To deal with “moral hazard,” when consumers use more power at peak periods than they would otherwise thanks to the low rates, such contracts might include the equivalent of copayments (somewhat higher peak rates) and obligations to install energy-efficient appliances.

Contracts alone will not alleviate the wealth transfer. The only solution will be more entry. In a simple analogy, consider the case of hotels in a resort area, which cover their own operating costs during the off-peak season and recover their capital costs during the peak season. In the electricity market, new generators would enter if the expected profits (adjusted for risk) earned during the peak period would cover their capital costs. One would expect that off-peak power prices would be depressed, perhaps down to operating costs with little to no capital recovery. However, the political will to wait for entry may be insufficient, especially when both technology and regulation combine to make new generation construction a slow process.

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CHAPTER SIX

Market Design Idiosyncrasies

Absence of Real-Time Metering

As noted above in discussing retail regulation, a contributing factor to the California electricity crisis is that consumers have too little incentive to conserve power during peak periods because they do not see the correct price of electricity. If electricity costs \$300/MWh during peak periods, running a 3,000-watt clothes dryer for an hour will cost about \$0.90, whereas the cost would be only about \$0.09 during off-peak periods, when electricity costs \$30/MWh. Suppose turning up a thermostat a few degrees would reduce the use of a five-kilowatt air conditioner by two hours a day during peak-demand afternoons. A consumer who typically pays \$300/MWh during those hours would reduce his or her electric bill by about \$90 during that month but would save only \$9 at the off-peak (or average) price.

As long as consumers pay the same price for electricity regardless of when they use it, they will not reap these incentives from cutting back power use or, to put it perhaps negatively, pay the full price for power when they use it. Consequently, they will use too much power and have too little incentive to conserve. Some commentators have found the inability to charge real-time prices as the “fatal flaw” in California’s deregulation efforts.⁹⁰ Along with deregulating retail rates, a necessary step to getting users to see prices that reflect costs in real-time prices would be the widespread use of real-time meters, the absence of which is one of the possible contributors to the California crisis.

Assuming retail prices are not held constant by regulation, additional real-time metering would reduce demand for electricity during peak periods. One would not want policies that discourage real-time meters, for example, by regulating retail rates or discouraging retailers from entering into long-term contracts with generators and users that would reward those who agreed to accept real-time pricing. But the desirability of real-time metering need not imply policies to increase or mandate their use. Economic criteria warrant intervention in the market for real-time meters only if there are positive externalities associated with their installation. In other words, if one customer installs a real-time meter, or is paid to do so by the power supplier, does the meter generate benefits for others?

A first step in making this comparison is to look at the benefits of real-time meters, which would have to be weighed against the cost. Essentially, the benefits of real-time meters would be facilitating price flexibility, that is, allowing price to go to the level that equates supply and

demand, rather than remaining at a different fixed level (for example, the average price). They depend crucially on whether supplies meet demand at a price below what would be the market price, or whether the electricity has to be rationed across consumers, for example, through rolling blackouts.⁹¹

The benefits of installing real-time meters could be less than the cost. Such is likely elsewhere in the economy, for example, to explain why we see lines outside popular restaurants. If the benefits exceed the costs, the question is why markets supply too few real-time meters. Lest this question seem to have an obvious answer, one may ask whether the government should step in to encourage restaurants to offer “early-bird” discounts for dinners at 5:30 p.m., to cut down on the lines at 7:30 p.m. With regard to electricity, if the distribution utilities are obliged to serve customers, they have an incentive to pay people to use less power, for example, by installing real-time meters and agreeing to more efficient prices. Presumably, if the net gain from such a deal is positive, it should take place.

One possible answer is that the capacity for setting market-clearing prices in real time may be undersupplied when the underlying product (restaurant tables, electricity) is being rationed inefficiently. (*Inefficient rationing* means that some for whom the reservation price is low are getting the product, whereas others for whom the reservation price is high are going without.) When the quantity produced is inefficiently rationed, the market failure in not getting prices right is compounded by a misallocation of the goods supplied. The victims of the misallocation are not part of the bargain. If a low-valuing user and a generator cut a deal in which the former agrees to adopt real-time pricing, positive benefits will accrue to a high-valuing user able to get some electricity as a result.⁹² However, this externality will not hold when those with the highest reservation prices get the product, even when demand overall exceeds supply at the going prices.

A second related positive externality follows from the inter-relatedness of generators and customers on an electricity grid. Blackouts cannot be targeted on a consumer-by-consumer basis very easily. An individual consumer cannot easily buy his way out of avoiding blackouts by agreeing to pay a high peak price in exchange for not being rationed. Hence, the interest of an individual generator and its customers in adopting real-time pricing may be too small, because they can do too little to guarantee a steady flow of power.

These arguments suggest that in the presence of rationing—blackouts, in the case of electricity—real-time metering could generate positive benefits beyond those reaped by the generators and customers who adopt it. The same arguments may apply to substitutes for real-time pricing, that is, programs to reduce electricity use during peak periods, such as interruptible service contracts or private demand-side management programs. Whether the size of the externality warrants significant subsidies for real-time meters or more draconian measures, such as delaying open markets altogether, remains to be seen. The latter may be particularly dubious if the alternative is to maintain time-independent regulated rates.

In addition, we ought not ignore the possibility that the main problem in California was not merely that peak retail prices were too low but that the overall average price was too low. Those

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prices might have been below the price that would have best promoted efficient production and distribution of electricity, subject to the constraint that peak prices equal off-peak prices. Whether or not that was true, they were clearly below levels necessary to meet a constraint that revenues cover supplier costs. If prices are insufficient to keep suppliers in business, they have to be raised.

Bad Luck—Lack of Long-Term Contracts

A second idiosyncratic aspect to the California experience that has drawn a great deal of attention was regulated prohibition of the distribution companies hedging against high wholesale price increases through long-term contracts. If the dramatic increase in wholesale prices in summer 2000 had not been expected with a very high probability, as the previous two years of low prices would suggest, the utilities might have been able to obtain favorable long-term supply contracts at fairly low prices. Had they done so, they and the state of California would not be suffering the financial strains associated with bankruptcies and bailouts.

But as with real-time metering, it is important not to exaggerate the potential benefits of these contracts.⁹³ Such contracts should be regarded as equivalent to purchasing insurance from generators against high prices in the future. The price of the long-term contract, like an insurance premium, will reflect expected costs down the road. Like any other form of insurance, these

contracts are valuable only when there is uncertainty regarding wholesale prices, and the contracts reallocate risk from those who especially dislike it to those more willing to tolerate it. Accordingly, the merits of long-term contracting are intimately tied to the possibility of “bad luck” when the buyers (distributors) are more risk averse than the sellers (generators).

Looking at the absence of such contracts in hindsight is not very different from observing that someone whose house just burned down should have bought fire insurance. The effects in the short run are financial, not real in the sense of producing more electricity. Of course, because financial insolvency has real effects in a market where balance sheets constrain liquidity, the inability to insure against high wholesale prices via lock-in contracts has had real costs.

However, it is also important to realize that long-term contracts could have exacerbated the initial causes of the problem, had they been available. Like any insurance contract, they create a potential “moral hazard” problem. In this case, the moral hazard would be greater consumption of electricity at the lower contract price, when the equilibrium wholesale price and marginal cost of generating electricity would be greater. Just as fire insurance probably leads to more fires, long-term contracts could encourage electricity consumption when we want to discourage it. It is difficult to claim simultaneously that peak prices were too low, yet suppliers should have been able to enter into long-term contracts to keep prices low.⁹⁴

A more salient question would be whether the absence of long-term contracts discouraged electricity production. Long-term contracts, like other forms of insurance, do not produce output — just as fire insurance does not construct houses. Nevertheless, the inability to spread risk

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efficiently (taking moral hazard into account) could discourage entry by buyers or sellers. If fire insurance were impossible, people would likely buy fewer houses. With hindsight, it is difficult to come up with an argument that the absence of such contracts discouraged supply. The buyers had protection in the form of retail rate regulation. The utilities had an obligation to serve them, short of and probably regardless of bankruptcy. Generators would be deterred from entry or maintenance to prevent outage fearing the prospect of low prices, not high prices (leaving aside the prospect of nonpayment from bankrupt utilities).

Contracting might be valuable in the long run, particularly as wholesale price volatility in California has undoubtedly increased the importance of efficient risk sharing. However, long-term contracting carries some risk. Recall that a great deal of effort has gone into separating control wires from generation ownership, be it through divestitures or the creation of regional transmission operators, whether ISOs or stand-alone transmission companies. Long-term contracts between distribution utilities and generation companies are close cousins to vertical integration and thus could reconstitute the same incentives.

To mitigate such incentives, contracts could be regulated to prevent distribution companies from taking profit positions with generators through these contracts. They also might be monitored to ensure that generators are not able to influence distribution companies in how they construct and maintain their grids, insofar as those decisions could put competing generation companies or their customers at a disadvantage. But the best solution would be to get the distribution companies out of the retailing business entirely. Independent retailers could contract or be vertically integrated with generators, as they choose, to sell power at retail to their customers. The distribution companies would provide only local delivery at some regulated price, to cover the costs of constructing and maintaining the local grid. Keeping the distribution companies out of the competitive retailing and contracting businesses would further promote the goals underlying ISOs and RTOs, to keep competition undistorted by incentives of regulated monopolists to discriminate in favor of unregulated affiliates.

Auction Design

The design of the PX auction in which the distribution utilities had to buy all of their power also may be a culprit in the California situation.⁹⁵ The essential feature of these markets is that generators put in offers to sell power, and distribution companies and retailers put in bids to purchase power.⁹⁶ Because the major distribution utilities were generally obligated to serve most of their customers at regulated retail rates, their demands were essentially inelastic, based on forecasted loads. Generators, on the other hand, could bid in “supply curves,” with up to 16 price-quantity pairs.⁹⁷ For example, a generator could offer 200 MW of power at \$20/MWh and an additional 100 MW at \$40/MWh. The PX would find the price at which the amount generators offered equaled the quantity demanded. Each generator would then get that market-clearing price for all the supplies that were taken in the auction.

At first glance, the design seems reasonable. It appears to look like a regular market, in which all suppliers get to charge the price at which supply equals demand. Because each generator gets the market-clearing price, they would appear to have little reason to act strategically. They would have no incentive to put in bids above their costs of operation.⁹⁸ The supply curve produced by combining the bids would be akin to a supply curve in a competitive market.

Basic auction theory supports this intuition. When the price sellers get does not depend on their own bids, as in second-price, sealed-bid auctions or (equivalent) English (descending price for sellers) oral auctions, bidders have no incentive to refuse to make offers when the price they would receive is above their costs. More directly, no seller has an incentive to indicate a cost over its actual cost. Compatibility between the auction structure and the incentive to reveal bids truthfully renders the expected outcome efficient, in that the seller with the lowest cost will win. As the number of bidders increases, bids will tend to fall to the least-cost level, and the buyer reaps the gains.

Basic auction theory, however, applies to auctions that differ markedly from the California power auction. In the standard model, a single commodity (for example, a painting) is put up for bid. Here, multiple units of the commodity in question (megawatts of electricity) are for sale. Because multiple units are sought, sellers can decide how much to offer at any given price, with up to 16 combinations allowed. Also, because multiple units are offered, the quantity that will be sold in any given auction is not known in advance with certainty.

The rule that all bidders get the market-clearing price seems to mimic a textbook competitive market but differs from real-world markets in an important respect. In usual markets, if a seller finds a buyer willing to pay a high price for some of his output, the seller does not automatically get to charge that high price to all of its other past and future customers. This practice may change the incentives of the sellers. In the California electricity auctions, the implication is that generators may have an incentive to bid in a little bit of power at a very high price. If a generator's bid for that power is not taken, it does not lose much—only the profits from the small amount of sales. If the bid is taken, however, the generator could reap a windfall, in that it receives that high price on all of its output, not just the amount bid in at the high price.

A helpful analogy is a car dealership where several cars of the same model are on the lot. The dealer considers putting a very high sticker price on one of the cars, on the chance that someone might show up so desperate for a car that he or she would be willing to pay the high price. This tactic seems unprofitable. The cost is that the car sits on the lot unsold, and the only benefit depends on the slim chance that a customer with a high reservation price and unwilling to shop around would appear to buy that one car.

But now, change the scenario in two ways. First, suppose that demand for cars is suddenly large and inelastic, so that the chance of seeing this sufficiently desperate customer becomes significant, even if it is still small. Second, assume that if the car were to sell at this high price, the dealership would be able to go back to customers who had bought cars there previously and make them pay the high price as well. The car with the high sticker price may go unsold, but the expected benefits from setting the high price are now considerably greater.

The California electricity market may be like the second scenario, with desperate, inelastic demanders and the ability to charge all buyers—not only the desperate marginal buyer—the high price. The generators then could have an incentive to “game the system”⁹⁹ and bid in their last megawatt-hour at a very high price. The only cost is the foregone profits from selling that last megawatt-hour; while the expected gain is that all the power would be sold at that high price if it ends up being taken. As a result, “the system also encourages generators to bend bidding rules to move prices higher.”¹⁰⁰

This argument is speculative in a couple of respects. Empirically, we need to remember that the California system worked well for more than two years. We cannot conclude that the high

prices starting in June 2000 were the result of the exploitation of auction rules that had been in place since April 1998. Theoretically, this bidding tactic need not be an equilibrium strategy. Each member of a set of bidders may prefer to bid in all of its supply at cost and let someone else take on the burden of setting the high bid—so no one does it. Getting this outcome as an equilibrium could require some assumption that the benefit-cost ratio of the small high bid is so great that it overcomes in some probabilistic sense the tendencies toward the conventional Nash equilibrium.¹⁰¹

Even if each bidder finds it profitable to set a high price for some output, there is no positive equilibrium quantity to offer at the high price. The benefits to a generator of offering its last N megawatt-hours at the high price are the same as offering its last $N/2$ megawatt-hours at that high price, and its costs are lower, in that less power might be left unsold. To get an equilibrium with high marginal bids, a generator may need a minimum positive quantity to bid at any given price, but small enough so the cost of it going unsold is reasonably small.

If this “gaming” is a problem, what could we do? One possibility would be to drop the provision that everyone gets the market-clearing price. Although this response would eliminate the benefits of a generator sending in a high bid on its marginal output, it also eliminates the incentive to bid in most of its power at cost. Generators would make offers on the basis of the expected market price, resulting in lower supplies and higher prices overall. A second remedy would be to permit long-term contracts for power. Power under contract would not get a higher price if the noncontract day-ahead or hour-ahead price happened to be high, reducing the incentive to place high bids. A third suggestion would be to eliminate multiple bids, forcing suppliers to offer all power at the same price. A less draconian remedy would be to increase the minimum quantity that a generator would have to offer at any price at which it bids, to increase the cost of not being able to sell that power if that quantity were not taken.

The cleanest solution would be to eliminate central power auctions all together. In this way, electricity sales would be more like conventional markets, like the market for cars, in which each sale is at its own negotiated price. If we are going to retain centralized auctions, we need to be sure that the benefits of such auctions are worth the cost of setting up a system potentially subject to manipulation, because having central auctions is different from having a centrally managed grid. The justification for centralized control follows from the three properties of electricity identified in the introduction of this report: crucial importance, vulnerability, and interrelatedness. Whether this justification extends to require central markets for all power, as opposed to having a central grid coordinator procure reserve capacity or ancillary services as needed, remains an open question. But we should be sure that the predilection toward central auctions is based on more than a holdover feeling from the regulatory era that it is the job of a central planner, rather than a market, to enforce “least-cost dispatch,” that is, that no sold power costs more to produce than any unsold power.¹⁰²



CHAPTER SEVEN

Last, and Least or Most?

Market Power

Initial Observations

Perhaps the most controversial claim regarding the California situation is that it is the result of the last item on the “top 10” list, the exercise of market power by generators who supply power into California. To differentiate this issue from those associated with exploiting auction design, by *market power* we mean the withholding of output in order to raise price.¹⁰³

Market power allegations in this industry are not new. In March 2000, the Market Surveillance Committee of the California ISO found that California’s electricity markets had not been “workably competitive” during summer 1998 and 1999.¹⁰⁴ For the period July 1998 through September 1999, Borenstein, Bushnell, and Wolak found an average markup over the competitive price of 18.7%.¹⁰⁵ This markup would translate to a price-cost margin of about 15.8%.¹⁰⁶ These authors also noted that market power was less significant in 1999 than in 1998. In examining the interaction among generation companies, Puller used firm-specific price and cost data to find that the sellers “enjoy[ing] the highest price-cost margins” had price-cost margins of about 11%.¹⁰⁷

In light of the inherent imprecision in economic measurement, one may wonder whether these figures should have created much consternation. Perhaps ironically, these claims also call into question the role of market power in the California crisis. If generators exercised market power before June 2000 in raising prices 10–20% above variable cost, something else was responsible, at least in part, for causing prices to increase by factors of five or more above prior prevailing levels. As we see below, this does not mean that market power played no role whatsoever in the crisis. Moreover, one cannot say that just because market power was not significantly exercised prior to June 2000, it could not have been exercised afterwards. It is not a defense against an antitrust claim that a suspected violation did not happen earlier, despite identical market conditions. Still, the California experience does not suggest that opening power markets, in and of itself, leads to the exercise of sizeable levels of market power.

Is Collusion Plausible?

Market power can be exercised in one of two ways. First, a seller or sellers in an industry may be able to raise prices above costs in a market on their own. For example, a single firm may have sufficient market dominance that it might be able to raise prices even if other firms act competitively. A second possibility is that firms might make independent strategic choices to arrive at higher prices and lower output levels that would be expected under competition. This type of exercise of market power behavior, categorized as *unilateral effects*, is examined in the next section.

The second way in which firms might exercise market power is through *coordinated interaction*, that is, *collusion*, or working together to reduce output and raise prices.¹⁰⁸ Whereas the unilateral exercise of market power is not illegal, coordinated action or collusion is prohibited by the antitrust laws and other state statutes as well. The City Attorney of San Francisco filed a “business tort/unfair business practice” case in California state court against about a dozen named generators and “[yet unnamed] Does 1-200 inclusive,” alleging that the “defendants unlawfully manipulated the market for electric energy by fixing prices and restricting supply.”¹⁰⁹

We cannot say that collusion was not taking place. One aspect of electricity that facilitates collusion is that each seller’s electrons are indistinguishable from one another. It is harder for competitors to fix prices when there is no standard product as, for example, in markets where each brand has a different design or level of quality. In addition, selling on the PX and the absence of long-term contracts could facilitate collusion by making the spot price the single price on which to agree. Long-term contracting can also increase the rewards for a generator to “cheat” on the cartel, by enabling it to sell substantial amounts of power at a discount. The San Francisco City Attorney claimed that these generators “acted cooperatively based on information they shared amongst themselves and obtained from other sources, including the PX, the ISO, and the Western Systems Coordinating Council.”¹¹⁰

On the other hand, the sheer number of competitors in the California wholesale market (for example, as identified in the San Francisco City lawsuit) makes collusion unlikely. All of these firms would have to decide which among themselves would bear the cost of supply reductions (for example, taking generators out of service) to raise prices. Moreover, whereas a cartel has every incentive to raise prices, it does not have incentives to restrict supply to the point of creating an actual shortage—here, a blackout—or to put the buyers into bankruptcy. Because cartels are illegal, they have a strong interest in avoiding publicity and scrutiny. It is one thing to raise prices somewhat and quite another to create months of headlines and state and federal investigations brought about by blackouts and bankruptcies. But anything is possible, and investigation may uncover collusion, however unexpected it might be *a priori*.

Unilateral Theories

A more likely concern is that sellers might have found it unilaterally worthwhile to reduce output in order to set prices above cost. We can get some feel for the possibilities by looking at some standard models of unilateral effects. One would be the Cournot oligopoly model, in which firms choose outputs simultaneously and independently.¹¹¹ If the elasticity of demand for electricity is small (say 0.2), a market with 10 identical sellers—unconcentrated by conventional mea-

tures—would have a price-cost margin of 0.5 or, to put it another way, a 100% markup of price over marginal cost. With demand elasticity this low, markups of the magnitude observed by Borenstein, Bushnell, and Wolak or by Puller would require 30–45 sellers.¹¹² On the one hand, it suggests that prices may be high. On the other hand, it shows that one might observe substantial price-cost margins when this market is as competitive as could reasonably be expected.

Whereas we note that suppliers bid quantities as well as prices into the PX, we do not necessarily assert that the interaction among generators in California meets the Cournot model. However, qualitatively similar results are obtained when we use a “dominant firm/competitive fringe” model, in which a firm sets its price assuming that everyone else will match it.¹¹³ When capacity is tight—that is, supply is relatively inelastic—a firm with a small market share might nevertheless set prices considerably above marginal cost, even if it expects all other suppliers to increase output as best they can to match its price. For example, if $e_d = 0.2$ and $e_s = 0.1$, a firm with only one-seventh of the market would set price at twice marginal cost.¹¹⁴

These models suggest that Joskow and Kahn’s findings of Lerner indices in 2000 on the order of 48% for June, 36% for July, and 27% for August ought not be surprising.¹¹⁵ Again, in light of the calculations above, one might question whether these indices reflect extraordinary market power. However, five other factors should be considered before concluding that market power expressed through withholding output, rather than other items on the “top 10” list, was primarily responsible for the California troubles.

- *Timing*: Market conditions did not change, yet prices and (according to Joskow and Kahn) price-cost margins increased by multiples over historic levels.
- *Outages*: To exercise market power, as opposed to gaming the auction system, output needs to be reduced. One allegation is that suppliers took generators out of service, in part to raise price. A FERC study of the California summer 2000 situation “did not discover that the audited companies were scheduling maintenance or incurring outages in an effort to influence prices.”¹¹⁶ Outages could be more frequent under competition, simply because maintenance expenses under cost-of-service regulation could be passed on to consumers as part of the revenue requirement.¹¹⁷
- *The price one gets, not the price one charges*: PG&E’s declaration of bankruptcy, and the months in which generators were ordered to supply power into California without assurance of getting paid, are reminders that the relevant price in a Lerner index calculation is not the price sellers charge, but the revenue per unit they get. This is surely more of a problem in assessing market power in fall 2000 and winter 2001 but may merit consideration in assessing prices because utility debt mounted in summer 2000.
- *Measuring marginal cost*: The care with which analysts have measured marginal cost is impressive. Nevertheless, simulating electricity generation systems on the desktop may not provide a sufficiently accurate measure of real-world marginal costs on which to base claims that price-cost margins were out of line. Joskow and Kahn’s 46% Lerner index may well be outside the margin of observational error (as opposed to statistical variation); observed indices in the 10–15% range for 1998–1999 may be as consistent with “workable competition” as can be practically ascertained.

■ *Defining marginal cost:* The prevailing method for measuring price-cost margins or markups is to compare price with a measure of the average variable cost of the highest-cost producer in the market. For markets with excess capacity, this approach is reasonable. However, the long-run equilibrium price in a market will be roughly the average total cost of the highest-cost producers.¹¹⁸ In equilibrium, prices have to be high enough so that the marginal entrant will expect to cover its total costs, including the capital expense.¹¹⁹ It suggests, specifically, that during peak periods such as summer 2000, calculations based on average variable cost will overstate the difference between observed prices and those that would be seen under competition.¹²⁰

None of this is to deny the possibility, and perhaps the likelihood that market power is being exercised, particularly unilaterally. But it may be prudent to regard the question as still open.

If unilateral market power is a problem, the antitrust laws are not an effective remedy. If a firm legally acquired its market position, as seems the case with the generators selling in California, they can charge under the law whatever they want. Allowing generators to sell power under long-term contract might mitigate the incentive to raise prices. As discussed above in looking at auctions, raising spot prices by withholding electricity therefore is less profitable when the price of some of the generator's production was fixed by contract.¹²¹

If we conclude that the market is insufficiently competitive and that the high prices are not the fault of market conditions, regulatory distortions, or the auction rules, then one of two difficult remedies is necessary. The first would be an order, perhaps requiring additional legislative authority to FERC or whichever entity would issue the order, to force generation companies to divest some of their plants to deconcentrate the market. Such a divestiture would be unprecedented in an industry as nominally unconcentrated as electricity generation.

If that strategy fails as a matter of law, economics, or politics, the alternative would be to regulate wholesale generation. If the California experience comes to teach us that intolerable levels of market power are inevitable allowing for reasonable-scale economies in generation, it would be hard to avoid the conclusion that competition is untenable.¹²²

■ ■ ■

CHAPTER EIGHT

Concluding Observations: Education or Diversion?

Political Issues

The intensity of the California situation can distract us from its specificity, in many respects. In turn, it can lead us to forget some of the generic issues that continue to face federal and state regulators as they proceed with opening electricity markets.

A continuing matter is whether retail markets should continue to be a federal issue. On the transmission side, the grids and relevant markets are interstate in nature. Policies to facilitate expansion of capacity and efficient control would likely be most effective at the national level. Reasonable pricing, nondiscriminatory access, and system reliability will likely remain federal issues. Congress also may have to reform or repeal laws that impede interstate operations or place burdens on incumbent utilities that may not be feasible when unencumbered firms can enter the market. However, the California experience also shows the virtue in letting states decide whether and how to implement retail competition. Without knowing exactly which methods work the best, letting each state serve as a laboratory from which the others can learn and restricting the scope of mistakes to a state has now-obvious virtues. In retrospect, calls for federal legislation to mandate retail competition might well have led to the California crisis on a national scale.

Regulators also will likely be concerned with distributional battles. Part of the reason California continued retail rate regulation was to settle a concern that industries, rather than households, would gain the most from restructuring. In fact, some industrial customers received discounts and more effectively exerted their clout when politics, rather than markets, set electricity prices. At the national level, a predictable effect of opening retail markets is nationwide rate averaging, with prices falling in high-cost areas and rising in low-cost areas. Although the net national benefits are positive (analogies to “free trade” apply), low-cost states will be under some pressure to come up with policies to keep rates low. It remains to be seen whether policies to, say, tax out-of-state sales or windfall profits are beneficial, feasible, and constitutional.

Many so-called social regulation questions also remain on the table. Policymakers have already considered the merits of requiring power marketers to provide standardized information to consumers on prices and environmental effects, akin to nutrition labels on food.¹²³ Consumer protection measures, such as preventing “slamming” (switching providers without the consumers’

consent) and “cramming” (providing unwanted extra services), may arise here as it arose in telecommunications deregulation.¹²⁴ We might also include in this category environmental rules, whereby moving to a competitive environment is likely to make incentive-based policies (such as pollution taxes and emissions trading programs) more effective, perhaps rationalizing stricter caps. Policies that force incumbent utilities alone to pay for demand-side management programs or support the renewable fuels industry are likely to become infeasible, leaving aside the question of whether such programs are necessary if competition encourages cost-based pricing.

Regulators also will have to consider the role of public power systems. When the alternative is regulation, the choice between public power and IOUs is the subtle one of organizational economics—that is, whether performance is better with vertical integration between the government and the power provider or through an implicit regulatory contract between the government and the utility.¹²⁵ In a competitive environment, however, public power systems have several advantages (preferential access to discounted federally produced power, access to tax-deductible state bond financing, and public backing of debt) that could distort electricity markets as they develop. Restricting future tax breaks and advantages to expenses related to the non-competitive sides of the business (that is, transmission and distribution) could mitigate these problems.

Can It Happen Elsewhere?

The main question on the minds of observers who do not live in California is whether the situation in that state will be repeated elsewhere. Because the causes of the California crisis are many and varied—it is often compared with “the perfect storm”—it is difficult to say. The most crucial factor, which is beyond the scope of this report, is the overall supply-and-demand situation in each state or region, which takes into account generation capacity, fuel prices, and transmission availability on the supply side and population and economic growth on the demand side. These questions may have little to do with restructuring. Public utility commissions around the country will have to monitor these issues for the potential for high costs and blackouts in their states even if the industry remains regulated.¹²⁶

The California experience does offer some lessons, however, that those charged with implementing retail competition might consider.

Retail price controls

A first suggestion would be to lift retail price controls. If there is sufficient concern about retail market power to warrant retail price caps, because incumbent utilities or their spin-offs (see below) continue to dominate retailing and entry will not be forthcoming, continued regulation should allow pass-through of wholesale prices, particularly during periods of peak demand.¹²⁷ If peak-period prices continue to be held below cost by regulation, bring about some of the conservation that would have been induced by cost-based prices (for example, via public demand-side management programs directed at peak-use equipment).¹²⁸ If peak-period rolling blackouts cannot be restricted to relatively low-valued uses of electricity, consider ways to encourage real-time pricing or its equivalent, including subsidized real-time meters and interruptible service contracts.

Market design

Permit, do not prohibit, long-term contracting between retailers and generators. To prevent creating incentives for anticompetitive conduct, long-term contracting should be offered first to retailers not affiliated with distribution utilities. If long-term contracting among unaffiliated retailers is not adequate, consider ordering distribution utilities to divest their retail operations to become passive regulated wires companies. Such a divestiture could result in more than one retail company, to limit the need for retail price controls. In considering the merits of direct dealing between purchasers and suppliers of electricity, one might want to discourage the alternative and eliminate central auctions for all but ancillary services and information provision necessary to maintain system integrity. If such auctions need to be retained, consider requirements that a substantial minimum quantity be bid in at any given price or that a supplier must bid in all of its output at the same price to prevent gaming.

Environmental policy

It may also be necessary to factor higher electricity prices into the cost-benefit calculation in assessing environmental regulations. This should not be a license to ignore environmental costs—those costs of producing electricity than the cost to build power plants, the fuel to feed them, and the labor to operate them. It is only a suggestion to balance them more accurately against any reduction in electricity supply or generation reserves. The environmental “lunch” was never “free,” but the meal might be more somewhat more expensive than previously thought.

Market power and wholesale price caps

The last category of policy recommendations involves market power. If evidence supports the view that generators have market power, empower FERC or public utility commissions to order additional divestitures to deconcentrate the market, if possible, because the antitrust laws do not limit a firm’s ability to reduce output unilaterally in order to raise price. Regulation of output could be considered, for example, a “sick day” limit on outages.¹²⁹

The dominant controversy is over the need to cap wholesale prices to limit market power. The best case for capping wholesale power prices is if generators can unilaterally exercise significant market power, or if a “game-able” auction remains in place. Caps are not necessary to control collusion; agreements to fix electricity prices are illegal under the antitrust laws. Using a cap as a kind of windfall profits tax may be appealing, but approach the issue with caution. Wholesale price caps may discourage production and encourage consumption, putting the system at greater risk down the road.

Claims that wholesale price caps are only “temporary” should also be treated cautiously. Without a very clear indication of what makes California different, those calls are tantamount to saying that competition works only in the easy case, when multiple sellers have substantial excess capacity. If caps are imposed whenever electricity becomes scarce, we essentially have re-regulated the industry. Theoretical and empirical analyses discussed above indicating that even relatively unconcentrated electricity markets may lead to very high prices may suggest that some regulation of wholesale prices may be warranted, particularly during peak periods. If so, price caps being proposed and adopted today may be with us in some form for quite some time.

Is California the Right Focus? Reliability versus Markets

The most important cautionary note in emphasizing the severity of the California crisis is, ironically or perhaps paradoxically, that it may give a false sense of security regarding the merits of opening retail markets to competition. Most of the problems in California are among those we know how to solve or prevent. Antitrust laws, with additional deconcentration policies if necessary, can deal with market power. Mistakes in the design of residual regulation and centralized auctions can be avoided. The most difficult items in the list (those dealing with supply-and-demand imbalances) will be with us, perhaps even more intensely, even if retail regulation continues.

However, thinking we have solved or can solve these problems could lead us to think that without these obvious (at least in hindsight) errors, electricity markets can work just fine. Perhaps that is so. However, the factors that make electricity unique—its crucial role in the economy, vulnerability to load imbalances, and inter-relatedness—together imply that some level of cooperation or centralized management of the system will remain necessary to ensure reliability.

Excepting the California problem, system failures in the United States are almost always local in nature, for example, when lightning hits a utility pole or local substation. Wide-area failures, such as the New York City and northeast black-out in 1965 or problems in the western United States in 1996, are exceptional. Will this record continue with greater competition in electricity? Or is it an artifact of an era when the major utilities were not competing with each other but each held geographically distinct franchised monopolies?

Before California, the most likely threat to restructuring as a policy movement was a large-scale systemic breakdown followed by finger pointing, because no one would claim responsibility for ensuring reliability. A question worth careful consideration is whether competition is compatible with the centralized control necessary to prevent systemic breakdowns. We may be able to ensure reliability by holding individual generators responsible for losses incurred when they fail to meet the needs of their customers.¹³⁰ These strategies may not work when, say, the losses due to breakdowns are beyond the ability of generators to pay. The time it takes the legal system to settle liability issues, which may be adequate for most sectors of the economy, may be inadequate in the electricity market, in which systems must be kept in balance continuously.

If these considerations imply central planning, the question of the compatibility between competition and central control becomes whether the role of that planner—a regional reliability council, RTO, ISO, distribution utility, or regulator of any or all of these entities—will leave sufficient scope for competition to be meaningful. If the central coordinator can limit its activity to relatively small and occasional purchases of ancillary services, then the rest of the generation and marketing sectors will likely remain large enough to make competition worthwhile. But the more that coordinator has to extend its reach into managing transactions, purchasing, and perhaps owning generation outright, the scope of competition will shrink. Whether we can ensure the consistency of competition with the central coordination necessary to maintain system reliability remains the most significant test restructuring has to pass. The list of flaws in the California experiment implies that we still cannot predict the outcome.

*Electricity could be the
sector in which markets
meet their match.*

To end on a broader note: in debates about deregulation, its advocates and opponents generally treat deregulation as a matter of theory, at best, or ideology.¹³¹ The electricity industry, more than most if not all other industries, asks whether “markets or not?” is an empirical question. Market advocacy may be stronger over the economy as a whole if it concedes that the question is in fact empirical. Perhaps electricity, too, will join the list of industries in which the benefits of deregulation have proven positive. But perhaps electricity will be the sector in which markets meet their match.

■ ■ ■

Notes

1. Figures for 1999 compared from Bureau of Economic Analysis, U.S. Department of Commerce, *Gross Domestic Product by Industry in Current Dollars*, at www.bea.doc.gov/bea/dn2/gpoc.htm#1993-99.
2. In economic terms, the “consequence” to which this refers is the difference between gross consumer surplus and revenue or, equivalently, average willingness to pay for electricity compared with the much lower value of the marginal unit.
3. *Renewable* is as much a term of political art as of physical science. It generally refers to power sources that do not rely on the use and eventual exhaustion of virgin carbon-based fossil fuels. In principle, the idea is to refer to generation technologies that rely on energy that, in some sense, is already available, either occurring naturally in the environment (solar, wind, or geothermal energy) or using material that would otherwise be discarded (biomass, some of which may come from dedicated forests). Nuclear power is typically not included in this category. A more surprising frequent omission is hydroelectric power. What the two have in common are undesirable environmental effects unrelated to air pollution: radioactive waste from the former, and flooded lands and blocked fish spawning paths from the latter. In short, *renewable fuel* in practice is as much a shorthand description for fuels that the user of the term regards favorably as it is a reference to an objective property related to the empirical renewability.
4. M. Crew and P. Kleindorfer, *The Economics of Public Utility Regulation*, Cambridge, MA: MIT Press, 1986.
5. For a review of these environmental effects, see T. Brennan, K. Palmer, and others, *A Shock to the System*, Washington, DC: Resources for the Future, 1996, pp. 112–114.
6. Whether this is in fact true at times when demand is high relative to capacity in the market is a question we consider below.
7. How such regulation should be implemented remains a difficult question. Absent congestion, the marginal cost of using a transmission grid is small; apart from energy losses borne by the generators, it is virtually zero. Rates might be based on distance nonetheless to provide some appropriate long-run locational incentives. When lines are congested, theory suggests route-based or “nodal” pricing, reflecting complexities related to loop flow. However, if transmission providers keep congestion rents, they have incentives not to expand lines. Transferring rents away (for example, to generators through markets in “congestion rights”) may leave ISOs or transmission companies with little funds or incentive to expand.

8. This problem most notoriously arose in telecommunications and rationalized the eventual breakup of AT&T in 1984, when it agreed to divest its regulated local telephone companies. For a discussion of the rationale, see T. Brennan, "Why Regulated Firms Should Be Kept Out of Unregulated Markets: Understanding the Divestiture in *U.S. v. AT&T*," *Antitrust Bulletin* 32, 1987, 741-793.
9. It is important to keep in mind that the price savings would be only on the energy and marketing components of the electricity sector. Electricity transmission and distribution will remain regulated for the foreseeable future.
10. The U.S. Department of Energy estimates savings of "at least \$20 billion" from an industry \$212 billion in size ("Comprehensive Electricity Competition Plan" at www.hr.doe.gov/electric/plan.htm).
11. A. Ando and K. Palmer, "Getting on the Map: The Political Economy of State Level Electricity Restructuring," Resources for the Future Discussion Paper 98-19rev, March 1998, at www.rff.org/CFDOCS/disc_papers/PDF_files/9819rev.pdf.
12. In 1999, the average revenue per kilowatt-hour paid by consumers was 8.09¢; the similar figure for industrial users was 4.27¢ (Energy Information Administration, U.S. Department of Energy, "Table 53: Estimated U.S. Electric Utility Average Revenue per Kilowatt-hour to Ultimate Consumers by Sector, Census Division, and State, November 2000 and 1999," at www.eia.doe.gov/cneaf/electricity/epm/epmt53p1.html).
13. Standard references for this proposition are M. Olson, *The Logic of Collective Action* (Cambridge, MA: Harvard University Press, 1965); G. Stigler, "The Theory of Economic Regulation," *Bell Journal of Economics and Management Science* 2, 1971, 3-21; and S. Peltzman, "Toward a More General Theory of Regulation," *Journal of Law and Economics* 19, 1976, 211-240.
14. See n. 5 *supra* and accompanying text. For an example of policy advocacy of electricity restructuring based on the possibility for green power marketing, see Carol M. Browner, EPA Administrator, Remarks Prepared for Delivery, Electricity Restructuring News Conference, U.S. Environmental Protection Agency, Washington, DC, April 15, 1999. Whether the results would be significant in the marketplace remains to be seen. Consumers would be contributing to a public good for which others are the primary beneficiaries. Perhaps more concretely, if one consumer is willing to pay for "green" power and another is indifferent, then the former's increase in use of "green" power may be matched by a reduction in use of such power by the latter, resulting in no net protection of the environment.
15. This possibility is one main reason why opening markets to competition weakens the case for demand-side management policies to subsidize the purchase of high-efficiency appliances and otherwise promote energy conservation. T. Brennan, "Demand Side Management Programs under Retail Electricity Competition," RFF Discussion Paper 99-02, 1998, at www.rff.org/CFDOCS/disc_papers/PDF_files/9819rev.pdf.
16. Much of this summary is from Brennan, Palmer, and others, n. 5 *supra* at chapter 2.
17. Both federal and state governments have authority over regulating emissions from utilities, but in that realm the federal role is dominant.
18. Literally, the power produced by a particular generator does not go to that generator's customer. More precisely, if a generator sells *N* kilowatts of

power to its customer, it is committing to inject N kilowatts of electricity into the overall electricity system at the same time that the customers are taking N kilowatts out of it. It is as if Starbucks sold M cups of coffee by dumping the equivalent of M cups into a common vat, out of which its customers had the right to pour out M cups of coffee.

The precise description of the market has two notable consequences. The first is that the opportunities to differentiate one's electricity product itself are limited. One cannot sell "higher power" electricity or current that alternates at a different speed. Thus, opportunities to differentiate the product have to be based on other factors, such as how the power is generated (for example, renewable versus fossil fuel) or whether it is provided in conjunction with capital equipment.

A second consequence is that the distinction between the central system (that is, the "grid") and the power pooled within it can become blurry. If coffee were sold as suggested in the Starbucks scenario, one might well expect that the owner of the vat might become involved in the wholesale purchase and retail sale of the coffee within it. This blurriness could be especially pronounced if the vat owner became responsible for the quality of the coffee supplied, that is, making sure that the caffeine jolt is "reliable." We discuss below how these considerations have affected and may continue to affect the development and feasibility of competition in electricity markets.

19. At the same time, FERC issued Order 889 requiring utilities to institute an Open Access Same-Time Information System (OASIS) so generation companies have up-to-the-minute information on transmission line prices and availability.
20. See n. 8 *supra* and accompanying text.
21. FERC, Regional Transmission Organizations, Order 2000, Jan. 6, 2000, at www.ferc.fed.us/news/1/rules/pages/order2000.htm.
22. FERC, Regional Transmission Organizations, Order Initiating Mediation, Docket No. RT01-99-000, July 12, 2001, concurring statement of Commissioner Massey at 4, at www.ferc.gov/Electric/RTO/rto/issuance/rto1-99-000july.pdf.
23. Energy Information Administration, U.S. Department of Energy, April 1, 2001, at www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html.
24. D. Burtraw, K. Palmer, and M. Heintzelman, "Electricity Restructuring: Consequences and Opportunities for the Environment," Resources for the Future Discussion Paper 00-39, 2000, at www.rff.org/CFDOCS/disc_papers/PDF_files/0039.pdf.
25. Whether this price reduction would increase the inefficiency associated with a failure to take environmental externalities into account is an open question as a theoretical matter. Although the output of electricity and the volume of emissions would increase, the social cost of electricity, including the cost of emissions, would fall. The latter effect can outweigh the former, reducing (but not eliminating) potential benefits of otherwise costless environmental policies. T. Brennan, "Do Lower Prices for Polluting Goods Make Environmental Externalities Worse?" RFF Discussion Paper 99-40, 1999, at www.rff.org/CFDOCS/disc_papers/PDF_files/9940.pdf.
26. Available at www.hr.doe.gov/electric/cecp.htm. For a summary and evaluation, see T. Brennan, "Transforming Power Markets: An Analysis of the Clinton Administration's Comprehensive Electricity Competition Plan," May 16, 1998, at www.rff.org/misc_docs/brennan_oped.htm. A version of this plan was introduced by Senator Murkowski as the "Comprehensive Electricity Competition Act" (S. 1047) in 1999. It did not pass.
27. For the experience in Norway, see Statistics Norway, Electric Energy Prices, 4th quarter 2000, at www.ssb.no/english/subjects/10/08/10/elkraftpris_en/.

28. Competition Commission, *AES and British Energy: A Report on References Made under Section 12 of the Electricity Act 1989*, 2001, 126, at www.ofgem.gov.uk/docs2001/compcomm2.pdf (chapter 7, “The England and Wales Wholesale Electricity Market”); the introduction of the report can be found at www.ofgem.gov.uk/docs2001/compcomm1.pdf.
29. europa.eu.int/rapid/start/cgi/guesten.ksh?p_action.gettxt=gt&doc=IP/01/356101RAPID&lg=EN.
30. Calculated from the California Energy Commission’s figure of 252,800 gigawatt-hours of consumption in California [California Energy Commission, “California Electricity Consumption by Sector (1990–2000),” at www.energy.ca.gov/electricity/consumption_by_sector.html] multiplied by the U.S. Department of Energy’s estimated average price of 9.03¢ per kilowatt-hour (see n. 32 *infra*).
31. The California figure is calculated from California Energy Commission data at the table referenced in n. 30 *supra*. The U.S. figure was calculated from production data in Energy Information Administration, U.S. Department of Energy, “Table 2: U.S. Electric Power Industry Summary Statistics,” at www.eia.doe.gov/cneaf/electricity/epm/epmto2p1.html, and Bureau of Census estimates of the U.S. population on July 1, 1999.
32. Energy Information Administration, U.S. Department of Energy, California State Electricity Profile, at www.eia.doe.gov/cneaf/electricity/st_profiles/california/ca.html.
33. California Energy Commission, “California’s Major Sources of Energy,” at www.energy.ca.gov/html/energysources.html.
34. Energy Information Administration, U.S. Department of Energy, “Table A21: Retail Sales of Electricity,” at www.eia.doe.gov/cneaf/electricity/epav1/ta21p1.html.
35. California Energy Commission, “Map of Electricity Market in California,” at www.energy.ca.gov/maps/electricity_market.html.
36. California Energy Commission, “Map of Electric Utility Districts in California—1996,” at www.energy.ca.gov/maps/map_electric_utility.html.
37. See the history of AB 1890 at www.assembly.ca.gov/acs/acsframeset2text.htm. The unanimity of passage reflected the wide consensus of utilities, industrial users, environmentalists, consumer groups, and regulators that restructuring was a good idea. It also explains the paucity of finger pointing as the California crisis developed, relative to the magnitude of the problem.
38. Energy Information Administration, U.S. Department of Energy, “Provisions of AB 1890,” at www.eia.doe.gov/cneaf/electricity/california/assemblybill.html.
39. Energy Information Administration, U.S. Department of Energy, “Subsequent Events,” at www.eia.doe.gov/cneaf/electricity/california/subsequentevents.html.
40. *Id.*
41. California Energy Commission, “Retail Market Activity through January 1999,” at [38.144.192.166/electricity/retail_market_activity/1999-01.html](http://www.energy.ca.gov/cneaf/electricity/retail_market_activity/1999-01.html).
42. California ISO, “Event Log,” at www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.pdf.
43. These were only Stage 1 and Stage 2 emergencies, with reserves never less than 1.5% of capacity. In fact, only once during all of 2000 was a Stage 3 emergency declared, where reserves were even lower, on Dec. 7, 2000.
44. California ISO, n. 42 *supra*.
45. In the PJM wholesale market that serves most of Pennsylvania, New Jersey, Maryland, Delaware, and the District of Columbia, average monthly prices since 1997 have been less than \$30/MWh with only three exceptions in more than four

- years, and only once, in July of 1999, was the average price (about \$90) above \$45. This example, too, suggests that deregulation alone is not the culprit. A. Ott, “PJM Energy Market,” presentation at the Energy Information Administration, U.S. Department of Energy, Jan. 30, 2001.
46. California ISO, “Comments on Staffs’ Recommendation on Prospective Market Monitoring and Mitigation,” FERC Docket No. EL00-95-012, March 22, 2001, at www.caiso.com/pubinfo/FERC/filings/index.html.
 47. California Power Exchange press release, “CalPX to Suspend Day-Ahead, Day-of-Market Operations,” Jan. 30, 2001. On March 9, 2001, the PX filed for Chapter 11 protection under the bankruptcy laws.
 48. *California ISO v. Reliant Energy, et. al.*, No. CIV. S-01-238 (E. Dist. Calif., Feb. 8, 2001). This and related decisions are available at www.caed.uscourts.gov/.
 49. AB 1X, passed Jan. 31, 2001.
 50. Transcript of Press Conference, Gov. Gray Davis (Feb. 16, 2001).
 51. J. Woolfolk, “California Power Crisis Drives Alternative Power Services out of Business,” *San Jose Mercury News*, Feb. 20, 2001.
 52. D. Bunis and K. Berry, “Electricity: Davis Says Deals for Major Utilities’ Transmission Lines Will Be Signed in a Few Weeks,” Feb. 28, 2001, Gov. Davis’s website, “In The News,” at www.state.ca.us/state/portal/myca_homepage.jsp.
 53. Transcript of Press Conference, n. 50 *supra*.
 54. Note that income interest on bonds used to finance these initiatives would be exempt from federal taxation, in effect bringing the national government in as a partial financier of the recovery program.
 55. South Coast Air Quality Management District Rule 118 Executive Order #01-03, Feb. 8, 2001, at www.aqmd.gov/news1/Exec_order_01_03.htm; P. Joskow and E. Kahn, “A Quantitative Analysis of Pricing Behavior in California’s Wholesale Market during Summer 2000,” AEI-Brookings Joint Center for Regulatory Studies Working Paper 01-01, 2001, 15-16.
 56. See additional cases at the website given in n. 48 *supra*.
 57. “Order Directing Sellers to Provide Refunds,” *San Diego Gas & Electric Co. v. Sellers of Energy*, FERC Docket No. EL00-95-017, March 9, 2001.
 58. E. Hildebrandt, “Further Analysis of the Exercise and Cost Impacts of Market Power in California’s Wholesale Electricity Market,” California ISO, March 2001; Appendix B to n. 46 *supra* at 10. Part but not all of the dispute centers on FERC’s decision to award refunds only for power sold during peak-demand or emergency periods.
 59. D. Lazarus, “PUC Votes to Jack Up Power Rates,” *San Francisco Chronicle*, March 28, 2001.
 60. Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electricity Markets and Establishing and Investigation of Public Utility Rates in Wholesale Western Electricity Markets, *San Diego Gas and Electric Co. v. Sellers of Energy*, Federal Energy Regulatory Commission Docket No. EL00 95-031, issued Apr. 26, 2001, at 10, 14-15, available at www.ferc.gov/electric/bulkpower/el00-95-012A.pdf.
 61. *Id.* at 15-16.
 62. Order on Rehearing of Marketing and Mitigation Plan for the California Wholesale Electricity Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference, *San Diego Gas and Electric Co. v. Sellers of Energy*, Federal Energy Regulatory Commission Docket No. EL00 95-031, issued Jul. 12, 2001, at 4-7, 24-25, 35-36, 41-42, available at www.ferc.gov/electric/bulkpower/el00-95-031-6-19.PDF.
 63. *Id.* at 6-7, 41-42.
 64. *Id.* at 8, 40.

65. *Id.* at 8, 46-47.
66. Report and Recommendation of Chief Judge of Record, San Diego Gas and Electric Co. v. Sellers of Energy, Federal Energy Regulatory Commission Docket No. ELOO 95-031, issued Jul. 12, 2001, at 3, available at www.ferc.gov/electric/bulkpower/ELOO-95-031_7-12-01.pdf.
67. *Id.* at 5.
68. *Id.* at 3.
69. North American Electric Reliability Council, *2001 Summer Assessment: Reliability of the Bulk Electricity Supply in North America*, May, 2001, 4, at ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/summer2001.pdf.
70. Kahn, Michael, "Relief in California as Summer Blackout Threat Recedes," Reuters, Sept. 9, 2001, at dailynews.yahoo.com/h/nm/20010909/ts/utilities_california_blackouts_dc_1.html.
71. "California Power Costs Continue to Tumble in August," Reuters, Sept. 19, 2001, at biz.yahoo.com/rf/010919/n19218251_1.html.
72. Natural Resources Defense Council and Silicon Valley Manufacturing Group, *Energy Efficiency Leadership in a Crisis, How California is Winning*, Aug. 2001, 1, at www.nrdc.org/air/energy/eeca/eeca.pdf.
73. Kahn, n. 70 *supra*.
74. Gaudette, Karen, "Regulators End Consumer Choice, Raise San Diego Power Rates," SFGate, Sep. 20, 2001, at www.sfgate.com/cgi-bin/article.cgi?file=/news/archive/2001/09/20/state1554EDT0105.DTL&type=news.
75. Energy Information Administration, Department of Energy, "The California Electricity Situation: Background," at www.eia.doe.gov/cneaf/electricity/california/background.html.
76. *California State Auditor*, "Energy Deregulation: The Benefits of Competition Were Undermined by Structural Flaws in the Market, Unsuccessful Oversight, and Uncontrollable Competitive Forces," March 2001, 6. There is considerable debate about the extent to which the Internet and information technology are responsible for this demand growth. Claims of significance, for example, that the Internet is responsible for 8% of electricity use, can be found by the Greening Earth Society (a pro-CO₂ group), "*The Internet Begins with Coal*," Greening Earth Society Releases New Report by Science Advisor Mark Mills," June 1, 1999, at www.fossilfuels.org/Electric/internet.htm. For arguments that such claims are overstated, see A. Chen, "Research Finds Computer-Related Electricity Use to be Overstated," *Berkeley Lab Science Beat*, Feb. 1, 2001, at enews.lbl.gov/Science-Articles/Archive/net-energy-studies.html.
77. McKinsey and Company, *The Bay Area—A Knowledge Economy Needs Power*, Bay Area Economic Forum, April 2001, 8.
78. T. Winter, Statement before the House Committee on Government Reform, Sacramento, CA, April 10, 2001, at www.caiso.com/docs/09003a6080/od/23/09003a6080od232d.pdf. On p. 2, Winter writes, "Path 15 [the main transmission line in California] constraints, and the ISO's resultant inability to deliver critical supplies of power to Northern California, were the primary cause of the most recent rolling blackouts in California."
79. FERC, Staff Report on Western Markets and the Causes of the Summer 2000 Price Abnormalities Nov. 1, 2000, 3-20, at www.ferc.fed.us/electric/bulkpower/section3.pdf.
80. A related and perhaps accurate acronym is BANANA, for "build absolutely nothing anywhere near anything."
81. California Energy Commission, "Siting Constraints Order Instituting Informational Proceeding," Docket #00-SIT-2, Jan. 28, 2001, at www.energy.ca.gov/siting/constraints/index.html.
82. Sierra Club, "Energy: The California Energy Shortage," at www.sierraclub.org/energy/california/.

83. FERC, “Order Directing Remedies for California Wholesale Markets, *San Diego Gas and Electric v. Sellers of Energy and Ancillary Services*,” Docket No. ELOO-95-000, Dec. 15, 2000, 5.
84. *California Power Exchange Corporation v. FERC*, Docket No. 01-70031, 9th Circ., Apr. 11, 2001.
85. See n. 4 *supra* and accompanying text.
86. See n. 57 *supra* at 4.
87. During the summer of 1998, wholesale prices in the Midwest rose from \$25/MWh to more than 100 times that much, with prices during one hour on June 25 reaching \$7,500/MWh. FERC, “Staff Report on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest during June 1998,” Sept. 22, 1998, vi, at www.ferc.fed.us/electric/mastback.pdf.
88. It also may mitigate the “stranded cost” problem, enabling generators to recover the costs of investments made during the regulated era that supposedly would not have been recovered in a competitive environment. For more on the issue, see T. Brennan and J. Boyd, “Stranded Costs, Takings, and the Law and Economics of Implicit Contracts,” *Journal of Regulatory Economics* 11, 1997, 41–54.
89. Even in San Diego during summer 2000, peak costs were averaged in with costs over the monthly billing period. Were there real-time pricing, San Diego consumers might have seen prices increase by factors considerably greater than three, but for only limited times during the month.
90. S. Stoft, “The Market Flaw California Overlooked,” *New York Times*, Jan. 2, 2001, A19.
91. Appendix A presents estimates of the benefits of real-time pricing based on elasticities of electricity supply and demand.
92. To continue the restaurant analogy, suppose we really want to get into the restaurant but are back in the waiting line, and there is no way for us to pay to be up front. We get positive benefits if those waiting in front of us adopt a technology that gets them to adopt real-time restaurant pricing, with perhaps some of them getting out of the line and allowing us to move up.
93. We discuss below some of the benefits of long-term contracting in reducing the incentive of generators to bid prices substantially above the production cost of power.
94. If a retail electricity seller obtains only some of its electricity through long-term contracts, its marginal cost of electricity at wholesale would equal the spot price. Retail prices would thus follow the spot price. If so, the long-term contracts would have little direct effect on the prices consumers pay. The retailer and generator would share the revenues, rather than the generator getting them all, as when long-term contracts are absent.
95. Complications regarding ancillary service markets and relationships among them, and incorporating transmission congestion fees, may be important but are neglected here.
96. We leave aside some complications about when the auction takes place, in “day ahead” or “hour ahead” markets, and that bids were submitted for each hour of the day. For a discussion of how such considerations affect the relationship between bids and marginal costs, see n. 120 *infra*.
97. California Power Exchange, “California Electricity Market Primer,” draft, Jan. 28, 2000, Chapter II, p. 3, at www.calpx.com/news/publications/D%20-%20Primer%20Chapter%20III.pdf.
98. Another complication neglected here is that some generators may find it costly to shut down and then restart. Thus, they might bid in a price of zero, that is, that they should be put on “must run” status, to ensure that they do not have to bear shut-down and start-up costs. These generators still would receive the market-clearing price.
99. This is my interpretation of that oft-used phrase in this context. Market power scenarios are considered below.

100. R. Schuler, New York ISO Board, quoted in *The New York Times*, Feb. 25, 2001, p. 22.
101. For a review of auction models that support such a result, with evidence that it occurred in Britain, see C. Wolfram, “Strategic Bidding in a Multi-Unit Auction: An Empirical Analysis of Bids to Supply Electricity in England and Wales,” *Rand Journal of Economics* 29, 1998, 703–725.
102. One could imagine a proposal that all coffee should be bid by suppliers into a single “coffee exchange,” so that an “independent caffeine operator” could ensure that only the lowest-cost coffee was sold. Undoubtedly, in the coffee business and others, markets do not perfectly ensure least-cost dispatch. This situation does not warrant the wholesale adoption of centrally managed exchanges just to ensure some idealized vision of perfection.
103. A standard measure of market power is the Lerner index (L) or price-cost margin, defined as
- $$L = \frac{P - MC}{P}$$
- where P is the prevailing price and MC is marginal cost. If $L = 0$, then price equals marginal cost, as we would see in a perfectly competitive market. If a firm has a monopoly, the standard result is
- $$\frac{P - MC}{P} = \frac{1}{e_d},$$
- where e_d is the absolute value of the elasticity of demand for the monopolist’s product.
104. F. Wolak, R. Nordhaus, and C. Shapiro, “The Competitiveness of the California Energy and Ancillary Services Markets,” California ISO, March 2000.
105. S. Borenstein, J. Bushnell and F. Wolak, “Diagnosing Market Power in California’s Deregulated Wholesale Electricity Market,” POWER Working Paper PWP-064, Aug. 2000, at www.ucei.berkeley.edu/ucei/PDF/pwp064.pdf.
106. In terms of measures of market power, a markup over the competitive price would be
- $$\frac{P - MC}{MC} = \frac{L}{1 - L},$$
- where L is the Lerner index defined in n. 103 *supra*.
107. S. Puller, “Pricing and Firm Conduct in California’s Deregulated Energy Market,” POWER Working Paper PWP-080, Jan. 2001, at www.ucei.berkeley.edu/ucei/PDF/pwp080.pdf.
108. The *unilateral effects* and *coordinated interaction* nomenclature and definitions come from the U.S. Department of Justice and Federal Trade Commission, “Horizontal Merger Guidelines” (revised April 8, 1997), which can be found at www.usdoj.gov/atr/public/guidelines/horiz_book/hmg1.html. Some game-theoretic models, relying on repeated interactions, support collusive outcomes. However, these supergame models suffer from two flaws. One is the multiplicity of equilibria: they can support virtually any outcome in which everyone does better than they do under competition—the so-called folk theorem. J. Tirole, *The Theory of Industrial Organization*, Cambridge, MA: MIT Press, 1989, 246.
- A second less-noted flaw is that the equilibria require that firms change tactics based on what has happened in the past, without any learning or change in information. This assumption violates the fundamental economic principle that “sunk costs don’t matter,” that is, that economic agents’ perspectives are purely forward-looking, given present information.
109. *State of California v. Dynegy Power Marketing, and others*, Superior Court of the State of California, County of San Francisco (filed Jan. 18, 2001).
110. *Id.* at 7.

111. A standard result is that if we have N identical sellers in a market where the absolute value of the elasticity of demand is e_d , the Lerner index will be given by

$$\frac{P - MC}{P} = \frac{1}{Ne_d},$$

112. More generally, the Cournot price–cost margin when firms have different marginal costs is given by

$$\frac{P - MC^*}{P} = \frac{HHI}{e_d},$$

where MC^* is the share-weighted marginal cost of the sellers and HHI , the Herfindahl–Hirschman index, is the sum of the squares of the market shares of the sellers. If the shares are expressed as percentages, then the HHI becomes a number between 0 (atomistic) and 10,000 (monopoly), in which case it should be divided by 10,000 before being used to estimate price–cost margins.

113. Landes and Posner (“Market Power in Antitrust Cases,” *Harvard Law Review* 94, 1981, 937–996) have shown that in such a setting,

$$\frac{P - MC^*}{P} = \frac{S}{e_d + [1-S] e_s},$$

where S is the firm’s share of the market and e_s is the elasticity of supply of the other suppliers.

114. Note also that during peak periods, congested transmission lines may preclude supply from generators outside a region. In such “load pockets,” the elasticity of supply (and number of independent competitors, in the Cournot model) would fall.

115. Calculated from Joskow and Kahn, n. 55 *supra* at table 2, p.14.

116. FERC, Office of General Counsel, “Report on Plant Outages in the State of California,” Feb. 1, 2001, executive summary. The study left open the possibility that firms refused to supply electricity or bid some of it in at very high prices.

117. Market power questions aside, generators may engage in too little maintenance, with too many out-

ages, when the consequences of a power outage are borne over the entire grid and not merely by their customers. This is simply because the costs of an outage are borne across the grid and not only by the generator that fails unexpectedly. Outages, then, like anything else that produces negative externalities, will be too plentiful unless there is some way in which a generator that goes out bears the costs imposed on others from its outage. If the grid coordinator can cover the outage by procuring emergency reserve power, the generator could be sent the bill. If the outage leads to a blackout, calculating the bill and guaranteeing that the generator will pay it rather than go bankrupt are both more problematic.

118. See also F. Westfield, “Electric Power: Competition or Centralization,” *Energy Policy*, Aug. 1988, 378–383.

119. Again, compare hotel prices during high season with average operating costs. For a more fundamental illustration, imagine a market in which all sellers have the same technology, in which they can produce 10 units with a plant that costs \$20, where the per-unit marginal cost is \$3. If demand is substantial, that is, many multiples of 10, the equilibrium price in this market will be \$5 [$\$20 + 10(\$3)$]/10, not \$3. The correct Lerner index would not be 40% [$(\$5 - \$3)/\$5$], but 0.

120. A complicating factor here is that the PX took bids on an hour-by-hour basis. It is usually expensive to start up and shut down generators, so bids will not reflect the (relatively) simple marginal cost of running a plant for an hour. Bids could be higher at some times to reflect the costs of starting up, and perhaps lower at other times to reflect the opportunity costs of shutting down and having to restart later.

121. Long-term contracts also make collusion more difficult. Set through bilateral negotiations, they make “cheating” on the cartel more likely by making prices less public. Selling a large amount of power under a long-term contract also increases

the potential reward for undercutting the monopoly price. For more detail on the effects of “lumpiness” of orders and secrecy on inhibiting oligopolistic coordination, see F. M. Scherer and S. Ross, *Industrial Market Structure and Economics Performance*, Boston, MA: Houghton Mifflin, 1990, 306–311.

122. For an empirical argument that economies of scale in electricity power generation may be substantial, see T. Considine, “Cost Structures for Fossil Fuel-Fired Electric Power Generation,” *Energy Journal* 21, no. 2, 2000, p. 83.
123. The Clinton administration’s Comprehensive Electricity Competition Plan included such proposals. See statement on “consumer issues” at www.hr.doe.gov/electric/consumer.htm.
124. The National Association of Regulatory Utility Commissioners (NARUC) has developed its own proposals regarding consumer protection and marketing practices. See NARUC, “Codes of Conduct Governing Competitive Market Developments in the Energy Industry: An Analysis of Regulatory Actions,” at www.naruc.org/Resolutions/2000_conv/codes_of_conduct_white_paper.htm.

Another lesson from telecommunications that challenges economic analysis is whether consumers prefer to choose or to let their government do their shopping for them, despite the possibility that competition could work.

125. We ignore here the issues associate with “stranded cost” recovery, as perhaps warranted by the implicit regulatory contract. For a discussion of how such contracts might be interpreted, see Brennan and Boyd, n. 88 *supra*. The California experience suggests that the transfer of inframarginal rents to generators may accelerate cost recovery, reducing the need for additional stranded cost recovery going forward.
126. A suspicion that cannot be proven here is that generator anticipation of supply crunches and high

prices provided some political influence that accelerated restructuring.

127. Real-time pricing could be implemented along with regulations that kept rates low during off-peak periods. S. Borenstein, “Frequently Asked Questions about Implementing Real-Time Electricity Pricing in California for Summer 2001,” University of California Energy Institute, March 2001, at www-path.eecs.berkeley.edu/ucci/PDF/faq.pdf.
128. Regulated prices below cost provided a rationale for demand-side management programs before opening markets. See Brennan, n. 15 *supra*.
129. This idea is attributable to Frank Wolak.
130. For a review of these possibilities, see T. Brennan and K. Palmer, “Not Enough Anarchy in the U.K.” *Regulation* 21, Spring 1998, 2–3.
131. Notable exceptions are the reviews of regulatory and deregulatory outcomes from C. Winston, “Economic Deregulation: Days of Reckoning for Microeconomists,” *Journal of Economic Literature* 31, 1993, 1263–1289, and W. Harrington, R. Morgenstern, and P. Nelson, “On the Accuracy of Regulatory Cost Estimates,” *Journal of Policy Analysis and Management* 19, 2000, 297–322.

Appendix

Estimating the benefits of real-time metering

Suppose, as with peak electricity prices, that the peak-period price of electricity is below the price at which supply would equal demand. The benefits of peak-load pricing depend first on whether the suppliers are obliged to meet all demand, or whether the amount generators are willing to supply at the current price is rationed among the buyers.

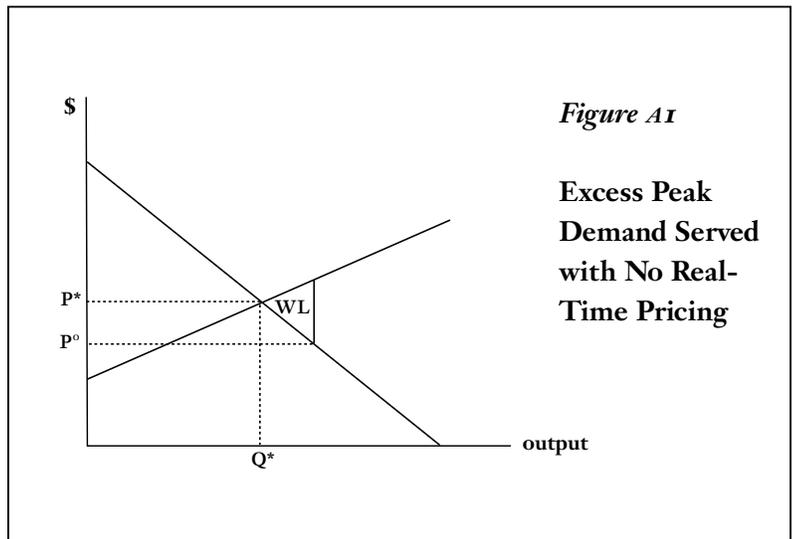
Suppose first the demand is not rationed, for example, because regulators force distribution companies to serve all customers even if they take a loss in doing so. Such a situation is illustrated in Figure A1.

P^* is the market-clearing price; P^o is the price imposed because of the inability to meter demand in such a way as to find and set P^* . The peak-demand welfare losses from the lack of real-time metering are indicated by the triangle WL . An approximate measure of the size of the welfare loss is

$$WL \approx - [\% \Delta P]^2 P^* Q^* \left[\frac{e_d}{e_s} (e_d + e_s) \right]$$

where

$$\% \Delta P = \frac{P^* - P^o}{P^*}$$



is the percentage reduction of the price below, P^* , the market clearing price, P^o is the price imposed because of the inability to meter demand in such a way as to find and set P^* , Q^* is the quantity demanded at P^* , e_d is (the absolute value of) the elasticity of demand, e_s is the elasticity of supply. The greater the welfare loss, the greater the elasticity of demand and the lower the elasticity of supply. The former is not likely for electricity, but the latter is. However, if both elasticities are small and roughly equal, the expression in the rightmost brackets will also be small.

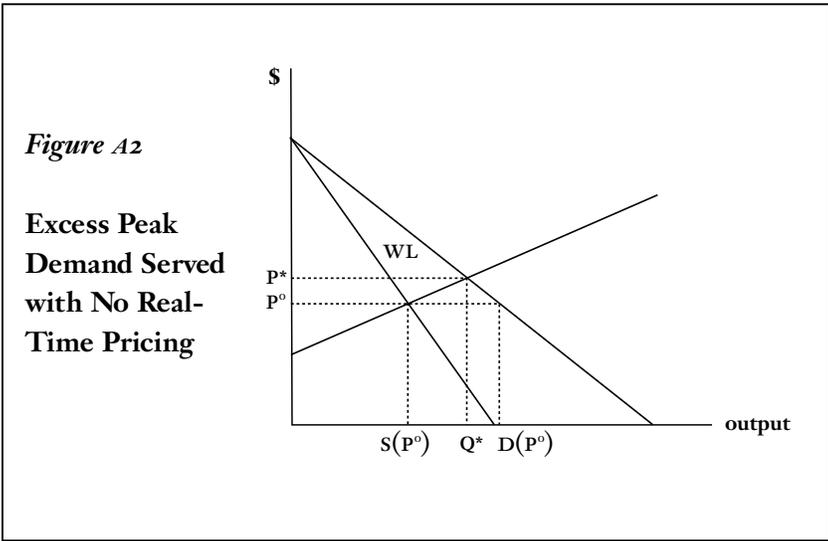
Using a similar diagram, we can show that when the sellers ration the output they would supply at P^o over the demand at P^o , the welfare loss will be approximately, at minimum,

$$WL \approx 1/2 [\% \Delta P]^2 P^* Q^* \left[\frac{e_d}{e_s} (e_d + e_s) \right]$$

This expression is almost the same as the other measure of welfare loss, except the supply and demand elasticities are reversed in the bracketed fraction. This is a minimum estimate of the welfare loss because it assumes that under rationing, the users who value electricity the most will obtain it. If each kilowatt demanded has an equal chance of being rationed, the welfare loss relative to the optimum will be approximately

$$WL \approx CS \left[\frac{D(P^0) - S(P^0)}{D(P^0)} \right] - \frac{1}{2} [\% \Delta P]^2 P^* Q^* [e_d + e_s]$$

where CS is the consumer surplus at P^0 , $D(P^0)$ is the quantity demanded at P^0 , and $S(P^0)$ is the quantity supplied at P^0 . The welfare loss is indicated in the area marked WL in Figure A2.



If the price divergence and elasticities are small, the right-most term will be small and the change in the consumer surplus itself will be a reasonable approximation.