Policy Analysis
No. 406 July 3, 2001

California's Electricity Crisis
What's Going On, Who's to Blame, and What to Do

by Jerry Taylor and Peter VanDoren

Executive Summary

The California electricity crisis threatens not only the economic well-being of ratepayers in California but the economic well-being of the United States as well. Unfortunately, the political and economic commentary surrounding the crisis is shedding more heat than light.

California has been victimized by several simultaneous and severe supply and demand shocks—most notably, a run-up in wholesale natural gas prices—that are outside the state's political control. Those shocks were made more severe by air pollution regulations and retail price controls. Although California's "deregulation" of the electric utility business is being blamed for the crisis by both the political left and the political right, we find that the 1996 restructuring law has little to do with the run-up in wholesale power prices. That law is primarily responsible for the blackouts, however, in that it prohibits utilities from passing on increases in fuel costs to consumers.

Virtually all the increase in wholesale prices can be explained by increases in production costs and overall scarcity. While there is some evidence of the existence of excessive generator "market power" (created not by the unfettered exercise of free markets but by poorly conceived regulation), it is relatively minor and responsible for only a small fraction of the price spike, if it exists at all.

We find little evidence to support the argument that environmentalists are primarily to blame for the crisis. We likewise are unconvinced that, had the state allowed utilities to enter into long-term contracts with generators, the crisis could have been either averted or made less severe.

None of the remedies thus far proposed—such as a state takeover of the industry, the so-far minimal increase in power rates, energy conservation subsidies, prohibitions of "wasteful" energy use, more vigorous wholesale price controls, or the adoption of long-term power contracts with generators—will get the state through the next two years without frequent and widespread blackouts and significant economic damage. In fact, all of those alleged remedies would make matters worse.

The only remedy to the crisis is the elimination of the retail rate cap and the institution of real-time pricing mechanisms for the largest segment of demand possible.

Jerry Taylor is director of natural resource studies at the Cato Institute. Peter VanDoren is editor of Cato's Regulation *magazine.*

While both sides are busily settling political scores, the real story of what happened in California is largely absent from most analyses.

Introduction

Skyrocketing wholesale power prices in California and the daily threat of brownouts and blackouts have cast a pall over the merits of electricity deregulation. Liberals, led by California's governor, Gray Davis, blame the restructuring law passed in 1996 for the crisis, arguing that it left the state vulnerable to market manipulation by greedy power producers. According to Davis, the crisis is largely artificial but nonetheless a harbinger of things to come, not only in national electricity markets but in industries throughout the economy, if we continue our mad rush toward laissez faire.

Conservatives for the most part agree that the 1996 reforms are primarily responsible for the crisis. They charge, however, that the regulations attached to those "reforms"—primarily the prohibition of long-term contracts between utilities and power generators and the imposition of a centralized daily spot market—are largely responsible for the price spike. The political right argues that California's regulations, crafted by environmental activists and anti-growth consumer groups, have long discouraged investment in new generating capacity and that the blackouts are a long-overdue flock of chickens coming home to roost.

While both sides are busily settling political scores, the real story of what happened in California is largely absent from most analyses. Accordingly, the important lessons that this crisis teaches about regulation and electricity are largely being overlooked: retail price controls are a recipe for disaster, and state regulators have little idea how to organize markets and certainly shouldn't attempt to do so under the mantle of "deregulation."

The Anatomy of California's "Deregulation"

On the last day of the 1996 legislative session, California's legislature adopted by unanimous vote A.B. 1890, the first of many state attempts to "deregulate" the electricity business. The roots of the confusion over what California *did* and *did not* deregulate began with the PR campaign to sell the bill. Unlike deregulation of the airline and trucking industries—which largely curtailed regulatory oversight of those industries—the "deregulation" of the electricity industry in California was heavily prescriptive and not, on balance, a loosening of regulatory oversight at all. A.B. 1890 simply replaced the old set of regulations with a new set of regulations, some of which were less interventionist than the old, some of which were more.

The central thrust of A.B. 1890 was to create a competitive retail market for electricity. Traditional rate-of-return regulation of state-sanctioned monopoly power companies had not kept electricity prices at reasonable levels. By the mid-1990s, California electricity prices were 35 percent higher than the U.S average, and California residential customers paid 35 percent more than the average U.S. residential customer.[1] Those excessive costs threatened to slow expansion in California and make the grid itself obsolete as ratepayers fled to nonutility power providers.[2]

The remedy was to allow competition among and free entry of electric generators. The generators owned by incumbent utilities would compete with nonutility power generators for business, and customers could choose from whom they wished to purchase power. Competition would protect consumers from the excessive investments and cost overruns that occurred under traditional cost-of-service regulation.

The Crusade against Market Power

While virtually all the nonutility interest groups endorsed this reform in principle, many of them—particularly the large industrial users of electricity, the independent power producers, and the "consumer rights" lobby—feared that incumbent utilities would use their control of the electricity grid (the incumbent-owned network of wood, steel, and wire that connects power plants to consumers) to disadvantage independent generators. Incumbent utilities would exclude independent generators from the grid, price access exorbitantly, or load the grid with their own power and thus use congestion to restrict entry. Or utilities could charge retail customers below-cost rates while recouping those losses through excessively high transmission and distribution rates for competitors. Because most analysts assume that the grid is a natural monopoly (building alternative grids is widely thought to be prohibitively costly and impossible politically because of fierce community resistance), it was feared that allowing nonutility firms to enter the generation market would not result in a competitive market for wholesale power.

Reformers thus concluded that electricity "deregulation" would require a whole new set of regulations and government interventions to ensure that a competitive market would arise. The important provisions of A.B. 1890 follow.[3]

- *Mandatory Open Access:* Utility companies must allow any generator access to the electricity transmission system under terms, conditions, and prices established by the state.
- *Vertical Disintegration:* Incumbent utilities are to become transmission and distribution companies, divesting themselves of generators. And the divested generators can sell power only to a state-managed power exchange.
- *Centralized Power Exchange:* Any electricity the incumbent utilities need for their default customers (those who do not switch to competitive suppliers under the retail choice program) has to be purchased from a centralized, state-managed power exchange. Independent marketers can buy through the exchange voluntarily. The exchange creates an electricity supply curve from generators' hourly willingness-to-produce offers. The hourly price is set by the highest-cost producer whose output is necessary to meet estimated demand from the utilities.
- *Utility Retail Price Caps:* For those customers who remain with the three incumbent utilities (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric), retail rates are frozen at levels 10 percent below June 1996 rates until the incumbent utilities recover their "stranded costs" or March 2002, whichever occurs first.
- *Independent System Operator (ISO):* The day-to-day operation of the grid (that is, the management of electricity traffic along the wires) is directed, not by the utilities that actually own the grid, but by a nonprofit organization governed by a 26-member advisory board of representatives of grid users. The ISO is further empowered to procure electricity on an emergency basis if on any given day the amount of power procured in the centralized power exchange is insufficient to meet demand.

"Stranded Costs" and Retail Price Controls

Although utilities were never particularly excited about the proposed change from traditional rate-of-return monopoly regulation to managed competition, they were particularly worried that, were they forced to compete with independent power generators in this new wholesale marketplace, some of their generating assets (nuclear power plants and long-term contracts with nonutility power producers) would not produce sufficient revenues to recover their total costs. This would reduce the market value of those assets to much less than their "book" value on the utilities' balance sheets. Electricity analysts coined the phrase "stranded costs" to describe the difference between book and market values of certain generating assets. In California, stranded costs were estimated to be between $21 billion and $25 billion.[4] Estimates for the United States ranged from $70 billion to $200 billion; the higher figure

Reformers concluded that electricity "deregulation" would require a whole new set of regulations and government interventions.

was double the total shareholders' equity in the industry.[5]

Utilities and several prominent academics justified recovery of those stranded costs by arguing that a "social contract" existed between investors in utilities and state regulators. In their view, the investors and the government agreed that, if the companies would serve all customers in an area as a state-sanctioned monopoly, the investors would receive a regulated but reasonable return on their investment.[6] Thus, deregulation without compensation of investors for the capital losses they suffer as a result breaches the contract. It "takes" investors' property without compensation—a violation of the Fifth Amendment's Takings Clause—and raises the cost of capital in any other sector of the economy in which potential changes in public policy create risk.

Economists disagree about whether stranded-cost recovery is either efficient or "fair."[7] Those who oppose stranded-cost recovery argue that investors surely know that the rules of the regulatory game are subject to change, and investors can and do take that into account when investing their money. You place your investment bets and you take your chances.[8]

Moreover, if taxpayers were constantly reimbursing businesspeople for investments that become less attractive once the rules of the game are changed, beneficial regulatory reforms might never occur. Furthermore, many of those stranded costs were enthusiastically embraced by the utilities at the time. Few utilities were dragged kicking and screaming into those costly investments; many utility executives wisely passed them by.

California and federal taxpayers pay for the rate relief in the form of tax receipts forgone because the interest is tax-exempt.

Nevertheless, A.B. 1890 allows recovery of utilities' stranded costs through the imposition of a mandatory "competitive transition charge" on all ratepayers. Of course, it would be hard to sell ratepayers on a deregulation scheme that raised rates in the short run via some incomprehensible "competitive transition charge." So A.B. 1890 imposes a rate freeze on industrial and large commercial utility customers and a 10 percent reduction in residential and small commercial utility rates. Those rate controls are to stay in place until a utility recoups its allotted share of stranded costs, or no later than March 2002.

How could the state mandate a rate cut and impose a "competitive transition charge" at the same time? Simple: it issued tax-exempt bonds through the off-budget California Infrastructure and Economic Development Bank to amortize the rate cut over a period of time longer than the period during which the rate cut was actually given to consumers. So California and federal taxpayers pay for the rate relief in the form of tax receipts forgone because the interest is tax-exempt.

The Mirage of Retail Choice

Under A.B. 1890, consumers not only enjoy a rate cut, they also are allowed to choose their power company in much the way they choose their long-distance telephone company. And the competition among electric generators is supposed to keep rates down. But A.B. 1890 sets the rate for default electric service from the incumbent utilities for the period 1998 to March 2002 at 10 percent less than the 1996 rate; the difference is to be paid for, in part, by the tax-exempt bonds. New independent firms have not been able to underprice this default service. Only 1 percent of California's residential ratepayers had switched suppliers by early 2000 despite large advertising investments by power marketers.[9] One of the leading power marketers, Enron, actually abandoned the California residential market after only three weeks because consumers had little incentive to leave their traditional suppliers. Competition was largely confined to the centralized power exchange, where nonutility firms competed in a mandatory day-before spot market to sell power—not directly to consumers but to the incumbent utilities acting as default suppliers to customers.

The Precrisis Market

Although the public may not have grasped exactly what A.B. 1890 was all about beyond some vague notion that "competition" was on the way because of deregulation, energy analysts were less certain that any of this would work. While most analysts felt that, on balance, the new regime would prove a valuable first step toward further deregulation, some, including the authors of this paper, seriously doubted it and wrote as much at the time.[10]

Still, California's electricity market under the new regime appeared to work reasonably well from April 1998 through the spring of 2000. Even though retail competition for electricity ratepayers never fully materialized because of the price controls on default service, wholesale electricity prices averaged $30 per megawatt-hour (MWh), or 3 cents per kilowatt-hour (kWh), in 1998 and 1999.[11] Those low prices allowed utilities to earn a return on sales and recover stranded costs even with the retail rate cap.[12] Between April 1998 and April 2000, when the wholesale cost was lower than the retail price cap, the three incumbent utilities retired $17 billion in debt.[13] Incumbent utilities were also able to recoup some stranded costs by selling fossil-fuel power generators with a total book value of $1.8 billion for a combined $3.1 billion retail price.[14]

Analysts did not predict that the crisis would occur.[15] University of California-Berkeley, economist Severin Borenstein, for example, remarked: "If we [economists] had understood better, we would have warned better. . . . There were many things we didn't see."[16] In its summer 2000 system reliability report, the North American Electricity Reliability Council estimated the reserve margin in the California-Mexico interconnection to be 15 percent over the estimated July peak demand, a larger reserve margin than in several other regions of the United States.[17] The assessment did warn that the region "may not have adequate resources to accommodate a widespread severe heat wave or higher than normal generator forced outages,"[18] but NERC was much more worried about the supply-demand imbalance in New York and New England than in California.[19] Even in March 2000 the California Energy Commission forecast a weighted-average price for 2000 of 2.85 cents per kWh and a peak monthly weighted-average price in September of 4.5 cents per kWh. The actual weighted-average prices were 11.3 cents per kWh for 2000, and the highest monthly average price was 37.2 cents per kWh in December.[20] And as late as November 2000 NERC argued in its 2000–01 winter assessment that generation in all regions would be able to meet demand should normal weather prevail.[21]

The Perfect Storm

California's happy state of regulatory affairs changed radically in 2000–01 when two large supply shocks and one large demand shock simultaneously hit the state. None of those shocks was triggered by state policy. All of them, however, had a serious impact on wholesale electricity prices.

Two large supply shocks and one large demand shock simultaneously hit the state. None of those shocks was triggered by state policy.

The Natural Gas Price Spiral

The first supply shock was a massive increase in regional wholesale prices for natural gas, the fuel input for 49 percent of California's electricity capacity in the first nine months of 2000[22] and nearly all its peaking capacity. In 1998–99 the average price of natural gas delivered to utilities in California was $2.70 per million British thermal units (Btu).[23] By the summer of 2000, however, wholesale spot gas prices at the southern California "gate" had risen to $5 per million Btu, and they had risen to an average of $25 per million Btu by December[24] (the price reached $60 per million Btu on December 9).[25]

The increase in natural gas prices was nationwide. Wholesale natural gas prices throughout the United States during November and December 2000 averaged nearly $10 per million Btu compared to $2 per million Btu during 1999.[26] Mark Mazur, acting administrator of the Energy Information Administration, testified to the Senate Energy and Natural Resources Committee that "gas prices previously had not remained this high for a sustained period of time."[27]

Pricing output as a weighted average of differing prices of inputs would result in shortages.

The increase in the price of natural gas was the logical consequence of the first significant cold winter after several mild winters and less-than-average amounts of natural gas available from storage.[28]

The price increase was worse in California because demand was greater relative to pipeline capacity and total storage.[29] An explosion in August 2000 shut down the El Paso pipeline, which carries natural gas from Texas to southern California. That accident reduced pipeline capacity into the state by 10 percent for several weeks, a large supply disruption that has not been fully remedied.[30]

The surge in demand and the subsequent price increase caught the industry by surprise. Natural gas prices had, after all, declined 25 percent in inflation-adjusted terms between 1985 and 1999.[31] Consumption from 1995 through 1999 was essentially flat.[32] Thus there were very limited incentives to increase production or hold inventory going into 2000.

With the increase in prices, however, the oil and gas industry increased domestic exploration and development budgets by 40 percent in 2000; another 20 percent increase is expected in 2001.[33] Unfortunately, new investments in production will increase output only after several years. The Energy Information Administration, a semi-independent analytic arm of the U.S. Department of Energy, believes that prices will resume their historical trend by 2004.[34] The National Petroleum Council concurs, forecasting that the average wellhead price through 2010 will be approximately $2.74 per million Btu.[35]

Given that 90 percent of a natural gas–fired generator's cost of producing electricity stems from fuel costs,[36] increased natural gas costs must increase electricity prices. A natural gas price of $20 per million Btu, for example, translates into a production cost of at least 20 cents per kWh for an average natural gas–fired plant and 32 cents per kWh for the least-efficient power plants.[37]

Why Natural Gas–Fired Electricity Determines Wholesale Prices

The least-efficient plants' costs are relevant because in commodity markets, like electricity, the costs of the most costly producer whose output is necessary to meet aggregate demand set the price for all the electricity sold, even power produced from other fuels. Thus, the California wholesale market cannot be understood without a full understanding of the increased cost of gas–fired electricity.

This is doubly important because many commentators have argued that, if utilities had signed long-term contracts with cheaper sources of power, the price spiral would have been less dramatic. Underlying that argument is the belief that the price of electricity in a free market would be a weighted average of long-term and spot prices.[38] While this belief has superficial plausibility, pricing output as a weighted average of differing prices of inputs would result in shortages.

Imagine that supermarket lettuce prices were different depending on individual farmers' costs. Once people realized that different prices existed for lettuce, shoppers would snap up the low-cost lettuce first. The supermarket would then ask the low-cost lettuce producer for more output at lower prices. But could the lettuce producer easily expand output at the same low costs? He could if he didn't have to pay market prices for additional inputs, but that would be the case only if he had additional inputs under long-term contract. And if he or other producers had such spare capacity lying around under contract, market prices would already have decreased to reflect the competition among the owners of excess supply to use the units for which they had contracted.

If the low-cost producer did not have spare capacity under long-term contract and had to pay market prices for additional inputs like land and fertilizer, he would have to charge higher prices for the additional output to cover costs. In addition, the low-cost lettuce producer would realize that, rather than increase output at higher prices, he could raise prices on his existing low-cost output, eliminate the shortages, make more money than if he used weighted-average pricing, and not have to increase production.

Electricity markets are analogous to the lettuce example.[39] Even if California utilities had contracted for 99 percent of their supply at low prices, demand would exceed supply at those prices. And if the utilities attempted to expand output, they would have to pay market prices for the fuel input and would lose money on every additional sale unless the additional output was sold at market prices.

Thus, uniform prices for all sources of electricity regardless of their respective input costs is a (good) characteristic of free markets and not the result of the prohibition of long-term contracts in the California system or of the mandate that transactions take place through a centralized spot market. In fact, this very point was once made quite energetically by the political left to justify energy conservation subsidies. Amory Lovins, a famous advocate of energy conservation, has argued correctly that traditional state regulation of the electric utility business delivered average costs, not marginal costs, to ratepayers, which resulted in economically inefficient (excessive) levels of consumption and losses for the utilities whenever marginal costs exceeded average costs.[40] Lovins's remedy for this market distortion, however, was not a "first-best" solution—the introduction of marginal cost pricing—but a "second-best solution"—to have electric utilities subsidize ratepayer purchases of energy efficient appliances and technologies, which would be cheaper for utilities than investments in additional generation (a matter we'll return to later in this paper).

The Weather

The second supply shock was caused by a three-year dry spell that reduced reservoir and river-flow levels and thus reduced hydroelectric generation in California by 20 percent from 1998 to 1999.[41] In addition, before 1998 hydropower was more abundant than normal, reducing the returns that would come from investment in natural gas–fired production, just as California was switching to "deregulated" generation. Hydro output in the Canadian and U.S. West in 1997 was more than 30 percent greater than in 1992.[42] Hydropower from the Pacific Northwest further declined from an hourly average of 20,805 megawatts (MW) in 1999 to 18,075 MW in 2000. California hydropower likewise declined from an hourly average of 4,395 MW in 1999 to 2,616 MW in 2000.[43] From June through September 2000, hydro production throughout the West was, on average, 6,000 MW less than during the same months in 1999, equivalent to the output of 7 to 10 nuclear plants.[44]

Unfortunately, the water shortage will almost certainly get worse before it gets better. Stream flows in the Pacific Northwest last January were only about 60 percent of average[45] and snowpack in the Cascade Range was likewise only 60 percent of normal,[46] prompting the Northwest Power Planning Council to warn that hydroelectric power generation this summer will be 5,000 MW below normal.[47] As of March 30, 2001, California's Department of Water Resources reported that snow and rain accumulation was 34 percent less than normal in that state.[48] The practical effect of this reduction in hydroelectric generation was to leave California with little spare generating capacity during peak-demand periods.

In addition to the negative supply shocks (natural gas price increase and hydro shortage), a demand shock hit during the summer of 2000 because of unseasonably warm temperatures (a 13 percent increase in cooling degree-days across the Pacific region from 1999 to 2000).[49] Temperatures in the Arizona subregion of the western grid averaged three to five degrees higher than normal.[50] The California-Nevada subregion of the western grid experienced the 99th hottest summer of the last 106 in June 2000, compared with 59th and 14th in 1999 and 1998, respectively.[51]

Accordingly, energy consumption and average daily loads during the summer of 2000 grew rapidly compared with the same period in 1999. Electricity consumption in the western states, excluding California, increased by 4.7 percent in from May 1999 to

The second supply shock was caused by a three-year dry spell that reduced reservoir and river-flow levels and thus reduced hydroelectric generation in California.

No regulatory system could have prevented wholesale electricity prices from climbing to record levels under these circumstances.

May 2000, and energy consumption in California increased by 5.8 percent over the same period. The increase in energy consumption from June 1999 to June 2000 was even greater—7.3 percent for the Western Systems Coordinating Council states, excluding California, and 13.7 percent for California. Within the ISO, average daily peak loads grew by 11 percent in May and 13 percent in June compared with the same months of 1999.[52]

Even though the increase in electricity demand may not sound dramatic, the effect on natural gas consumption was dramatic because of the hydropower reductions. During May–September 2000, natural gas consumption in California by utilities was 22.4 percent greater than for the same months in 1999.[53] In the West as a whole natural gas use for electricity generation increased an astonishing 62 percent during the same period.[54]

The hot summer of 2000 was then followed by a historically cold winter in 2001, ensuring that demand would remain high throughout the region.[55]

Some commentators have questioned whether this seemingly moderate increase in demand could really explain price increases that are severalfold more severe on a percentage basis than the increase in demand.[56] Given the relative inelasticity of demand for electricity in general (made worse by the existence of retail rate caps, discussed below), even moderate increases in demand will increase prices dramatically if supply is fixed in the short term, which is exactly what has happened in the western power market.[57]

We draw two conclusions from our analysis of supply and demand changes in California. First, the reductions in supply and increases in demand that resulted in wholesale electricity price increases are the result of natural weather variation interacting with market forces.[58] No state politician, regulator, or businessman could have headed them off. Second, no regulatory system—not the pre-1996 regulatory regime, not the post-1996 regulatory regime, not a completely laissez faire regime, and certainly not any of the various regulatory regimes put in place in other states—could have prevented wholesale electricity prices from climbing to record levels under these circumstances.

Political Cloud Seeding

While we believe that the hydro shortage, natural gas price increases, weather shocks, and pipeline disruptions are the proximate causes of increased prices for wholesale electricity in California—“the perfect storm,” if you will—the price increases were exacerbated by the existence of two politically created phenomena: nitrogen oxide (NO_X) emission permits and retail price controls. That “political cloud seeding” made the perfect storm even more intense and unpleasant.

NO_X Emission Permits

Although environmental regulations, in general, affect both generating costs and the ability to site new capacity, California’s requirement that generators have sufficient NO_X emissions credits before going online played a particularly important role in the price spiral of 2000–01. “To the extent there is a smoking gun, it’s NO_X,” J. Stuart Ryan, vice president of AES Pacific, an independent power generator, told the Federal Energy Regulatory Commission. “The cost of credits for NO_X emissions in the L.A. Basin has skyrocketed.”[59]

It is well understood that NO_X emissions are often (but not always) an important contributor to urban smog in the summertime.[60] Accordingly, California adopted regulations in 1994 (known as the RECLAIM program) that allotted a certain number of NO_X emissions credits to existing emissions sources in southern California and allowed them to trade those credits on the open market so that the overall costs of emission reduction across plants would be minimized. Plants that found it cheaper to buy emissions permits than to reduce facility emissions would purchase permits from firms that found it cheaper to reduce emissions than to hold emissions permits. Each year the pool of credits is reduced by 8 percent. Power generators must purchase enough credits to offset emissions before they can go online or pay large fines to the state.[61]

In the winter of 1999, NO_x credits were selling for about $2 per pound. By the summer of 2000, those same credits were selling for $30 to $40 per pound where they have stayed ever since.[62] Because an efficient gas–fired plant emits about a pound of NO_x per MWh and an inefficient plant emits about two, NO_x credit prices of $30 to $40 per pound necessitate an additional cost of $40 to $80 per MWh ($0.04 to $0.08 per kWh).[63] In January 2001, California regulators initiated a waiver of NO_x permit requirements for power generators for the next three years, but the damage had been done.[64]

Although it's true that the RECLAIM program affects only those generators in the L.A. Basin—the source of only a fraction of the state's power—remember that the highest-cost source of electricity sets the price for *all* electricity sold through the western grid. Aaron Thomas, a manager at AES Pacific, points out that generators in the L.A. Basin "are setting the clearing price for everybody in California. And to the extent that that market is influencing markets in the West, all of a sudden you're getting these basin units driving costs for 50 million people in the West."[65]

The Damage from Price Controls

The wholesale electricity price increases in California were exacerbated by the existence of retail price controls.[66] Normally, firms that increase prices experience fewer sales as a consequence. With retail price controls, however, power generators could increase prices without fear that those price increases would reduce revenue.

Academic economists have tested this proposition. Vernon Smith and his colleagues at the University of Arizona have conducted experiments to compare the behavior of auction prices under two scenarios: one in which consumers face rigid retail prices and a second in which 16 percent of customers face real prices that reflect supplier bids. Prices in the second scenario are as much as 30 percent less than prices in the first scenario. Prices are dramatically lower as long as some customers face the real costs of peak-demand electricity.[67] Industry consultant Eric Hirst argues that if only 20 percent of the total retail demand faced hourly prices, and as a response to those prices reduced demand by 20 percent, the resulting 4 percent drop in aggregate demand could cut hourly prices by almost 50 percent.[68]

In addition to the lack of demand responsiveness created by the price controls, the ISO places an infinite value on "keeping the grid up," which exacerbates the problem. As wholesale prices increased after May 2000, the ISO enacted price controls in the market for daily backup and load-following (ancillary) reserves. On June 28, 2000, prices were limited to 50 cents per kWh and on August 7, 2000, to 25 cents per kWh.[69] On November 1 FERC issued a "soft" price cap of 15 cents per kWh for both the California day-ahead power exchange and the real-time and ancillary ISO markets.[70] Given our analysis of the effects of the prices of natural gas and NO_x permits on the marginal costs of the least-efficient natural gas–fired generators, the price ceilings had the practical effect of driving backup and load-following peak-demand generators out of the market.

FERC data support this conclusion. The commission reports that out-of-state generators reduced their sales to California from May through August 2000 relative to May through August 1999 by an average of 3,000 MW a day and their sales to the daily market operated by the ISO by 2,000 MW a day.[71] Tom Williams, an executive at Duke Energy, confirmed that those price caps discouraged the company from selling power in California during peak-demand periods, further shortening supply on the day-before market.[72]

But the ISO still had the responsibility to keep the grid operating and had to ask those same generators to supply on an emergency basis regardless of price. In January 2001, for

If only 20 percent of the total retail demand faced hourly prices, the resulting 4 percent drop in aggregate demand could cut hourly prices by almost 50 percent.

example, the ISO paid $461 million for last-minute purchases whereas in January 2000 the ISO spent only $2.7 million on last-minute grid support. The price controls combined with unlimited willingness to pay for emergency power on the part of the ISO induced high-cost suppliers to stay out of the day-before market operated by the power exchange and hope for emergency calls from the ISO at very high prices. A vignette in the *New York Times* illustrates the problem:

> With its employees focused solely on keeping the lights on—and with the bills to be paid not by itself but by the utilities—critics say the agency was ripe to be outfoxed by power suppliers.
>
> "My people are not trained as traders or arbitrageurs," conceded Jim McIntosh, director of scheduling for the system operator.
>
> When traders were asking $2,000 for a megawatt-hour of electricity, enough to light 1,000 typical homes for an hour, Mr. McIntosh and one of his bosses refused.
>
> But the price they settled on—$1,500—was arbitrary, Mr. McIntosh acknowledged.[73]

Moreover, as the fiscal plight of the utilities became public knowledge (a plight entirely caused by retail price controls that prevented the utilities from raising enough revenue to pay for electricity from the state power exchange), some generators left the market out of fear that the IOUs they were receiving from the utilities would never be repaid. The California ISO, for instance, reports that the March blackout was largely caused by generators' shutting down 2,000 MW of production because they had not been paid for the power they sold to the utilities for three or four months.[74]

The political and financial uncertainties of doing business in California have driven up the prices that generators charge for power.

Other generators reflected the risk of nonpayment in the prices they charged the state. Gary Ackerman, executive director of the Western Power Trading Forum (a trade group representing western power generators), forthrightly acknowledges that the political and financial uncertainties of doing business in California have driven up the prices that forum members charge for power.[75] Duke Energy confirms Ackerman's assertion, acknowledging that the prices it charged California utilities included a credit premium to cover the risk of nonpayment.[76]

Pacific Gas & Electric agrees. The company alleges that on January 18, for instance, six suppliers that had provided 36 percent of its daily supply had stopped service to the utility or threatened to do so. PG&E later lost more suppliers that had provided another 30 percent of supply.[77] And on March 19 about half of the capacity of independent power producers (3,100 MW) who had contracts to supply the incumbent utilities was shut down because of nonpayment.[78] In light of PG&E's bankruptcy on April 6, 2001, that behavior seems very prudent.

Explaining the Blackouts

In a free market, reductions in supply do not result in shortages because prices increase enough to equate supply and demand. Higher prices induce firms to create additional supply as quickly as possible to obtain profits. Eventually, the high prices eliminate the shock.

Wholesale electricity prices in California since the spring of 2000 have averaged more than 15 cents per kWh.[79] Retail electricity prices, however, were capped at less than 7 cents per kWh. Wholesale prices signaled that electricity was increasingly scarce, but retail prices told consumers that nothing had changed. Accordingly, consumers demanded more electricity than was available. Blackouts are the inevitable result of attempts to regulate and legislate basic economic laws out of existence.

Unexpected shortfalls in transmission capacity also have contributed to the blackouts. The main transmission line between northern and southern California (Path 15) has at times been limited to half its normal capacity, significantly complicating northern California's power supply;

thus the rolling blackouts have been confined largely to that region.[80]

Market Manipulation and "Price Gouging"

Do supply and demand shocks fully explain high California electricity prices? Industry analyst Edward Krapels believes that supply and demand shocks explain the December 2000 wholesale price in California but do not explain 5 cents per kWh of the average April through November price.[81] MIT's Paul Joskow and economic consultant Edward Kahn also conclude that "high wholesale prices observed in summer 2000 cannot be explained as the natural outcome of 'market fundamentals' in competitive markets since there is a very significant gap between actual market prices and competitive benchmark prices . . . high prices experienced in the summer of 2000 reflect the withholding of supplies from the market by suppliers."[82]

Where Did All the Power Go?

Californians served by the ISO typically demand 45,000 MW of electricity during peak periods in the summer, and that electricity was available during the summer of 2000. By contrast, Californians served by the ISO demand only about 30,000 MW during peak periods in the winter. How could 15,000 MW of power disappear and result in blackouts during the winter of 2000–01?

One answer, of course, is that it was sold to other markets in which wholesale price caps are not in place. The $250 per MWh wholesale price cap established by the ISO in August was below the marginal costs of the least-efficient natural gas units with the greatest NO_x emissions in the Los Angeles Basin. A number of power generators simply stopped producing as soon as the cap was put in place.[83]

Another possible explanation is that the hydropower that was lost during the summer of 2000 was replaced by many old natural gas units that postponed needed maintenance and repairs until this winter.[84] Approximately 65 percent of the state's generating capacity, after all, is in plants 35 years old or older.[85] This is particularly the case with the plants used to meet summer peak demand. Those gas–fired plants seldom operated steadily until the summer of 2000, and, because they are older and more inefficient, they require additional repair and upkeep. At various times during the winter of 2000–01 power plants were out of service in unprecedented numbers.[86] During the first blackout on January 17, for instance, fully 11,000 MW of in-state capacity was offline for repair and maintenance work.[87]

Disbelief of the repair-and-maintenance argument is rampant. Harvey Rosenfield and Doug Heller of the Foundation for Taxpayer and Consumer Rights call for state agents to "obtain search warrants and subpoenas to enter the power plants to determine the true cause of the shortages. If necessary, the plants should be seized to protect the public health and safety."[88] Of course, it's unlikely that such investigations would unearth the equivalent of a smoking gun. After all, companies are more than capable of justifying maintenance work. An investigation by FERC found that "generating outages in California at plants owned by Dynergy, NRG, and Reliant appeared to stem from increased demand and age of the units (boiler tube and seal leaks, turbine blade wear, valve and pump motor failures, etc.)."[89]

Economists are divided about the role of market power in explaining the behavior of California electricity markets.[90] Using publicly available estimates of the heat rates of electric generators and natural gas price data, Severin Borenstein, James Bushnell, and Frank Wolak from the Universities of California-Berkeley and Stanford generated estimates of the marginal costs of electricity. They then compared those estimates with actual prices observed on the California Power Exchange. They argue that the exercise of market power raised California electricity prices at least 16 percent above the competitive level (marginal cost) from June 1998

Supply and demand shocks explain the December 2000 wholesale price in California but do not explain 5 cents per kWh of the average April through November price.

Generators had the incentive to offer a small amount of their output at very high prices because, if the high bid was accepted, they would receive that price for all their output.

through September 1999.[91] Joskow and Kahn studied the summer 2000 California market and concluded that an inordinate number of plants were taken offline for maintenance when the price spikes were most intense. While that could be coincidence, it would also be perfectly consistent with market power: the withholding of some units of production to raise the price of electricity produced by other units owned by the same firm.[92]

An Alternative Explanation: Regulatory Perversity

But Harvard's Bill Hogan and Scott Harvey of LECG, a consulting firm, argue that generators in California priced above marginal cost, not because they had market power, but because two characteristics of the California market created incentives for them to place high bids.[93] The California market solicited hourly bids from all generators a day in advance of production. In addition, once the day-ahead market cleared and produced hourly prices, the ISO asked for bids for reserve power. Under ideal conditions, arbitrage would result in similar prices for day-ahead and reserve energy in each hour, but because the ISO auction was conducted after the power-exchange auction, uncertainty existed about whether a generator would receive a higher price if it waited for the ISO to call on a unit as a reserve unit. This sequential feature converted the day-ahead auction from an everyone-gets-the-market-price auction (and thus generators would bid at marginal cost to ensure being selected to produce as long as costs were covered) to a pay-as-you-bid auction in which all participants, if selected, receive what they bid rather than the (potentially) higher market-clearing price.

Under such a market structure, firms lacking market power will bid at expected market-clearing prices rather than at marginal cost.[94] And market-clearing prices for the reserve market during a capacity shortage in which retail consumers do not face high prices will be very high indeed because under the engineering procedures developed by the NERC, electric system operators such as the ISO must maintain generation reserves available in 10 minutes regardless of cost.[95] Producers have no reason *not* to name a stratospheric price for their power in those circumstances because the price they charge will not alter demand (remember, retail prices are capped and, even were they not, ratepayers face lagged-average rather than real-time marginal prices for electricity). As University of California-Berkeley economist Steven Stoft puts it, "The failure of consumers to respond [because of price controls] is the fundamental flaw that makes prices reach exorbitant levels when there is a little scarcity or when suppliers have even a little market power."[96]

University of Maryland and Resources for the Future economist Tim Brennan argues that another characteristic of the California auction market also created incentives for high rather than low market-clearing prices.[97] The rules of the auction allowed generators to offer different amounts of electricity at different prices rather than all of their output at one price. Under those rules, generators had the incentive to offer a small amount of their output at very high prices because, if the high bid was accepted, they would receive that price for all their output. And if the bid was not accepted, the generators would lose only the sale of a small fraction of their possible output. Normally such bidding behavior would be unprofitable because the probability of the high bid's being accepted would be small, but, in a very tight supply situation, the probability of the bid's being accepted rises considerably, and the opportunity cost of the unsold power falls.

"Price Gouging" in Perspective

Even though perverse behavior by electric generators—induced either by actual withholding or by characteristics of the California auction—may have played some role in the price spike, the populist charge that the entire price spike can be explained by producer manipulation is clearly nonsensical.[98]

Input costs and natural scarcities are responsible for most of the price hike. Some of the top economists in the electricity "establishment"—individuals on both sides of the dispute—agree that, although market manipulation may be present, it is not the fundamental cause of the crisis.[99]

Consider the data available on wholesale prices in January and February 2001. FERC maintains that it cost 27 cents, on average, to produce a kilowatt-hour of electricity in natural gas–fired generators during stage 3 emergencies in California last January.[100] The California ISO reported, however, that it paid an average of just over 28 cents for power purchased in the real-time spot market.[101] During February, wholesale natural gas prices increased dramatically, resulting in FERC estimates of production costs of 43 cents per kilowatt-hour during stage 3 emergencies.[102] Unfortunately, there are no published data that allow a comparison of the FERC estimate and actual prices observed in the real-time spot market, but if the January relationship held in February, wholesale prices were not more than a few cents higher, on average, than production costs.

To be sure, industry analysts believe that actual production costs during power emergencies are far higher than FERC believes—largely because FERC relies on a monthly average for wholesale natural gas prices that inadequately reflects day-to-day price changes,[103] but at least FERC has recognized that input prices and the NO_x quantity restrictions explain most of the price increase and that the highest-cost source of supply necessary to meet demand sets the legitimate price for all power sold in the market.[104]

Big Profits? Big Deal

The evidence most commonly used to justify charges of price gouging is the huge profits earned by many independent power generators doing business in California. California Senate president pro tem John Burton, for instance, supports his charge of price gouging by noting that power generators and power marketers have seen their profits rise by an average of 508 percent over the past year.[105] But large profit margins are not themselves evidence of prices above marginal costs of the most-expensive unit.

The key to understanding the electricity market is, again, to remember that the highest-cost source of supply necessary to meet demand sets the price for all electricity in the marketplace. Thus, inframarginal generators—such as those who have access to cheap gas through long-term contracts or who have highly efficient power plants—can and do sell at the market-clearing price and make profits (a state of affairs that is found satisfactory by both FERC and the California ISO). Marginal generators—those who have no access to cheap gas or who operate old, inefficient plants—have no such market advantages and thus fewer profit opportunities. The profits reported in the media largely reflect the profits made by inframarginal, not marginal, producers.

Are Environmentalists the Culprit?

Many observers have argued that the California electricity shortage is the result of environmentalists' and consumer activists' efforts to block new generation and transmission capacity, slowly starving the state of needed power.[106] California's reserve generating capacity decreased from 40 percent in 1990 to 15 percent at the beginning of 2000.[107] Last summer, demand for electricity was up 23 percent compared to 1992, yet generating capacity had grown by only 6 percent.[108]

A Murder with No Body?

Although it's certainly true that California has not seen a boom in power plant construction over the past decade, the claim that no new power plant has been built in California in more than 10 years is utterly false. According to the California Energy Commission, 11 power plants (10 gas fired, 1 coal fired) with a generating capacity of 1,206 MW began operation in California in the 1990s.[109]

Although market manipulation may be present, it is not the fundamental cause of the crisis.

Obvious explanations for the lack of investment in new capacity are low prices and regulatory uncertainty.

Only two licensed projects with a generating capacity of 229 MW were dropped in the 1990s (one because of bankruptcy), and only one project was blocked by community activists: a 240 MW set of barge-mounted generators that were to supply peaking capacity to the San Francisco Bay area.

Opposition to new power plants is not confined to environmentalists, and some environmental groups actually support new plants. The Calpine Co. has proposed building a 600 MW gas–fired plant in San Jose. Many environmental groups, including the Sierra Club, actively support the plant. The main opponent, ironically, is the Internet giant Cisco Systems, which fears that a power plant near its facilities would be aesthetically unpleasing and thus reduce its ability to attract employees.[110]

Not only were environmentalists a relative nonfactor in generator investment decisions in the early to mid-1990s, they scarcely played any role in blocking new capacity in the months leading up to the crisis. Since Governor Davis was elected in 1998, California has approved the construction of 9 power plants, and 44 plants with 22,600 MW of generating capacity are currently under consideration by the California Energy Commission.[111] All of them will almost certainly be approved, but they will take several years to build.[112] Tens of thousands of additional megawatts of capacity are under construction in other states that are part of the western regional electricity grid. A new study by Resource Data International, a division of Financial Times Energy, concludes, "Even in the West, where shortages and unprecedented high prices have been the rule in 2000, more than enough new capacity is under development to bring power markets into balance and perhaps provide a mild over-correction within the next couple of years."[113]

One could argue that investors' *fear* of environmental opposition and the costs of fighting that opposition to a successful completion explain the lack of plant construction in the 1990s, but little evidence exists to support that claim.

More obvious explanations for the lack of investment in new capacity are low prices and regulatory uncertainty. As discussed earlier, wholesale power prices in California were so low that there was little profit to be gained by increasing production. William Keese, chairman of the California Energy Commission, explains that the demand for generation that built up through the 1990s was for "needle peak demand," defined as the additional supply that would be needed to meet a 4,000 MW surge on the third consecutive day of record-high temperatures. Such peaks are rare (31 in the last 40 years), making new peaking capacity difficult to pay for. "To say people should have built power plants is not rational because they would have lost money."[114]

Moreover, regulatory uncertainty kept investors out through much of the mid-1990s. No power plant applications were filed with the California Energy Commission from 1994 to 1998 because of the investor uncertainty created by deregulation.[115]

Low prices and regulatory uncertainty also explain why states in which environmental activism is low experienced no more investment in new power plants than California. Arizona's population grew 40 percent in the 1990s. The state has a pro-business climate, and yet its power production rose only 4 percent during the 1990s, mostly at existing plants. No one applied to build a major plant in Arizona between the late 1980s and late 1999.[116]

If California had built more power generators during the 1990s, they would almost certainly have been gas–fired facilities because those were the cheapest and easiest plants to site. And because the electricity price increase is largely a reflection of the regional increase in the price of natural gas, those hypothetical plants would have reduced California prices only if enough plants had been built so that the new plants (with their lower heat rates) became the *marginal* source of electricity (rather than older natural gas plants with higher heat rates) and enough plants had been built to eliminate any scarcity rents that are currently in California prices.

In short, given the increase in natural gas prices observed in California, a massive investment in natural gas plants would still have resulted in 15 cent per kWh electricity. And if retail consumers were still paying 6.7 cents per kWh, bankruptcies and blackouts would still occur.

Environmentalist and NIMBY (Not in My Back Yard) agitation, however, has slowed down the regulatory approval process, which requires much more time in California than in other states (several years versus several months). A running joke reportedly popular at the California Energy Commission is that "no plant gets approved unless the paperwork weighs as much as the plant itself."[117] The inability to respond quickly to the supply shock with new power generation can fairly be blamed on rules written to please California's activist community, but again, the Greens are but one part of that community.

Did Killing the Nukes Kill California?

California's well-known campaign against nuclear power has also been blamed for the crisis. In 1989 the nuclear reactor at Rancho Seco was prematurely decommissioned because of environmentalist agitation, sacrificing 913 MW of power daily. In 1992 the San Onofre Unit-1 reactor (one of three reactors on the site), generating 436 MW of power daily, met the same fate.

Blaming the crisis on California's anti-nuclear activists, however, makes little sense. First, even states without well-organized anti-nuclear organizations and growing electricity demand failed to attract investment in nuclear power, suggesting that other factors were at work in discouraging investment in nuclear power plants. Second, natural gas–fired plants throughout the 1990s were simply better investments than nuclear power plants; they were quicker and cheaper to build and, with fuel costs so low, not that much more expensive to operate.[118] Even without state prohibitions and environmentalist opposition, it's extremely unlikely that investors would have chosen to build nuclear plants instead of gas–fired generators.

Similarly, if the Rancho Seco and the San Onofre Unit-1 reactors had been kept open, prices would be lower today only if the extra nuclear capacity reduced the number of hours in the day for which natural gas units set the market price. But neither hydro nor nuclear is the costliest source of power during the daytime, and thus they have no effect on daytime prices. Additional nuclear capacity could have lowered off-peak prices if it had been used instead of natural gas units during off-peak hours.

We repeat: wholesale prices are driven by the costliest source of power at the margin, so the price shock would have been more benign had those nuclear plants been online only if they had displaced the use of natural gas during off-peak hours. An additional daily supply of 1,400 MW might well have headed off some of the blackouts, but because transmission constraints into northern California play such a large role in those blackouts, only the 913 MW from Rancho Seco, located near Sacramento, would have helped.[119]

How Green Is the Grid?

Concern only about *California's* generating capacity, however, ignores the fact that the electric power market in the West is one large, interconnected system. There is no reason to demand that California internally generate all its power any more than to demand that Rhode Island produce all the food it consumes. Generation not built in San Francisco for Bay Area ratepayers, for example, simply gets built elsewhere in Utah, Arizona, or Nevada and is sent to the Bay Area over wire.

But the transportation of electricity requires transmission capacity. Even though transmission capacity costs only one-tenth as much as generation, landowners and other local residents resist new transmission capacity.[120] From 1989 through 1997, transmission capacity per MW of summer peak demand declined by 16 percent. Between 1997 and 2007, transmission capacity relative to summer peak demand is expected to decline another 13 percent.[121]

The inability to respond quickly to the supply shock with new power generation can fairly be blamed on rules written to please California's activist community.

The lack of new transmission capacity—like the lack of new generation capacity—has as much to do with economics as with politics.

But the problem of transmission constraints exists all over the country, not just in California. While environmentalists have been known to agitate against new power lines, they're scarcely the only—or even the largest—group of NIMBY-ites to do so.

Moreover, the lack of new transmission capacity—like the lack of new generation capacity—has as much to do with economics as with politics. Incumbent utilities have little incentive to build new capacity that would make it easier for ratepayers to buy cheaper power from competitors in neighboring states.[122] And utilities do not have an incentive to invest in new capacity when the profits allowed them by regulators are too low to make those investments particularly worthwhile relative to unregulated investments.[123] And with transmission rules still up in the air and unsettled at both the federal and state level, regulatory uncertainty is also damping investment.[124]

News stories also claim that natural gas pipeline capacity constraints are the product of environmentalist or NIMBY-ite opposition.[125] But there is little evidence to suggest that investors have been inhibited from increasing pipeline capacity when profit opportunities presented themselves. Extensive new pipeline capacity into northern California from Canada, for example, was built in the 1990s.[126] The Energy Information Administration observes that pipeline capacity "has grown with end-use demand, and as new supplies have developed, new pipelines have been built to bring this gas to markets."[127] The Gas Research Institute likewise finds that "growth in pipeline capacity is not a constraint on growth in gas supply. . . . If supply is available, history has demonstrated that the pipelines will be built as needed. It is simply an investment and engineering issue."[128]

Little pipeline capacity into southern California was added during the past decade because investors found few opportunities for profit in the construction of new pipelines. The existing pipelines were not fully utilized until this year.[129] High natural gas prices, however, have revived interest in pipeline capacity expansions, and three significant projects were recently announced to take advantage of the newly discovered profit opportunities in transmission.[130] Clearly, the barriers to pipeline expansion in California are not too terribly high when profit opportunities exist.

Accordingly, it's hard to single out the environmentalists as the "cause" of transmission constraints. While they've certainly played a role in opposing grid expansion, even states without well-organized environmentalist lobbies have found it difficult to remedy transmission congestion.

Did Other States Adopt "Better" Designs Than California?

Many analysts have argued that other states deregulated more intelligently than California and thus did not experience the same high prices and shortages.[131] After all, the average price for wholesale power in California was $313 per MWh in the middle of January 2001 compared to $74 per MWh in New England, $63 per MWh in New York, and $39 per MWh in Pennsylvania, New Jersey, and Maryland.[132]

Fuel Inputs Explain All

Although other states have restructured their electricity regulations differently than California has and have not experienced large wholesale price increases, the characteristics of the state plans are not responsible for the lower prices. Pennsylvania, for example, did not force utilities to sell off nearly as many generating assets as did California and allowed long-term contracting for power and established a more robust retail and wholesale market of competing suppliers.[133] But the price differential between power in California and power in the other states that restructured their electricity regulations is the result of fuel composition, not of a "better" regulatory climate.

States east of the Rocky Mountains do not rely on natural gas for their electricity during the winter (and only a few rely heavily on natural gas during peak-demand periods in the summer). For example, during the first nine months of 2000, 19 percent of electricity was generated by natural gas units in New England, 18 percent in New York, 49 percent in California, and only 4 percent in Pennsylvania, New Jersey, and Maryland.[134] Eastern states' reliance on nuclear, coal, and hydropower (which in the East has not suffered from drought) in the winter explains why the electricity crisis has been confined thus far almost exclusively to California and neighboring states, which have had to substitute natural gas for hydro in the production of electricity in the winter.

If major exogenous supply and demand shocks were to hit the states touted as deregulatory "successes," they, too, would find themselves experiencing an increase in wholesale electricity prices. Blackouts would probably not occur, however, because, as best as we can tell, all states except California have fuel pass-through provisions that allow rising fuel costs to be incorporated sooner or later into electricity rates.[135]

Is Coal "Better" Than Gas?

In light of the above, some people might be tempted to argue that California "went wrong" by not embracing coal generation. A typical coal plant is more expensive (almost four times) to build per kW of capacity and less efficient to operate (more Btu from coal are required to generate a kWh of electricity than Btu from natural gas in a new combined-cycle plant), but the cost of coal per million Btu of heat output is less than that of natural gas.[136] Thus comparisons of the two technologies require a comparison of capital and expected fuel costs at expected utilization rates. In 1996 two EIA analysts determined that under all reasonable scenarios natural gas plants are more cost-effective than coal.[137] The EIA again echoed that finding last year in *Annual Energy Outlook 2001:* "Natural gas technologies tend to dominate projected capacity additions because the total cost of electricity generation from these technologies is less than the other options."[138]

Thus, California regulators cannot be faulted for not encouraging additional coal-fired generation. Investors, not state regulators, determine what sort of power plants are built, and investors acted rationally by eschewing coal-fired facilities in favor of natural gas–fired facilities.

Reservations about Reserve Capacity

Can California's regulatory regime be blamed for providing less reserve capacity than is maintained in other states? Does someone need to "think about" reserve capacity, or can the choice be left to market forces?[139]

New England, New York, and the mid-Atlantic states have installed-capacity requirements in their deregulated markets. Utilities are required to have available generation capacity to meet their peak demand or face penalties. New York, for example, sets the penalty at three times the estimated average cost of building a peak-demand unit, which presumably induces utilities to build or contract for sufficient peak-demand units.[140] California and Ontario do not have installed-capacity regimes. When supplies are tight in those regions, prices will rise sufficiently to induce the installation of new supply.

Retail power prices in the installed-capacity regimes are higher, on average, to pay for the excess capacity, but peak prices are probably lower.[141] But damped peak prices, in effect, socialize the costs of meeting peak demand and induce less consumption reduction by consumers during peak periods, both of which are economically inefficient. The installed-capacity regimes are a holdover from the cost-of-service regulated era with its bias toward new supply rather than demand reduction through the use of price signals.

In an unregulated market, excess capacity would lead to prices equal to marginal cost. Because electricity generation is very capital intensive (thus fixed costs are high relative to marginal costs), firms would not recover their fixed costs under marginal cost pricing.[142] Thus excess capacity would be built only if subsidies were offered or regulations enacted rather than as the result of simple

Eastern states' reliance on nuclear, coal, and hydropower in the winter explains why the electricity crisis has been confined almost exclusively to California and neighboring states.

The main difference between California and other western states is that the latter have increased prices to consumers whereas until recently California has not.

market forces. Therefore, unregulated electricity prices will be more volatile than prices in other markets in which marginal costs are not much lower than average costs. Though California may appear to provide evidence of the failure of the market system and support for the installed-capacity regime, that is true only because of retail price controls, which eliminate demand reduction when supplies are tight and exacerbate the price increases observed in the wholesale market.

The Difference between California and the Rest of the West

Even though electricity regulation and policy discussion occur at the state level, the United States really has three electricity systems: the eastern interconnection, the western interconnection, and the Texas system, which has limited direct- rather than alternating-current connections with the eastern interconnection.

The focus on California creates the impression that the other states in the western interconnection are exempt from California's difficulties. That is only partially correct. Because electricity supplies are bought and sold all over the western interconnection, in the absence of transmission constraints, transportation-cost-adjusted prices everywhere in the West will be the same.[143] Thus it is not possible for any western state to insulate itself from a shock to supply or demand that occurs anywhere in the western interconnection.[144]

Even though the transmission grid does not allow states to insulate themselves from each other's electricity situations, the perception exists that other western states built more supply than did California in the 1990s relative to demand increases and thus are shouldering more than their share of responsibility for electricity supply.[145] That is incorrect.

Demand has been exploding outside California, and supplies have not increased commensurately. Eighty-five percent of the growth in electricity demand in the West since 1995 has occurred outside California.[146] But no state except Montana has increased electric power production more than population growth. In the 1990s Arizona's population grew by 40 percent and electricity demand grew at nearly double that rate, but power production rose only 4 percent despite Arizona's having almost none of the environmental restrictions blamed for keeping California from expanding capacity.[147] In Nevada during the same period, population grew by 66 percent but power production by only 44 percent.[148] John Harrison, a member of the Northwest Power Planning Council, which represents Idaho, Montana, Oregon, and Utah, said: "Our supply is extremely tight too. We haven't been building any new power plants either."[149]

The main difference between California and other western states and the explanation for the lack of "crisis" mentality in the other states is that the latter have increased prices to consumers whereas until recently California has not. Nevada will have raised residential rates by 75 percent from 2000 to 2003.[150] Rates in Tacoma, Washington, have risen 50 percent, and utilities in Idaho, Arizona, and Utah have also announced large increases.[151] These price increases are average rather than real-time, but at least prices are rising. Thus utilities do not go bankrupt, and suppliers do not withhold because of fears of nonpayment.

The Rescue Plans

A number of initiatives have been undertaken to alleviate the power crisis in California, and other plans remain on the drawing board. Unfortunately, few if any accurately diagnose the problem or treat anything beyond the superficial economic symptoms of the underlying disease.

Price Controls

Gov. Gray Davis and most of the California political establishment believe that political management of supply shocks is better for consumers than economic management via free prices. Their argument is simple: When supply and demand are fairly rigid in the short run—in this case, because of both natural market characteristics and burdensome regulatory policies—high prices will over the short run mostly transfer wealth from consumers to firms rather than induce new supply or decrease demand. This is particularly true for baseload coal and nuclear plants, the marginal costs of operation of which are much less than those of the old inefficient natural gas units used to meet aggregate demand in California.[152] So governments institute price controls and issue legal orders to require supply increases and demand reductions rather than allow prices to achieve the same result.

What if regulators attempted to reduce wholesale prices by restricting the profit opportunities of inframarginal suppliers with, say, a windfall profits tax or some sort of "cost-plus" rate cap? Negative supply and demand effects would likely result.

On the supply side, such policies would reduce the incentive to invest in cheap energy production. After all, why care whether your plant is more efficient or cost competitive than the competition if the state ensures that your profit margins are no greater than those of your less-efficient competitors? Such policies would also bias investment away from facilities with high up-front costs and low marginal costs (coal, nuclear, and most renewables) and toward facilities with lower up-front costs and higher marginal costs (natural gas and fuel oil). Both fuel diversity and economic efficiency would suffer.

On the demand side, mandating prices below market-clearing levels would send the wrong price signals about the cost of consuming additional units of electricity, artificially increasing demand at the very time that demand reductions are necessary to prevent collapse of the grid into blackout status. Such a demand increase would have the perverse effect of actually *increasing* the price of power from marginal suppliers (more consumers chasing a fixed amount of service).

Can politicians intervene in the electricity market to reduce the wealth transfer and yet preserve the important incentive functions of prices? In theory, governments can enact price controls on inframarginal (existing) output but leave incremental supply free from controls. This preserves static efficiency by pricing incremental demand and supply correctly and reduces the wealth transfer from consumers to producers. But, to the extent investment occurs because of the possibility of making profits during periods of tight supply, dynamic efficiency is negatively affected by even this policy. In addition, once the government controls prices on existing output, political struggles ensue over access to that output. As economist Ben Zycher warns, "Feel free to bet the rent money on the prospect of politicized electricity rates, designed to subsidize various consumer groups and geographic regions with important allies in the Legislature at the expense of other groups."[153]

Once the government controls prices on existing output, political struggles ensue over access to that output.

Consider two past policy schemes that are analogous to the schemes that Governor Davis proposes for California: the federal intervention in oil markets after the 1973 oil shock and rent control in New York City. The Emergency Petroleum Allocation Act of 1973 allowed "new" supplies of crude oil and increases from "old" supplies to command market prices but controlled prices for existing supplies. Because of historical patterns, some refineries had 0 access and others 100 percent access to old oil, which caused enormous variation in profits because gasoline sold at market-clearing prices, which were high regardless of the amount of "old" oil used in the refining process. That, in turn, led to a political fight over access to the wealth created by price-controlled "old" oil. The only winners were the lawyers who wrote the regulations and tried the cases about what was and was not "old" oil and refineries that had access to cheap "old" oil.[154]

Similarly, in New York City after World War II rent controls were left on the existing housing stock, but new units were unaffected. The city has since reneged on its pledge to not impose controls on units built after 1947, and the controls have led to a black market in which access to rent-controlled

Legal orders can reduce demand, but at best they are much more costly to develop and enforce than price increases, which lead all people, not just government lawyers, to think about how to conserve.

units is "sold" with the proceeds going to existing tenants and brokers rather than to the legal owners.[155]

In both the oil and housing policy experiments, the wealth transfers suppressed by price controls were not recycled to the public at large. They were instead captured by oil refineries and lucky tenants who happened to live in price-controlled housing. And because of investors' concerns about future confiscation of profits, investment has been less than optimal, particularly in NYC housing.

Legal Orders

Legal orders can reduce demand, but at best they are much more costly to develop and enforce than price increases, which lead all people, not just government lawyers, to think about how to conserve. Even if they work, many orders have only symbolic effects. And at worst they have perverse economic consequences.

News articles often describe the many changes in behavior that mangers propose after a legal order is issued. For example, in response to an order by the governor to all state departments to reduce energy use by 5 percent, the California Department of Water Resources announced that it would use aqueduct pumps at night rather than during the daytime peak.[156] The implication is that orders are effective. But under real-time market prices, use of aqueducts off peak, as well as many other changes no one has ever thought about, will occur without orders telling people what to do.

The category of symbolic but ineffective legal orders is well represented by Governor Davis's proposed regulation to require car dealerships to turn off most of their lights at night.[157] But electricity is relatively cheap and plentiful at night. It's electricity during the daytime—particularly on warm summer afternoons and early evenings—that is expensive and scarce. Nighttime conservation does nothing to prevent blackouts.

The perversity of regulation is superbly illustrated by a proposal to ban power producers from exporting electricity to other states.[158] Such a regulation would lead to other states' restricting electricity exports to California. And because California typically imports much more power annually than it exports, such a trade war would have devastating consequences for California ratepayers.[159]

Subsidizing Conservation

Desperate to reduce electricity demand by some mechanism other than the elimination of retail price caps, California has adopted an $850 million energy conservation initiative, which consists primarily of programs to subsidize ratepayer purchases of energy efficient appliances and technologies.[160]

The fundamental problem with such subsidies in a price-controlled market is that energy efficient appliances reduce the costs of operation. That may not be a major issue when it comes to, say, the television set (we won't watch more TV just because it costs a little less to turn on the set), but for appliances like air conditioners that make all the difference during peak-demand periods, energy efficiency simply reduces the marginal cost of energy services and thus increases—not decreases—energy consumption. This is known as the "rebound effect," and it's been well established by economic researchers.[161] The upshot is that the gains of energy efficient appliances are at least partially offset by increases in appliance operation time.

It's not as if we haven't tried such programs before. Utilities across the nation have spent about $20 billion since the mid-1980s to subsidize ratepayer investments in energy efficiency.[162] Yet examination of the data reveals that utilities that invested heavily in subsidies experienced no reduction in electricity demand relative to utilities that did not invest in subsidies.[163]

There are several reasons in addition to the rebound effect for this. First, most consumers who take advantage of these programs are "free riders"; they would have bought those devices with or without the handouts.[164] Second, the high initial cost of many of those technologies (like the fabled $40 light bulb) implies that it can take years to recoup the costs of those investments, even after the subsidy. Other investments are far more attractive by comparison.[165] Third, many of the "wonder-techs" are known to be poor performers, trading off other consumer conveniences to eke out a little more efficiency at the margin. People are understandably leery of pitching thousands of dollars worth of appliances with years of life left in them to embrace unknown technologies that often have their own problems and save money only after years of operation, if ever.

The hard truth is that people will conserve energy only when they think that the inconveniences of doing so are outweighed by the money saved by such investments or by such behavioral changes. Reducing the marginal cost of energy consumption is exactly the wrong approach. And even were it the right approach, government programs that put their faith in subsidized energy conservation rather than free energy prices helped give us the California mess in the first place. Only by letting prices do their job can energy conservation be achieved. Everything else is political smoke and mirrors.

Public Ownership

Some people in California argue for public ownership in addition to price controls and legal orders. They point out that the Los Angeles Department of Water and Power continues to sell power to ratepayers at prices far below wholesale prices in the California spot market without incurring the debts incurred by the investor-owned utilities.

The correct framework in which to analyze LADWP is the one we used in our discussion of installed-capacity regimes. Currently, LADWP has excess hydro- and coal-fired generators under contract. It sells the excess on the spot market, earning large profits just like private owners of similar facilities, and uses the profits to subsidize the consumption of its current customers instead of returning them to taxpayers as private utilities would return profits to shareholders.[166]

The LADWP policy has the appearance of a free lunch, but it is not. Until the spring of 2000, when those excess supplies became valuable on the spot market, in order to pay for the unused excess capacity, LADWP customers had to pay more for electricity than they would have paid in a spot market.

In addition, if LADWP supplements those power supplies with gas–fired electricity, its incremental costs are similar to those of private generators. But unlike the deregulated wholesale market, LADWP prices its output on a weighted-average basis passing on the low costs of coal and hydro to consumers rather than charging for all output on the basis of the price of the most expensive input, natural gas. As we demonstrated earlier, such pricing is unsustainable because it encourages extra demand, the costs of which are more than incremental revenues. Eventually, LADWP will have to obtain more capacity than it would under marginal-cost pricing because consumers are not charged enough to reflect their incremental demands on the system and thus LADWP's ultimate costs are higher than they otherwise would be because of its pricing policies.

Long-Term Contracts

In early February, the California legislature adopted A.B. 1X, authorizing the state to directly contract with generators and marketers for electricity. Governor Davis, the author of the plan, hoped that 95 percent of the state's electricity demand could be secured through such contracts, leaving only 5 percent of the state's needs to the spot market. The governor further hoped that 3- to 10-year contracts would allow California to lock in prices at a weighted average of 5.5 cents per kWh ($55 per MWh). Davis's expectations were dashed, however, when 38 power suppliers submitted bids at a weighted average of 6.9 cents per kWh.[167] Although the governor announced that the state had agreed to pay $42 billion for this power over 10 years, little else is known of the arrangements.[168]

But will the contracts really lower prices from current spot levels? First, the 6.9 cent figure is for nonpeak rather than peak supply. While information is sketchy, reports suggest

Only by letting prices do their job can energy conservation be achieved. Everything else is political smoke and mirrors.

Long-term contracts do not offer a "better deal" than spot market purchases.

that bids for long-term peak supply average around 25 cents per kWh.[169] Second, the 6.9 cent figure is a weighted average. As discussed earlier, the proper price for electricity is not the average price but the price paid for the most expensive source used during any one-hour period. Even if the state were to resell that power to ratepayers at cost, it would presumably be sold on the basis of the average acquisition cost and thus would be priced too cheap relative to an unregulated market.

If long-term contracts could hold down market-clearing prices in free markets, what are we to make of the natural gas market? According to the American Gas Association, only 9 percent of all wholesale natural gas purchases are made from the spot market,[170] but the price spike occurred. If long-term contracts could dampen wholesale prices during spikes, we wouldn't have seen anything like the natural gas price explosion of 2000–01.

There's also good reason to think that long-term contracts signed by the state will be more expensive than long-term contracts signed by private parties. Because future politicians will be tempted to renege on those contracts if spot prices fall below the contract price, producers will include a premium in their bids to cover that risk. Confidence in the state's good faith is not enhanced by the current talk of confiscating plants and criminalizing pricing activity when prices are arbitrarily thought to be "too high."[171]

Regardless of the details of California's arrangements, the argument that long-term contracts will reduce costs in the long run is itself extremely dubious. First, there is the question of timing. As Nobel Prize–winning economist Daniel McFadden recently pointed out, "Negotiating long-term contracts right now, when California is in a weak market position and out-of-state generators are in the driver's seat, is likely to put the state at a future competitive disadvantage."[172]

Remember, below-market prices in the short term can come only at the expense of above-market prices for years to come, and locking in long-term prices at the peak of a price spike is hardly the best way to minimize cost in the long run. Peter Navarro, a professor of economics at the University of California-Irvine, estimates that, by 2003 or so, wholesale electricity prices in California will average about 5 cents a kilowatt-hour, given the additional generating capacity under construction or in the planning stages. "By using huge sums of taxpayer money to lock in long-term power contracts, California is making a mistake that will haunt its economy for years."[173]

Second, long-term contracts do not offer a "better deal" than spot market purchases.[174] Borenstein writes, *"On average, a purchaser buying power in forward markets (or through long-term bilateral contracts) will not receive lower power costs than a purchaser buying in the spot market."*[175] Long-term contracts simply reallocate the risk of price volatility from the consumer to the generator or marketer that provides the fixed-price guarantee. But the guarantee is not free. Sellers of such guarantees require a premium to accept this reallocation of risk. Generators (or marketers) do not offer fixed prices that result in lower returns than sales on the spot market. In fact, spot market prices for electric and gas utilities have historically been more favorable to consumers than contract prices.[176]

Everyone has forgotten that we've been down this road before. In the late 1970s, soaring electricity prices led Congress to pass the Public Utility Regulatory Policies Act. That law forced utilities to sign long-term contracts with independent power producers at the costs a utility would avoid because it did not have to build new supply itself. Regulators in California and New York set "avoided cost" administratively at rather high levels on the basis of the expectation of high prices for conventional fossil fuels, and utilities signed long-term contracts based on those expectations.[177] It seemed like a good deal at the time. But when electricity prices collapsed in the mid-1980s, the power companies had to keep buying this power while spot prices were around 2–3 cents per kWh. Largely because of the PURPA contracts, Californians by the mid-1990s were paying

35 percent more for their electricity than ratepayers in other states.

An important goal of California's misnamed "deregulation" of 1996 was to eliminate the cost disadvantage for California consumers created by the long-term PURPA contracts. If power generators had to compete with one another and sell in a spot market, the reasoning went, ratepayers would never again be saddled with such contractual boondoggles. Of course, California went overboard. The state has no business telling companies what kind of contracts they can and cannot sign and under what terms and conditions they can and cannot enter a market. But that's not to say that a wholesale replay of the disastrous 1970s regime is in order.

What if California's utilities had signed long-term contracts before the wholesale electricity price increases occurred? Wholesale prices would still be sky-high. That's because the causes of the increase—skyrocketing wholesale natural gas prices, a decline in regional hydroelectric power because of a three-year drought, and sharp weather-related increases in demand—have little to do with state policy. Had utilities entered into long-term contracts before the spike hit, independent power producers would be obligated to sell power at, say, 6 cents per kWh despite the fact that it costs them 15–50 cents per kWh to make that power. It wouldn't be long before the independent power plants started to declare bankruptcy and tear up the contracts, which is what happened during the mid-1980s in the natural gas industry. It's already happening to the few generators (including Enron) that signed long-term contracts in California.[178]

The Best Way Out

The electricity crisis in California will most likely run its course by 2003 or 2004 regardless of what the state or federal government does or does not do in the meantime.[179] As noted previously, huge investments in new electricity generation will be largely online by then, eliminating the supply shortage and bringing prices down to—or even perhaps below—historic levels.[180] Moreover, investments in natural gas supply driven by today's high wholesale prices will almost certainly burst the gas price bubble even if the federal government refuses to open promising gas fields on public lands currently off-limits to the industry.[181]

As the old saying goes, however, "in the long run, we'll all be dead." It's the short run that counts now in California. How can the state get through the next two years so that a market-driven return to normality occurs with the least amount of economic pain?

At the time of this writing, California is alleging that it will have enough power at its disposal to meet summertime demand. But unless the state is the beneficiary of extremely mild weather, those assertions are threadbare and wishful thinking.[182]

Kill the Retail Price Caps

Even Governor Davis understands that the repeal of retail price controls is the surest and quickest solution to the problem: "If I wanted to raise prices, I could solve this problem in 20 minutes."[183] Initially, he did not choose to do so because of the perception that demand is fixed in the short run and not significantly affected by price. Thus, freeing electricity prices would simply allow suppliers to charge whatever they wish, transferring wealth from consumers to producers.[184]

Even Governor Davis understands that the repeal of retail price controls is the surest and quickest solution to the problem.

Very little evidence exists on the effects of changes in electricity prices on demand because, under regulation, prices have not been allowed to vary much. But consumers in San Diego were part of a natural experiment from July 1999 through the end of August 2000. Under the terms of A.B. 1890, San Diego Gas and Electric had accumulated enough extra revenue from the start of "deregulation" in April 1998 to recover its stranded costs by the end of June 1999, so its rates were freed from controls and became a five-week moving average of wholesale prices.[185] By the time rate controls were reenacted after August 2000, retail rates had doubled. Bushnell and Mansur estimate that,

Monthly charges based on average costs do not keep up with the daily fluctuations in wholesale prices. Nor do they send the correct signals regarding marginal costs, a flaw long understood even by environmentalists.

after controlling for weather and other sources of non-price-related demand variation, a doubling of prices resulted in a demand reduction of 2.3 percent.[186]

This is an extremely low price elasticity, giving some support to the sentiments expressed by Governor Davis. But because California politicians were already discussing rate rollbacks during the summer of 2000, consumers may not have altered demand as much as they would have if they had believed that market prices were permanent. Ratepayers probably altered their investment and consumption very little because they believed (correctly) that the rate hikes would be temporary. Had they been convinced that prices would stay high for some time, even greater demand reductions would have been observed. Thus, the price responsiveness estimated by Bushnell and Mansur should be considered an extreme lower bound of the true value.

There is circumstantial evidence to back this point. Energy consultant Bill LeBlanc reported in a recent study that large commercial, industrial, and institutional consumers consider 17 percent of their aggregate demand load "nonessential" and that, were retail electricity prices at 50 cents per kilowatt-hour (a threshold crossed by the wholesale market on dozens of occasions over the past year), 27 percent of the demand from those firms would be eliminated, resulting in "a huge, cost-effective dent in California's electricity shortfall."[187]

Price controls in petroleum markets in the 1970s were also justified on the basis of the lack of short-run price responsiveness on the part of consumers. But petroleum markets have been free of controls since the early 1980s, and in 1990–91 and 2000 price shocks occurred. How did consumers respond?

In 2000 gasoline prices increased by about 50 percent. Despite the booming economy, all those SUVs, and an aggregate increase in vehicle registrations of 1.8 percent, aggregate gasoline consumption declined by about 1 percent from 1999, the first nonrecession reduction in recent history.[188] Ronald J. Planting, manager of information and analysis at the American Petroleum Institute, said, "The increase in prices was enough to spur at least some consumers to lessen lower priority travel and take other fuel-saving measures."[189] The belief that high prices do not affect demand in relatively inelastic markets and that voters will not accept price increases does not hold in gasoline markets. Given the inelasticity of both the supply and the demand side of the electricity market, even moderate reductions in demand, as a result of freeing prices, would have a major effect on wholesale prices.

Institute Real-Time Pricing

Although eliminating retail rate caps is a crucial component of any reform, it will fall short of fixing the fundamental problem in the electricity market. Monthly charges based on average costs do not keep up with the daily fluctuations in wholesale prices. Nor do they send the correct signals regarding marginal costs, a flaw long understood even by environmentalists who argued that average-cost pricing produced artificially low prices and, thus, excessive energy consumption.

Unfortunately, few consumers in California or elsewhere have meters that can register hourly consumption. The installation of load-sensitive meters would take time, but the technology is well established. In fact, load-sensitive meters have operated well in France for years.[190] Borenstein proposes that large commercial users be required to use real-time meters by this summer. The largest 18,000 customers account for about 30 percent of peak load in California, and the 10 million remaining customers account for the remaining 70 percent.[191] Borenstein believes that real-time pricing for the largest customers would have large benefits for the system as a whole because generators would then worry about the possible demand-reduction consequences of their pricing behavior. And the cost, time, and political difficulties of installing real-time meters for the remaining 10 million customers would be avoided.

According to EPRI (formally known as the Electric Power Research Institute), users of 8,000 MW of load in California already have real-time meters in place.[192] If real-time pricing were available on a voluntary basis, EPRI estimates that peak demand would be reduced by 2.5 percent and prices by 24 percent.[193]

Abolish the ISO

The underlying belief animating the case for control of the day-to-day operation of the power grid by a nonprofit stakeholder-governed institution (the ISO) is the idea that efficient operation of the grid is more an engineering challenge than an economic challenge. That belief is dubious in theory, and it has been destructive in practice.

Economist Robert Michaels persuasively argues that efficient investment decisions are most likely to result from a form of governance in which wealth maximization is the sole interest of the governors. And because the ISO is an organization of stakeholders (industrial and residential consumers, government buyers, marketers, independent power producers, environmentalists, and union representatives), battles about distribution, rather than wealth maximization and economic efficiency, are likely to dominate its decisionmaking because the members manage an asset that they do not own.[194]

The operation of the grid should therefore be given back to the utility owners. To address the concern that utilities will manipulate traffic along the grid to disadvantage competitors, generators and large consumers should be allowed to purchase equity interests in the grid. This would help to resolve disputes and provide the necessary incentives for efficient operation and improvement of the system. A similar arrangement for interstate oil and gas pipelines works well with little litigation or government intervention.[195]

Conclusion

H. L. Mencken once said that "democracy is the system that lets the people say what they want and then gives it to them, good and hard." That appears to be the case in California today. A recent Field poll asked Californians whether they would prefer a regime that capped the retail prices of electricity but produced the occasional blackout or a regime that had higher retail prices but no blackouts. Nearly two-thirds of the respondents favored the former.[196] Governor Davis is imposing an East German policy on the electricity market because most Californians prefer it.

A return to the old pre-1996 monopoly, cost-of-service, obligation-to-serve regime promises little. California regulators have demonstrated that they're not very good at overseeing that sort of enterprise. Remember, electricity rates in those "good old days" were 35 percent above the national average by the early 1990s.[197]

A complete state takeover of the system promises even less. The problem with state ownership of industries in, say, East Germany was not that those industries were run by ignorant East Germans rather than smart Californians. If the 20th century has taught us anything, it's that government is a horrible business manager and an incompetent economic planner no matter what industry we're talking about or what the nationality of the planner may be.

The simple fact is that high prices for power must be paid. Because it's politically difficult to have ratepayers pick up the tab on their monthly bill, California's politicians have decided to have taxpayers pick up the tab out of the state budget surplus. So Californians will not escape high prices. The problem with paying bills that way, however, is that the high prices will not affect electricity demand and thus will not play their intended role in allocating scarce goods as they would if they were simply passed on through the market.

Our arguments are not particularly controversial within academia. Electricity economists identified with both the left and the right have made similar arguments in "Manifesto on the California Electricity Crisis," produced under

Governor Davis is imposing an East German policy on the electricity market because most Californians prefer it.

The California electricity crisis is a story about what happens when price controls are imposed on scarce goods.

the auspices of the Institute of Management, Innovation, and Organization at the University of California-Berkeley.[198] That's largely because the California electricity crisis is not really a story about environmentalists gone bad, deregulatory details ignored, or unrestrained capitalists running amuck. It's a story about what happens when price controls are imposed on scarce goods.

Notes

The authors would like to thank Douglas Hale, Tim Brennan, Richard Gordon, Rob Bradley, and Charlotte Le Gates for their comments on earlier drafts of this paper.

1. In 1996 average revenue per kilowatt-hour was 6.9 cents for the United States and 9.3 cents for California. In 1996 average revenue per kilowatt-hour for residential customers was 8.4 cents for the United States and 11.3 cents for California. See Energy Information Administration, *Electric Power Annual 1996,* vol. 1, Tables 21, 27, pp. 37, 42, http://tonto.eia.doe.gov/FTPROOT/electricity/0348961.pdf.

2. For a discussion of why the rate-of-return regulatory system, which seemed to work satisfactorily for so many decades, finally broke down, see Peter VanDoren, "The Deregulation of the Electricity Industry: A Primer," Cato Institute Policy Analysis no. 320, October 6, 1998, pp. 3–8. For a discussion of the political dynamics that forced legislative restructuring in the mid-1990s, see Benjamin Zycher, "Market Deregulation of the Electric Utility Sector," *Regulation* 15, no. 1 (Winter 1992): 13–17.

3. A.B. 1890 can be read in its entirety at the Reason Foundation's "California Electricity Crisis Center," http://www.rppi.org/electricity/background. html.

4. Robert Michaels, "Stranded in Sacramento: California Tries Legislating Electricity Competi-tion," *Regulation* 20, no. 2 (Spring 1997): 52–56.

5. Peter Passell, "A Makeover for Electric Utilities," *New York Times,* February 3, 1995, p. C1. A Department of Energy study in 1997 placed the figure at between $72 billion and $169 billion. U.S. Department of Energy, Energy Information Administration, *Electricity Prices in a Competitive Environment,* p. ix.

6. See Alfred Kahn, "Let's Play Fair with Utility Rates," *Wall Street Journal,* July 25, 1994, p. A15; James Q. Wilson, "Don't Short-Circuit Utilities' Claims," *Wall Street Journal,* August 23, 1995, p. A12; William J. Baumol and J. Gregory Sidak, *Transmission Pricing and Stranded Costs in the Electric Power Industry* (Washington: American Enterprise Institute Press, 1995); William J. Baumol, Paul L. Joskow, and Alfred E. Kahn, *The Challenge for Federal and State Regulators: Transition from Regulation to Efficient Competition in Electric Power* (Washington: Edison Electric Institute, 1995); and J. Gregory Sidak and Daniel F. Spulber, *Deregulatory Takings and the Regulatory Contract* (New York: Cambridge University Press, 1997). For a summary of the arguments, see Peter Fox-Penner, *Electric Utility Restructuring: A Guide to the Competitive Era* (Vienna, Va.: Public Utility Reports, 1997), pp. 390–97.

7. For arguments against stranded-cost recovery, see Robert Michaels, "Stranded Investments, Stranded Intellectuals," *Regulation* 19, no. 1 (Winter 1996): 47–51; William Niskanen, "The Case against Both Stranded Cost Recovery and Mandatory Access," *Regulation* 19, no. 1 (Winter 1996): 16-17; Richard Gordon, "An Insider's Upside-Down View of Deregulation," *Regulation* 22, no. 2 (Spring 1999): 54–56; and Timothy J. Brennan and James Boyd, "Stranded Costs, Takings, and the Law and Economics of Implicit Contracts," *Journal of Regulatory Economics* 11, no. 1 (January 1997): 41.

8. Peter VanDoren, "Transitional Losses: Criteria for Compensation," *Regulation* 20, no. 1 (Winter 1997): 41–47.

9. Theresa Flaim, "The Big Retail 'Bust': What Will It Take to Get True Competition?" *Electricity Journal* 13, no. 2 (March 2000): 41; and Ahmed Faruqui, "Electric Retailing: When Will I See Profits?" *Public Utilities Fortnightly,* June 1, 2000, p. 33. Faruqui reports that more than 20 percent of California industrial customers had switched by February 2000.

10. For a contemporaneous critique of A.B. 1890, see Jerry Taylor, "A Freer Market Would Lower Energy Costs: Half Measures Fall Short," *San Diego Union Tribune,* February 2, 1997. For an even earlier attack on this restructuring model, see Jerry Taylor, "Electric Utility Reform: Shock Therapy or Managed Competition?" *Regulation* 19, no. 3 (Summer 1996): 64–76.

11. Paul Joskow and Edward Kahn, "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market during Summer 2000," Table 1, p. 8, Unpublished manuscript, http://web.mit.edu/pjoskow/www/JK_ PaperREVISED. pdf.

12. Paul Joskow, "California Can Tame Its Crisis," *New York Times,* January 13, 2001, p. A31.

13. Rebecca Smith and John R. Emshwiller, "California's PG & E Gropes for a Way Out of Electricity

Squeeze," *Wall Street Journal,* January 4, 2001, p. A1.

14. Anthony York, "The Deregulation Debacle," January 30, 2001, http://www.salon.com/ news/ feature/2001/01/30/deregulation_mess/print.html. In hindsight, the bids over book value should have been seen by analysts as a signal that industry insiders were betting with their investment dollars that future reductions in supply would make existing generators very profitable.

15. Robert McCullough, "Price Spike Tsunami: How Market Power Soaked California," *Public Utilities Fortnightly,* January 1, 2001, pp. 22–32

16. Quoted in Steve Schmidt, "Expertise on Energy No Longer Academic," *San Diego Union Tribune,* March 24, 2001, p. A3.

17. North American Electric Reliability Council, "2000 Summer Assessment," May 2000, ftp://www.nerc.com/pub/sys/all_updl/docs/ pubs/summer2000.pdf. Table 2, p. 8, projects a 9,728 megawatt reserve over a projected demand of 49,273 megawatts.

18. Ibid., p. 39.

19. Ibid., pp. 3–4.

20. Joskow and Kahn, Table 1, p. 8.

21. North American Electric Reliability Council, "2000/2001 Winter Assessment," reported in "Power Systems Sufficient to Meet Winter Demand, NERC Says," *Energy Report,* December 4, 2000, p. 2.

22. Edward Krapels, "Was Gas to Blame? Exploring the Cause of California's High Prices," *Public Utilities Fortnightly,* February 15, 2001, p. 29.

23. Energy Information Administration, *Electric Power Annual 1999,* vol. 1, Table A20, p. 46, http://www. eia.doe.gov/cneaf/electricity/epav1/epav1. pdf.

24. Krapels, p. 32.

25. Bruce Radford, "Key to the Citygate," *Public Utilities Fortnightly,* January 1, 2001, p. 4.

26. Krapels, p. 31.

27. Mark Mazur, "Statement to Committee on Energy and Natural Resources U.S. Senate," December 12, 2000, p. 1, http://www.eia.doe.gov/ pub/oil_gas/ natural_gas/presentations/2000/testimony_on_natural_gas_demand/1211sen-test. pdf.

28. EIA estimated that, as of February 16, 2001, the United States had 1,038 billion cubic feet of natural gas in storage, 32.9 percent less than the five-year average. See Energy Information Administration, *Natural Gas Update,* February 22, 2001, http://www. eia.doe.gov/oil_gas/natural_gas/special/natural_ gas_update/natgas_update.html. For a discussion of the "boom and bust cycle" that struck the natural gas market last year, see Judith Gurney, "U.S. Faces Natural Gas Price Shock," *Energy Economist* 229 (November 2000): 15–18.

29. Storage in the West was an astonishing 55.6 percent less than the five-year average. On February 21, 2001, spot prices were $5.20 per million Btu at Henry Hub, Louisiana, $5.51 in Chicago, and $21.69 in Southern California. See Energy Information Administration, *Natural Gas Update,* February 22, 2001.

30. Energy Information Administration, "A Look at Western Natural Gas Infrastructure during the Recent El Paso Pipeline Disruption," no date, available on the EIA Natural Gas Update Web site, http://www. eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2000/elpaso_disruption/elpaso. pdf

31. Alex Barrionuevo, John Fialka, and Rebecca Smith, "How Federal Policies, Industry Shifts Created the Natural Gas Crunch," *Wall Street Journal,* January 3, 2001, p. A1.

32. Energy Information Administration, *Monthly Energy Review,* February 2001, Table 4.1, p. 73.

33. "Rig Count Expected to Jump by 31% in 2001," *Energy Report,* December 25, 2000, p. 8.

34. Mazur, p. 7.

35. "Group Calls on FERC to Cap Wholesale Prices," *Energy Report,* February 12, 2001, p. 11.

36. Personal conversation with A. Michael Schaal at Energy Ventures Analysis, Arlington, Virginia, December 19, 2000.

37. The rate at which the energy contained in natural gas is converted into electricity is called the "heat rate." A standard heat rate for an older plant is around 10,000 Btu per kWh. The most inefficient plants require 16,000 Btu per kWh. Newer combined-cycle cogeneration plants have heat rates of around 7,000 Btu per kWh. The rate of 10,000 Btu per kWh is often used for rough calculation because natural gas prices in dollars per million Btu become electricity prices in cents per kWh. For example $10 per million Btu natural gas results in 10 cents per kWh electricity costs for a 10,000 Btu per kWh electric generating plant. See Krapels, p. 32, for an example of use of the rough calculation for an average and an inefficient plant. See J. Alan Beamon and Steven H. Wade, "Energy Equipment Choices: Fuel Costs

and Other Determinants," *Monthly Energy Review,* April, 1996, Table 3, p. x, for a heat rate estimate on a new natural gas combined-cycle plant.

38. For representative discussions, see Jim Yardley, "Texas Learns How Not to Deregulate," *New York Times,* January 10, 2001, p. A12; and Smith and Emshwiller, "California's PG & E Gropes for a Way Out."

39. Severin Borenstein, "The Trouble with Electricity Markets (and Some Solutions)," Program on Workable Energy Regulation Working Paper (PWP-081), January 2001, http://www.ucei.berkeley.edu/ucei/PDF/pwp081.pdf.

40. Lovins's arguments are analyzed in Franz Wirl, *The Economics of Conservation Programs* (Boston: Kluwer Academic Publishers, 1997), pp. 83–84.

41. Energy Information Administration, *Electric Power Annual 1999,* vol. 1, Table A12, p. 39, http://www.eia.doe.gov/cneaf/electricity/epav1/epav1. pdf.

42. S. A. Van Vactor and F. H. Pickle, "Money, Power and Trade: What You Never Knew about the Western Energy Crisis," *Public Utilities Fortnightly,* May 1, 2001, p. 35.

43. Krapels, p. 30.

44. Van Vactor and Pickle, p. 35.

45. "BPA Mulls Possible 30% Rate Increase," *Energy Report,* January 29, 2001, p. 12.

46. Robert Skai and Colleen Woodell, "Northwest U.S. Drought to Challenge Utilities," Standard & Poor's, April 5, 2001, http://www.standardandpoors.com/Forum/RatingsCommentaries/CorporateFinance/Articles/; and "Dry Winter Dampens Northwest Power Outlook," *Energy Report,* March 19, 2001, pp. 9–10.

47. "Northwest Short 5,000 MW of Hydro," *Energy Report,* May 7, 2001, p. 14.

48. "West Coast Water Woes Mulled," WaterTech Online, April 3, 2001, http://www.watertechonline.com/news.asp?mode=4&N_ID=21276.

49. Krapels, p. 30.

50. "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," p. 5-5, http://www3.ferc.fed.us/ bulkpower/bulkpower.htm.

51. Ibid.

52. Ibid.

53. Consumption by utilities in May through October 1999 was 65.718 billion cubic feet (BCF). During the same period in 2000 consumption was 80.463 BCF. See *Natural Gas Monthly,* March 2001, Table 18, p. 43.

54. Van Vactor and Pickle, p. 36.

55. The average temperature in the lower 48 states in November and December 2000 was 33.8 degrees Fahrenheit, the coldest since the start of modern nationwide record keeping in 1895. See Andrew Revkin, "Record Cold November–December in 48 Contiguous States," *New York Times,* January 6, 2001, p. A28.

56. California Senate president pro tem John Burton, for instance, argues that while electricity demand rose only 4 percent for the period May through December 2000 compared to the same period in 1999, total wholesale electricity costs rose by 328 percent. "California Lawmakers to Investigate Gas Costs, 'Manipulation,'" *Energy Report,* March 19, 2001, p. 9.

57. Ibid.; and Fereidoon Sioshansi, "The Summer Is Over; California's Market Problems Are Not," *Energy Informer,* October 2000, pp. 1–5.

58. The events of 2000 took place in the context of an underlying trend of demand rising faster than supply. During the 1990s demand grew at 3 percent per year throughout the West, and supply increased by 1 percent per year. But the trend came about because of the very large glut in capacity in the early 1990s. See "Staff Report to the Federal Energy Regulatory Commission," p. 5-3 and introduction to section on "Are Environmentalists the Culprit?" p. 28.

59. Quoted in Carl Levesque, "Emissions Standards: EPA, High Court, and Beyond," *Public Utilities Fortnightly,* January 1, 2001, pp. 46–47.

60. National Research Council, *Rethinking the Ozone Problem in Urban and Regional Air Pollution* (Washington: National Academy Press, 1991).

61. Gary Polakovic, "AQMD Moves to Overhaul Power Plant Emission Rules," *Los Angeles Times,* January 20, 2001, p. A23.

62. Levesque.

63. Krapels, p. 32.

64. Polakovic. In return for the waiver, power generators must install costly pollution control equipment over the next two years that would reduce emissions by 90 percent. Generators that remain in the RECLAIM market will be able to avoid buying credits by paying into a special account used to fund clean-air projects across the

region.

65. Quoted in Levesque.

66. Even customers who switched suppliers under the retail choice program and were not officially governed by price controls were insulated from the increases in wholesale prices because the stranded-cost recovery charge varies inversely with the actual costs of electricity. High electricity prices severely reduced the stranded-cost recovery charge. See Severin Borenstein, James Bushnell, and Frank Wolak, "Diagnosing Market Power in California's Deregulated Electricity Market," Program on Workable Energy Regulation Working Paper (PWP-064), August 2000, pp. 8–9, http://www.ucei.berkeley.edu/ucei/PDF/pwp064.pdf.

67. Stephen J. Rassenti, Vernon L. Smith, and Bart J. Wilson, "Using Experiments to Inform Privatization/Deregulation Movements in Electricity," *Cato Journal,* forthcoming; See also Steven Stoft, "The Market Flaw California Overlooked," *New York Times,* January 2, 2001, p. A19.

68. Eric Hirst, "Price-Responsive Retail Demand: Key to Competitive Electricity Markets," *Public Utilities Fortnightly,* March 1, 2001, pp. 34–41.

69. Smith and Emshwiller, "California's PG & E Gropes for a Way Out"; and Joskow and Kahn, p. 29.

70. Robert J. Michaels, "FERC's California Fix: Opportunities Lost and Found," *Public Utilities Fortnightly,* January 1, 2001, pp. 34–36. On December 15, 2001, FERC updated the order, and on March 9, 2001, FERC defined prices above 27.3 cents per kWh during stage 3 emergency periods in California in January 2001 as violating the soft price cap. See FERC press release, http://www.ferc.gov/news1/ pressreleases/refunds.pdf. On March 16, FERC defined prices above 43 cents per kWh during stage 3 emergencies in California in February 2001 as violating the soft price cap. See Craig D. Rose, "Leaders Fault FERC, Call for Tougher Action," *San Diego Union Tribune,* March 17, 2001.

71. Krapels, p. 30.

72. "California Generators Tell Hoeker They Acted Properly," *Energy Report,* December 4, 2000, p. 3.

73. Laura M. Holson and Richard A. Oppel Jr., "Trying to Follow the Money As Energy System Flounders," *New York Times,* January 12, 2001, p. A1.

74. "California Suffers Two Days of Rolling Blackouts," *Energy Report,* March 26, 2001, p. 1.

75. Nancy Vogel and Jennifer Warren, "California Utilities Were Overcharged, State Agency Says," *Los Angeles Times,* March 2, 2001, p. A3.

76. "Generators: Sales Just and Reasonable,'" *Energy Report,* April 2, 2001, p. 18.

77. "Feds Order Sales to Continue to California Utility," *Energy Report,* January 29, 2001, p. 4.

78. Todd S. Purdum, "Rolling Blackout Affects a Million across California," *New York Times,* March 20, 2001, p. A1.

79. Joskow and Kahn, Table 1, p. 8.

80. "White House Extends Emergency Orders As California Suffers under Threat of Blackouts for Second Week," *Energy Report,* January 29, 2001, p. 6.

81. Krapels, p. 33.

82. Joskow and Kahn, p. 30.

83. "FERC Takes Action to Repair Calif. Market, But Few Are Pleased," *Energy Report,* December 25, 2000, p. 4.

84. Van Vactor and Pickle, p. 36.

85. "Reliability Picture Bleak in California," *Energy Report,* May 7, 2001.

86. Rebecca Smith, John Emshwiller, and Mitchel Benson, "California Power Crisis: Blackouts and Lawsuits and No End in Sight," *Wall Street Journal,* January 19, 2001, p. A1.

87. Rebecca Smith, John Emshwiller, and Mitchel Benson, "California Is Hit with Series of Blackouts," *Wall Street Journal,* January 18, 2001, p. A1.

88. http://www.consumerwatchdog.org/ftcr/co/co000918.php3.

89. Federal Energy Regulatory Commission, "Report on Plant Outages in the State of California," February 1, 2001, as described in *Public Utilities Fortnightly,* March 1, 2001, p. 18.

90. Market power is defined as the withholding of some output by one or more producers to increase the price of other output owned by the same producers. In electricity markets this occurs when one owner shuts down a lower-cost generating unit in order to induce the usage of a high-cost unit that sets the market price for all other units with lower costs under similar ownership.

91. Borenstein, Bushnell, and Wolak, p. 34.

92. Joskow and Kahn, p. 20.

93. Scott Harvey and William W. Hogan, "Issues in the Analysis of Market Power in California," October 27, 2000, http://ksghome.harvard.edu/~whogan.cbg.ksg/HHMktPwr_1027.pdf. We do not discuss the California system's method for resolving transmission congestion, which Harvey and Hogan discuss on p. 8.

94. Ibid., pp. 9–14.

95. Ibid., pp. 4, 19; and Van Vactor and Pickle, pp. 40–41.

96. Stoft.

97. Tim Brennan, "The California Electricity Experience," Paper presented at the 20th Annual Workshop in Advanced Regulatory Economics, Tamiment, Pa., May 24, 2001, p. 31.

98. Nguyen T. Quan and Robert J. Michaels argue that, because generators have so many different opportunities to sell in the western market, the differentiation of market power from generators' simply pricing at their opportunity costs is impossible. See Nguyen T. Quan and Robert J. Michaels, "Games or Opportunities? Bidding in the California Markets?" *Electricity Journal* 14, no. 1 (January–February 2001): 99–108.

99. "Manifesto on the California Electricity Crisis," http://haas.berkeley.edu/news/california_electricity_crisis.html.

100. Federal Energy Regulatory Commission, Press release, March 9, 2001, http://www.ferc.gov/news/pressreleases/refunds.pdf. Stage 3 emergencies are declared by the California ISO when potentially available supply exceeds estimated demand by 1.5 percent or less.

101. California Energy Commission, "Wholesale Electricity Price Review," January 2001, Table 2, p. 4, http://www.energy.ca.gov/electricity/wepr/2001–01/index.html.

102. Jeff Gerth, "Some Evidence of Overcharges," *New York Times,* March 23, 2001, p. A14.

103. "FERC Orders Refunds or More Proof from California Suppliers," *Energy Report,* March 19, 2001.

104. The California ISO concedes the same but calculates that the average production cost for the most costly power plant necessary to meet demand was $180 per MWh in January 2001 and $260 per MWh in February. The estimates are lower than FERC's primarily because FERC was calculating only costs during peak-demand periods during power emergencies whereas the California ISO was calculating the weighted average of prices throughout the entire month. "California Claims $6.2 Billion in Excess Power Charges," *Energy Report,* April 2, 2001, p. 9.

105. "California Lawmakers to Investigate Gas Costs, 'Manipulation,'" *Energy Report,* March 19, 2001, p. 9.

106. See "California Messes Up," Editorial, *Wall Street Journal,* December 28, 2000, p. A10.

107. Daniel Eisenberg, "Which State Is Next?" *Time,* January 29, 2001, p. 45.

108. Alejandro Bodipo-Memba, "Deregulation Has Been Smooth—So Far," *Detroit Free Press,* January 18, 2001.

109. California Energy Commission, "Power Plant Projects before the California Energy Commission since 1979," January 16, 2001, http://www.energy.ca.gov/sitingcases/projects_since_1979.html.

110. Mark Arax and Terence Monmaney, "Power Plant Juggernaut Slowed by Internet Giant," *Los Angeles Times,* January 10, 2001; and Damien Cave, "Power and the People," January 30, 2001, http://www.salon.com/tech/feature/2001/01/30/power_regulation/print.html.

111. From 1999 to the present, the California Energy Commission approved permits for 13 plants with a combined generation capacity of 8,464 MW. The commission is currently reviewing 13 additional projects with a combined generation capacity of 6,989 MW (none of which would be up and running until 2004); another 14 projects totaling 8,080 MW have been publicly announced but not yet submitted for state review. Two dozen additional projects totaling 12,425 MW are known to be under consideration by the investment community. "California Agency Confirms State Will Be Short Power This Summer," *Energy Report,* April 9, 2001, p. 6.

112. John Greenwald, "The New Energy Crunch," *Time,* January 29, 2001

113. "Study: Power Short Despite Surplus," *Energy Report,* December 25, 2000, p. 10.

114. "CEC Chairman Says Summer 2001 Going to Be Tight," *Energy Report,* February 19, 2001, p. 5.

115. Hal R. Varian, "Economic Scene," *New York Times,* April 5, 2001, p. C2.

116. Peter Gosselin, "Most of West in Same Power Jam As California," *Los Angeles Times,* February 26, 2001.

117. Cave.

118. Nuclear power plants that were completed since the mid-1980s in the United States had capital costs that averaged about $3,000 per kW of generating capacity. See Mark Holt and Carl E. Behrens, "Nuclear Energy Policy," Congressional Research Service Issue Brief for Congress, March 22, 2001, p. 2, www.Cnie.org/nle/eng-5.html. Coal plants in the mid-1990s had capital costs of $1,501 per kW of generating capacity, and natural gas combined-cycle plants had capital costs of $419 per kW of generating capacity. Beamon and Wade, Table 3, p. x, discuss coal versus natural gas costs. In a competitive generation market rather than the traditional guaranteed rate-of-return environment, investors would build nuclear power facilities only if they believed that the price of electricity would exceed the marginal costs of a nuclear plant by sufficient margins over a long enough period of time so that the expected value of profits would be greater than profits from investments in the less capital intensive natural gas facilities. No nuclear plants have been ordered in the United States since 1978. It is not clear whether nuclear power was imprudent from the start or was made excessively costly by federal safety regulation (in the form of the Nuclear Regulatory Commission). In 1975 Resources for the Future projected that the total costs of nuclear plants in 1985–88 would be less than the total costs of equivalent coal plants. See William Spangar Peirce, *Economics of the Energy Industries* (Westport, Conn.: Praeger, 1996), pp. 216–17. A set of costly nuclear plants came online during the early 1980s, and electricity rates rose 60 percent from 1978 to 1982. See Caleb Solomon, "As Competition Roils Electric Utilities, They Look to New Mexico," *Wall Street Journal,* May 9, 1994, p. A1. By 1990 nuclear plants had total costs that were about double those for coal plants. Peirce, p. 216. Not all nuclear plants are more expensive than coal-fired plants. Peirce, pp. 217–18, reports that the least-expensive nuclear plants have total costs lower than the cheapest coal plants but that, at every other point in their respective cost distributions, nuclear plants are more expensive.

119. The San Onofre plant is located south of Los Angeles, and thus its output could not have been shipped into northern California because of daytime transmission constraints.

120. Brendan Kirby and Eric Hirst, "Maintaining Transmission Adequacy in the Future," *Electricity Journal* 12, no. 9 (November 1999): 64.

121. Kirby and Hirst, pp. 62–63.

122. Peter Behr, "Shortage of Power Lines Looms," *Washington Post,* February 20, 2001, p. A1.

123. Ibid.; Rebecca Smith and John Emshwiller, "California Isn't the Only Place Bracing for Electrical Shocks," *Wall Street Journal,* April 26, 2001; and Cambridge Energy Research Associates, *High Tension: The Future of Power Transmission in North America,* cited in "Lack of Investment Jeopardizes Power Grid, Study Says," *Energy Report,* October 16, 2000, p. 1.

124. Behr.

125. Douglas Jehl, "Weighing a Demand for Gas against the Fear of Pipelines," *New York Times,* March 8, 2001, p. A1.

126. Energy Information Administration, "A Look at Western Natural Gas Infrastructure during the Recent El Paso Pipeline Disruption," pp. 3-4, reports that capacity from Canada has grown by more than 50 percent since 1990.

127. See Stanley Horton, "Gas Pipelines: Solution, Not Problem," *Energy Perspective* 9, no. 2 (January 25, 2001): 3.

128. See ibid., pp. 3, 6.

129. Chip Cummins, "Natural-Gas Companies Discover California Is a Surprise Bonanza," *Wall Street Journal,* February 7, 2001, p. C1; and Energy Information Administration, "Status of Natural Gas Pipeline System Capacity Entering the 2000–2001 Heating Season," *Natural Gas Monthly,* October 2000, Table SR1, p. xiv, which reports that pipeline capacity from the southwest into California was only 55 percent utilized during 1999.

130. "Pipe Expansions on Tap to Supply California Power Plants," *Energy Report,* September 4, 2000, p. 7; and "Herbert: Power Sector Responsible for Spike in Gas Prices," *Energy Report,* March 5, 2001, p. 5.

131. For a representative article, see Yardley. See also Lynne Kiesling, "Getting Electricity Deregulation Right: How Other States and Nations Have Avoided California's Mistakes," Reason Public Policy Institute Policy Study no. 281, April 2001.

132. Energy Information Administration data cited by Greenwald, p. 43.

133. About 10 percent of all Pennsylvania residential ratepayers and users of a third of the total load have signed power contracts with nonutility power generators, a switchover rate that leads the nation. Commercial and industrial users, however, are migrating back to the utilities as wholesale prices rise higher than the default rates, a pattern consistent with that playing out today in California. Xenergy Corp., *Retail Energy Markets 2000,* reported in "Competition Developing

Slowly, Consultancy Finds," *Energy Report,* April 9, 2001, p. 9.

134. Krapels, p. 29.

135. Laurence D. Kirsch and Rajesh Rajaraman, "Assuring Enough Generation: Whose Job and How to Do It," *Public Utilities Fortnightly* April 15, 2001, pp. 40–41. Rhode Island and Pennsylvania have been slow in passing on costs.

136. Beamon and Wade, Table 3, p. x.

137. Ibid., pp. ix–xii.

138. "Electricity Demand to Grow Faster Than Expected, EIA Says," *Energy Report,* December 4, 2000, p. 2.

139. Remember that California had sufficient spare capacity until the hydro shortage occurred, and any installed-capacity requirement would necessitate adoption of some "measure" of hydro capacity, given that it can vary so much.

140. Brattle Group, "Shortening the NYISO's Installed Capacity Procurement Period: Assessment of Reliability Impacts," Report prepared for the New York Independent System Operator, May 2000, p. 3, http://www.nyiso.com/services/documents/studies/pdf/shortening_iso_inst_cap_procure_period_asses_rel_impacts.pdf.

141. Ibid., pp. 22–23.

142. Borenstein, "The Trouble with Electricity Markets," p. 3

143. Arthur S. De Vany, "Electricity Contenders: Coordination and Pricing on an Open Transmission Network," *Regulation* 20, no. 2 (Spring 1997): 48–51.

144. Gary Locke, "Caught in the Electrical Fallout," *New York Times,* February 2, 2001, p. A21.0

145. Sam Howe Verhovek, "California Gets Scant Sympathy from Neighbors," *New York Times,* January 26, 2001, p. A1.

146. William Booth, "States Locked into Grid Face Severe Energy Test," *Washington Post,* January 28, 2001, p. A3.

147. Gosselin.

148. Ibid.

149. Quoted in Booth.

150. Tom Gorman, "Vegas Lights Undimmed," *Los Angeles Times,* April 2, 2001.

151. Smith and Emshwiller, "California Isn't the Only Place"; and Locke.

152. One estimate of the profits for coal units in California when high-cost natural gas units are setting the market price comes from an offer of five times book value by an independent power producer (AES) for 56 percent ownership of a Southern California Edison coal-fired unit. See "News Digest," *Public Utilities Fortnightly,* March 1, 2001, p. 16.

153. Benjamin Zycher, "Political Meddling Made This a Mess—And Here They Go Again!" *Los Angeles Times,* January 17, 2001.

154. Joseph P. Kalt, *The Economics and Politics of Oil Price Regulation* (Cambridge, Mass.: MIT Press, 1981).

155. Peter D. Salins and Gerald C.S. Mildner, *Scarcity by Design: The Legacy of New York City's Housing Policies* (Cambridge, Mass.: Harvard University Press, 1992).

156. James Sterngold, "California Acting to Relieve Crisis," *New York Times,* January 13, 2001, p. A1.

157. Rene Sanchez, "California Promotes a New Lifestyle—Conservation," *Washington Post,* April 18, 2001, p. A1; and "California Retailers Must Cut Outdoor Lighting," *New York Times,* February 5, 2001, p. A18.

158. Steve Johnson, "State Reviews Draft Plan to Prohibit Energy Exports," *San Jose Mercury News,* March 11, 2001.

159. In 1998, for example, California exported 6,236 MWh and imported 51,125 MWh. See "Staff Report to the Federal Energy Regulatory Commission on Western Markets and the Causes of the Summer 2000 Price Abnormalities," Table 2-4, p. 2–7.

160. Sanchez, "California Promotes a New Lifestyle."

161. Wirl; J. D. Khazzoom, "Economic Implications of Mandated Efficiency Standards," *Energy Journal* 1, no. 4 (1980): 21–39; idem, *An Econometric Model Integrating Conservation in the Estimation of the Residential Demand for Electricity* (Greenwich, Conn.: JAI Press, 1986); idem, "Energy Savings Resulting from More Efficient Appliances," *Energy Journal* 8, no. 4 (1987): 85–89; idem, "Energy Savings Resulting from More Efficient Appliances: A Rejoinder," *Energy Journal* 10, no. 1 (1989): 85–89; Jeffrey Dubin, Allen Miedema, and Ram Chandran, "Price Effects of Energy Efficient Technologies: A Study of Residential Demand for Heating and Cooling,"

RAND Journal of Economics 17 (1986): 310–25; Eric Hirst, "Changes in Indoor Temperature after Retrofit Based Electricity Billing and Weather Data," *Energy Systems and Policy* 10 (1987): 1–20; H. D. Saunders, "The Khazzoom-Brooks Postulate and Neoclassical Growth," *Energy Journal* 13, no. 4 (1992): 131–48; F. P. Sioshansi, "Do Diminishing Returns Apply to DSM?" *Electricity Journal* 7, no. 4 (May 1994): 70–79; Paul Joskow, "Utility-Subsidized Energy Efficiency Programs," *Annual Review of Energy and the Environment* 20 (1995): 526–34; and David Greene and L. A. Greening, "Energy Use, Technical Efficiency, and the Rebound Effect: A Review of the Literature," Report to the Office of Policy Analysis and International Affairs, U.S. Department of Energy, December 1997. For a review of the literature on the rebound effect and automobile transportation (where the same dynamics apply), see David Greene, James Kahn, and Robert Gibson, "Fuel Economy Rebound Effect for U.S. Household Vehicles," *Energy Journal* 20, no. 3 (1999): 6–10.

162. Robert L. Bradley Jr., "Renewable Energy: Not Cheap, Not 'Green,'" Cato Institute Policy Analysis no. 280, August 27, 1997, p. 5.

163. See Wirl, particularly pp. 186–88.

164. The few detailed analyses of the phenomenon indicate that 50–60 percent of the participants in utility-sponsored energy efficiency programs would have invested in the technologies regardless of the subsidy. Wirl, pp. 120–26; and Paul Joskow and Donald Marron, "What Does a Negawatt Really Cost? Evidence from Utility Conservation Programs," *Energy Journal* 13, no. 4 (1992): 41–74.

165. Perhaps the most comprehensive study to date on the subject, undertaken by sympathetic researchers from the Denmark Institute for Local Government, found that among industrial consumers "the cost of finding electricity conservation projects is higher than the savings due to the realized investment." Mikael Togeby and Anders Larsen, "The Potential for Electricity Conservation in Industry: From Theory to Practice," in *Into the 21st Century: Harmonizing Energy Policy, Environment, and Sustainable Economic Growth* (Cleveland: International Association for Energy Economics, 1995), pp. 48–55. For similar analyses of residential ratepayers, see Albert Nichols, "How Well Do Market Failures Support the Need for Demand Side Management?" National Economic Research Associates, Cambridge, Mass., August 12, 1992, pp. 22–25; Ruth Johnson and David Kasserman, "Housing Market Capitalization of Energy-Saving Durable Good Investments," *Economic Inquiry* 21 (1983): 374–86; Kevin Hassett and Gilbert Metcalf, "Energy Conservation Investment: Do Consumers Discount the Future Correctly?" *Energy Policy* 21 (June 1993): 710–16; Gilbert Metcalf, "Economics and Rational Conservation Policy," *Energy Policy* 22 (October 1994): 819–25; and Avinash Dixit and Robert Pindyck, *Investment under Uncertainty* (Princeton, N.J.: Princeton University Press, 1994).

166. Nancy Vogel and Richard Simon, "DWP Earns Top Dollar on Recent Sale of Power," *Los Angeles Times*, February 16, 2001, p. A13.

167. Mitchel Benson, "Davis Report Fails to Reflect Highest Bids," *Wall Street Journal*, January 26, 2001, p. A2; and "California Enacts Bill Allowing State to Buy Power for Utilities," *Energy Report*, February 12, 2001, p. 7.

168. "California Regulators Approve Orders on IOUs, Conservation," *Energy Report*, April 9, 2001, p. 6. The *Wall Street Journal* earlier reported that the governor had reached agreement with 20 power generators to furnish the state with 8,900 MW for periods as long as 20 years but at an unspecified price. Rebecca Smith, Mitchel Benson, and John Emshwiller, "Major Kinks Emerge in Governor Davis' Plan to Power California," *Wall Street Journal*, March 8, 2001, p. A4.

169. Richard A. Oppel Jr., "California Lawmakers Debate Bill to Compensate Utilities," *New York Times*, January 27, 2001, p. B1.

170. "High Gas Prices Result of Over-Reliance, Senators Say," *Energy Report*, December 18, 2000, p. 6.

171. Mike Florio, senior attorney with the Utility Reform Network, said that, instead of raising rates, Davis should follow through on his threats to seize electricity generated by privately owned power plants. "They have got to get tough with these generators, and if that means commandeering the output of these plants, that's what he's got to do," Florio said. "The only way to stop these guys is to cut them off at the pockets." Quoted in Dan Morain, Nancy Vogel, and Stuart Silverstein, "PUC Chief to Urge Rate Hike, Favors 'Tiered' System," *Los Angeles Times*, March 24, 2001, p. 1.

172. Daniel McFadden, "California Needs Deregulation Done Right," *Wall Street Journal*, February 13, 2001, p. A26.

173. "Experts Concerned California Setting Dangerous Precedents," *Energy Report*, March 19, 2001, p. 10.

174. The exception arises if firms exercise market power. Under such circumstances, the greater the percentage of output the firm has sold in advance, the less the incentive for the firm to restrict output to

raise the spot price. And once firms face both forward and spot sale possibilities, competition in both markets becomes more vigorous. See Borenstein, "The Trouble with Electricity Markets," p. 8.

175. Ibid. Emphasis in the original.

176. Ronald Sutherland, "Natural Gas Contracts in an Emerging Competitive Market," *Energy Policy,* December 1993, p. 1196.

177. A 1981 Southern California Edison study forecast 1995 avoided electricity costs at 16.73 cents per kilowatt-hour, so the company willingly signed contracts to buy solar power at 15 cents per kWh even though the wholesale price of power in 1995 was actually about 2 to 3 cents per kWh. See Jeff Bailey, "Carter-Era Law Keeps Price of Electricity Up in Spite of a Surplus," *Wall Street Journal,* May 17, 1995, p. A1.

178. Don Oldenburg, "Losing a Good Natural Gas Deal," *Washington Post,* January 31, 2001, p. C4; James Sterngold and Matt Richtel, "Power Source Ends Direct Flow to California Businesses," *New York Times,* February 1, 2001, p. A15; "Ford Suing Dominion over Gas Deal," *Energy Report,* April 9, 2001, p. 14; Ben Fox, "Californians Return to Old Utilities," Associated Press, February 11, 2001; and Cave.

179. A typical analysis can be found in a report by Deutsche Banc's Alex Brown: "We continue to be confident that the question of excess generating capacity in the United States is a question of 'when,' not 'if.' Like many other asset-intensive commodity businesses, we expect developers to add too much capacity to the U.S. generation market." Alex Brown, "Electricity Supply & Demand in the U.S.," quoted in "Analysts See Excess Capacity by 2005," *Energy Report,* March 19, 2001, p. 15. There are two caveats, however. First, a sharp increase in populist demagoguery could trigger investors' fears of plant confiscation or mandated refunds, terminating projects now under way. This is already having an effect on new capacity. For instance, Calpine has withdrawn four of its five applications for permission to build peaking power plants that would have gone online this summer for exactly that reason. See "Calpine Drops Plans for California Plants," *Energy Report,* December 4, 2000, p. 9. Enron is also said to have scrapped plans for additional peaking generators. See "FERC Acts to Halt Californian 'Meltdown,'" *Energy and Power Risk Management,* December 2000, p. 4. Second, continued constraints on intrastate natural gas delivery systems due to regulatory inertia might worsen pipeline bottlenecks and thus inflate electricity prices despite increases in generating capacity and interstate gas pipeline delivery capacity.

180. The flood of investment in new power generation to serve the western market is also occurring in regional markets outside the West. Energy analyst Chris Seiple of RDI Consulting points out that 90,000 megawatts of new electricity generation capacity are scheduled to come online before the end of 2002. "There's an extraordinary, unprecedented power-plant building boom going on in this country," he notes. The Energy Information Administration of the Department of Energy likewise reports that 190,000 megawatts of new generating capacity will be built by 2004. The Electric Power Supply Association (a trade organization representing independent power generators) is a bit more conservative, but it, too, reports record investment in new generation, which is expected to produce 150,000 megawatts of new electricity by 2004. Margaret Kriz, "The Future Megawatt Factor," *National Journal,* April 21, 2001, p. 1170.

181. For a review of the size of North American natural gas reserves, see "Industry Confident U.S. Has Enough Gas to Meet Demand," *Energy Report,* March 5, 2001, p. 10; "Report Estimates U.S. Gas Supplies Good for 60 Years," *Energy Report,* April 9, 2001, p. 10; "Canadians Cheer White House Pro-Gas Remarks," *Energy Report,* April 9, 2001, p. 12; and Judith Gurney, "U.S. Faces Natural Gas Price Shock," *Energy Economist* 229 (November 2000): 15–18. For a discussion of technological advances on the near horizon that could dramatically expand natural gas supplies if prices stay high, see Jennifer Considine et al., "North American Natural Gas Markets," *Oxford Energy Forum,* February 2001, pp. 7–9.

182. Mark Golden, "Power Points: California Governor Fiddles As Summer Likely to Burn," Dow Jones Energy Service, February 26, 2001; and "California Heads from Crisis toward Calamity, Experts Say," *Energy Report,* March 19, 2001, p. 1.

183. Quoted in Smith, Benson, and Emshwiller, "Major Kinks Emerge."

184. As we wrote this paper, the California Public Utilities Commission did increase rates 36 percent and made their temporary 10 percent hike permanent. The governor initially distanced himself from the increase but later supported it. See Todd S. Purdum, "In California, Reversal on Energy Rates," *New York Times,* April 6, 2001, p. A11.

185. James Bushnell and Erin Mansur, "The Impact of Retail Rate Deregulation on Electricity Consumption in San Diego," Program on Workable Energy Regulation Working Paper (PWP-082), April 2001, p. 4, http://www.ucei.berkeley.edu/ucei/PDF/pwp082.pdf.

186. Ibid., p. 17. Steven Braithwait and Ahmad Faruqui, "The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response," *Public Utilities Fortnightly,* March 15, 2001, p. 60, report elasticity estimates of .07 to .135 (a reduction in demand of 7 to 13.5 percent for a doubling of prices).

187. "Experts Concerned California Setting Dangerous Precedents," *Energy Report,* March 19, 2001, p. 11.

188. Matthew Wald, "Gasoline Use Fell Last Year, Oil Group Says," *New York Times,* January 20, 2001, p. B1.

189. Quoted in Ibid.

190. McFadden.

191. Severin Borenstein, "Frequently Asked Questions about Implementing Real-Time Electricity Pricing in California for Summer 2001," March 2001, http://www.ucei.org/PDF/ faq.pdf.

192. Ahmed Faruqui et al., "California Syndrome," *Regulation* , forthcoming.

193. Ibid.

194. Robert J. Michaels, "Can Nonprofit Transmission Be Independent?" *Regulation* 23, no. 3 (Summer 2000): 61–66.

195. For a detailed examination of how such a regime could be structured, see Douglas Houston, "User-Ownership of Electric Transmission Grids: Towards Resolving the Access Issue," *Regulation* 15, no. 1 (Winter 1992): 48–57.

196. Rene Sanchez, "California Crisis Has Residents Seething," *Washington Post,* February 11, 2001, p. A1.

197. John McCaughey and Kennedy Maize, "Is California Too Late for the Learning?" *Energy Perspective* 9, nos. 3–4 (February 8, 2001): 2.

198 "Manifesto on the California Electricity Crisis," http://haas.berkeley.edu/news/california_ electricity_crisis.html.

Published by the Cato Institute, Policy Analysis is a regular series evaluating government policies and offering proposals for reform. Nothing in Policy Analysis should be construed as necessarily reflecting the views of the Cato Institute or as an attempt to aid or hinder the passage of any bill before congress. Contact the Cato Institute for reprint permission. Additional copies of Policy Analysis are $6.00 each ($3.00 each for five or more). To order, or for a complete listing of available studies, write the Cato Institute, 1000 Massachusetts Ave., N.W., Washington, D.C. 20001, call toll free 1-800-767-1241 (noon - 9 p.m. eastern time), fax (202) 842-3490, or visit our website at www.cato.org.