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CALIFORNIA'S RESTRUCTURING

Turning Opportunity into Risk

CALIFORNIA UTILITIES BEFORE RESTRUCTURING

At the beginning of the saga, California's electricity system operated in a manner similar to electricity systems throughout the United States. It included three large investor-owned utilities, collectively selling most of the electricity in California. Each investor-owned utility had a franchise in one of three separate parts of the state—Pacific Gas and Electric Company (PG&E) in Northern and central California, Southern California Edison (SCE) in coastal, central, and Southern California, and San Diego Gas and Electric (SDG&E) in San Diego. In addition, there were several much smaller investor-owned utilities, several electric co-ops, and numerous municipal utility systems, the largest of which were the Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD) (see Table 2.1).

The investor-owned utilities serve 78 percent of the California customers and the municipal utilities serve 22 percent. The electric co-ops and the federal agencies collectively serve less than 0.1 percent of the customers. In terms of total megawatt-hours (MWh) of electricity, the investor-owned facilities sell 72 percent, the municipal utilities 24 percent, and the federal agencies 3 percent (see Table 2.1).

The average price of electricity was similar for investor-owned utilities and municipal utilities. As measured by the average revenue

TABLE 2.1

Retail Sellers of Electricity in California: 1999

Electric Utility	*Number of Customers*	*Revenue ($ Thousands)*	*Sales (MWh)*	*Avg. Revenue ($/MWh)*
Investor-owned Utilities				
Pacific Gas & Electric Co.	4,535,909	6,785,994	70,186,749	97
PacifiCorp	41,473	53,324	778,531	69
San Diego Gas & Electric Co.	1,184,844	1,415,141	14,718,306	96
Sierra Pacific Power Co.	43,877	38,826	506,280	77
Southern California Edison Co.	4,213,562	6,692,164	67,206,530	100
Southern California Water Co.	20,988	13,275	127,135	104
Total	10,040,653	14,998,724	153,523,531	98
Municipal Utilities				
Alameda, City of	32,569	38,979	371,326	105
Anaheim, City of	105,755	220,932	2,416,302	91
Azusa, City of	14,549	21,072	233,213	90
Banning, City of	9,523	13,501	118,821	114
Biggs, City of	656	787	7,340	107
Burbank, City of	51,488	106,360	1,029,003	103

Colton, City of	16,893	26,176	266,108	98
Glendale, City of	83,100	112,701	1,071,277	105
Gridley, City of	2,191	2,315	26,824	86
Healdsburg, City of	4,903	7,397	69,904	106
Imperial Irrigation District	93,486	193,531	2,384,949	81
Lassen Municipal Utility District	10,162	12,227	136,909	89
Lodi, City of	23,776	38,329	391,276	98
Lompoc, City of	14,455	12,336	125,717	98
Los Angeles, City of	1,385,396	2,080,736	20,056,691	104
Merced Irrigation District	148	5,362	113,305	47
Modesto Irrigation District	92,229	136,566	2,164,620	63
Needles, City of	2,907	4,907	60,967	81
Palo Alto, City of	27,723	66,503	1,124,025	59
Pasadena, City of	58,378	129,657	1,129,383	115
Redding, City of	38,295	68,937	683,493	101
Riverside, City of	92,644	160,773	1,647,509	98
Roseville, City of	36,243	60,003	819,570	73
Sacramento Municipal Utility District	503,615	722,046	9,284,751	78
San Francisco, City & County of	9	40,588	728,342	56
Santa Clara, City of	47,524	194,782	2,491,714	78
Shasta Lake, City of	3,916	5,004	65,305	77
Trinity Public Utilities District	6,464	5,606	77,498	72

Table 2.1 *(continued)*

Electric Utility	*Number of Customers*	*Revenue ($ Thousands)*	*Sales (MWh)*	*Avg. Revenue ($/MWh)*
Truckee Donner Public Utility District	10,324	8,615	122,029	71
Tuolumne County Public Power Agency	30	1,194	23,162	52
Turlock Irrigation District	66,456	105,366	1,415,162	75
Ukiah, City of	7,298	13,606	106,303	128
Vernon, City of	2,026	55,056	1,161,173	47
Total	2,845,131	4,671,950	51,923,971	90
Electric Co-ops				
Anza Electric Co-op, Inc.	3,468	5,138	34,693	148
Plumas-Sierra Rural Electric Co-op.	6,067	9,607	118,818	81
Surprise Valley Electric Corporation	3,923	4,594	88,802	52
Valley Electric Association, Inc.	29	337	7,081	48
Total	13,487	19,676	249,394	79
Federal Agencies				
Bonneville Power Administration	10	6,365	264,515	24
Western Area Power Administration	98	94,914	6,019,473	16
Total	108	101,279	6,283,988	16
State Total	12,899,380	19,791,632	211,981,140	93

SOURCE: Energy Information Administration per MWh sold, the average retail price of electricity sold by the municipal utilities (including delivery services) was 8 percent less than it was for investor-owned utilities. Retail prices for municipal utilities varied over a wide range, from 30 percent above to 51 percent below the average investor-owned utility price. The largest municipal utility, LADWP, had an average price (more precisely, average revenue per MWh) 6 percent above the investor-owned utilities' average.

Each investor-owned or municipal utility operated as a local monopoly, selling electricity in its own exclusive franchise area, with no direct retail competition from other electricity sellers. The large investor-owned utilities, as well as some of the municipal utilities, were vertically integrated to include three separate functions: generation, transmission, and local distribution. A typical investor-owned utility generated most of its electricity (generation), moved that electricity on transmission lines to local areas where it was needed (transmission), and sold that electricity to industrial, commercial, and residential users (local distribution). Some municipal utilities operated as only local distribution companies; some participated in one or both of the other two functions—generation and transmission.

For investor-owned utilities, almost all significant financial decisions involving any of the three functions were subject to the jurisdiction and control of the statewide regulatory body, the California Public Utilities Commission (CPUC). Customers paid retail prices for electricity based on operating costs plus a regulated rate of return on the prudently incurred "used and useful" invested capital. The CPUC would review whether costs were prudent and determine the "fair" rate of return on invested capital that was meant to approximate a normal rate of return for companies facing equivalent risk. Thus pricing was based primarily on cost of service and only secondarily on market conditions.[1]

The significant decisions made by the publicly owned municipal utilities were subject to the jurisdiction and control of their

[1]Market conditions have a secondary role because of the dynamic nature of the rate-setting process. Each rate case sets retail prices based on conditions in some base year or years. These rates stay in place until the next rate case. Thus if sales increase in the future beyond expectations, profits for the utility will rise, and vice versa if sales decline. This provides an incentive to delay rate cases when sales and profits are higher than expected and to quickly initiate rate cases when sales and profits are low. In addition, the actual system creates incentives to block distributed generation investments that would reduce sales and to go slow on energy efficiency investments that would reduce sales of electricity.

appointed or elected governing bodies. Thus, their strategies could be based on local decision making, rather than on statewide regulations. They typically were operated, however, so that over a span of several years their revenues roughly equaled their total costs of operation. Thus, for municipal utilities as well as for investor-owned utilities, pricing was based primarily on cost of service and only secondarily on market conditions.

This particular type of industrial organization—utilities operating as regulated monopolies—had been justified for many decades by the increasing-returns-to-scale[2] nature of electricity generation, transmission, and distribution.

Retail distribution (the provision of delivery services: wires, transformers, and other physical equipment) provides the most obvious example of increasing returns to scale in the electric industry. A customer could double the amount of electricity used with no increase in the cost of providing wires to a home. Equivalently, if two competing companies were each to run electric wires down the same streets to compete for customers, total cost and cost per customer would increase even with no change in the quantity of electricity delivered. Cost would be lowest if only one company were providing the wires, transformers, and other physical equipment for local distribution of centrally generated electricity. Thus local distribution of centrally generated electricity is generally considered to be a natural monopoly and, as such, is typically allowed to operate as a monopoly franchise, subject to regulatory oversight, in California, as in other states.[3]

As distinct from electricity distribution services, retail electricity is not characterized by increasing returns to scale. To double the amount of electricity sold, a retailer would need to double the amount of electricity acquired at wholesale. For wholesale electricity prices held fixed, doubling the acquisition of electricity would double the total cost of acquiring the electricity. Thus the cost per MWh sold at retail neither increases nor decreases (at

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[2]Increasing returns to scale characterizes an industry if increasing the size of individual firms reduces the average cost of the product.

[3]This argument cannot legitimately be generalized to include distributed generation of electricity at the point of end use. Distributed generation includes both the generation and distribution function. In some cases, the addition of distributed generation to systems with existing distribution networks may reduce total system costs. Nevertheless, natural monopoly arguments have been used by some utilities to limit competition from distributed generation.

least not significantly) as the scale of retail operations changes. Retail sale of the commodity (electricity itself) is not characterized by increasing returns to scale, and thus the retail electricity sales function cannot be viewed as a natural monopoly.

In principle, the regulatory system could logically separate delivery services from the retail sales of electricity itself. The retail sales function would be amenable to organization as a competitive industry even though the delivery function was not organized in a competitive market structure.

Typically, however, delivery services and the electricity were bundled: customers were charged a price for the combination of electricity and delivery services. In this way, the natural monopoly franchise for delivery services was extended into monopoly franchises for delivery services and for electricity. California operated this way, as did most states.

Increasing returns to scale also characterizes the transmission of electricity, up to a point. Electricity moves on high-voltage transmission lines integrated into an electricity grid. A significant cost of this transmission system is paying for the right-of-way on which to build transmission lines. When the transmission lines are operating well below capacity, it would cost little to move additional electricity through these lines. Even at capacity, installing additional high-voltage wires on an existing transmission link costs substantially less than required to establish the link in the first place. Thus transmission also seems to be appropriately organized as a monopoly along a given transmission path, as it is in California.

Finally, electricity generation also seemed to have the increasing returns to scale characteristic of a natural monopoly. For many years the conventional wisdom was that the larger the electric generating plant, the lower the overall cost of electricity generation. Bigger was cheaper. This increasing returns to scale characteristic of electricity generation led to the common belief that electricity generation should be organized as a monopoly.

Given that all three components of the electricity supply system were operated as monopolies, there was a tendency, although not a necessity, for these three elements to be vertically integrated into a single company.[4] The first reason for this was the need for coordination in planning for capital investments and

[4]Many municipal utilities were not vertically integrated even though all three large investor-owned utilities were.

operations. The amount of electricity sold by the distribution firm determined the amount of generation and transmission capacity needed. The location of transmission facilities and generation facilities required coordination to minimize overall cost. This need for coordination and for appropriate information flows helped justify combining these three entities into one vertically integrated company.

A second, and related, reason for vertical integration was based on reducing transactions costs. Three separate monopolies, all integrated into one supply chain, might choose to operate so as to gain financial advantages over one another. Although this strategic problem could be controlled through the regulatory process, integrating the three entities into one company would reduce or eliminate those incentives and the resulting need for regulatory oversight.

Although the investor-owned utilities in California, and in the rest of the nation, operated as vertically integrated monopolies, they did purchase some electricity from external sources. These purchases involved a mix of long- and medium-term contracts, plus spot market purchases or sales, to match unexpected variations in their sales of electricity. In particular, California utilities had long-term contracts to purchase hydroelectric power from the Bonneville Power Administration (BPA), a federal power-marketing agency. BPA sells power generated primarily from federal hydroelectric projects in the federal Columbia River Power System.[5] Both municipal utilities and investor-owned utilities also had other contracts to purchase electricity from federal projects. California traditionally sold electricity to entities in the Pacific Northwest in the winter, when demand there peaked, and purchased electricity from the Pacific Northwest during the summer, when California demand peaked. Other than these low-priced sources of electricity, however, California's investor-owned electric utilities historically tended to acquire electricity from their own generating units.

THE CHANGING FEDERAL REGULATORY STRUCTURE

PURPA

In 1973, energy markets, particularly oil markets, were severely shaken by the sudden jump in oil prices resulting from the Organization of Petroleum Exporting Countries (OPEC)–organized

[5]The largest of these federal dams is the Grand Coulee Dam.

reduction in world oil production. President Richard Nixon declared "Project Independence," and the United States began searching for means of reducing its dependence on oil and natural gas. In 1973, oil accounted for about 20 percent of the fossil fuels used for electricity generation; natural gas accounted for another 20 percent. Although natural gas was not imported in large quantities, U.S. policies were shaped by a general belief that natural gas would be in short supply and that, as a "premium fuel," natural gas should not be used for electricity generation. The efforts to reduce the use of oil and natural gas left nuclear power, coal, and various renewable sources of energy as alternative primary sources, plus energy-efficiency investments that provided energy services using smaller amounts of electricity.

In response to these public policy goals, Congress passed several laws designed to promote nuclear power, coal, energy efficiency, and small-scale renewable energy sources (wood waste, solar, wind) and to discourage the use of oil and gas.[6] Many people, however, feared that utilities would favor their own generation and avoid adopting the generation technologies Congress wished to promote. The Public Utility Regulatory Policies Act (PURPA) of 1978 was enacted primarily to promote development of small-scale renewable sources of energy for electricity generation. Cogeneration[7] was included as a means of more efficiently converting primary energy into electricity and usable heat. PURPA mandated state regulatory commissions to establish procedures requiring electric utilities to interconnect with and buy capacity and energy offered by any nonutility facility that qualified under PURPA. These so-called qualifying facilities, or QFs, were typically

[6]The Powerplant and Industrial Fuel Use Act of 1978 includes a provision: "Except to such extent as may be authorized under part B, no new electric powerplant may be constructed or operated as a base load powerplant without the capability to use coal or another alternate fuel as a primary energy source." "Alternative fuel" within the definition of that act excludes oil and natural gas. The act explicitly did not apply to nuclear-powered plants. And it provided a permanent exemption for cogeneration plants. (U.S. Code Title 42, Chapter 92, Section 8301–8354.)

[7]Cogeneration units are those that both generate electricity and use the energy not converted to electricity for purposes such as space or water heating or industrial process heating. In so doing, a large fraction of the input energy is harnessed for desirable functions. Many cogeneration plants are based on natural gas, but PURPA promoted cogeneration based on any primary fuel.

small generating facilities based on renewable energy, waste products, or natural-gas-fired cogeneration units.

Utilities were required by PURPA to pay a price for electricity from QFs equal to the "avoided cost" of electricity generation, which was meant to be the total costs that a utility would avoid by purchasing electricity from these small alternative sources. The state regulatory commissions were allowed by PURPA to interpret the dollar price that corresponded to avoided cost and the precise conditions under which the electricity and capacity must be purchased.

Impacts well beyond the limited public policy goal that motivated its passage were achieved by PURPA. PURPA started to change the structure of the electric industry, providing the first challenge to the tightly integrated vertical monopoly structure.

OPENING TRANSMISSION NETWORKS

With the success of PURPA, by the mid-1980s analysts realized that it was not necessary to operate electricity generation as a regulated monopoly and that there was an opportunity to create a competitive electric generation industry. By then, utility executives understood the high capital costs of nuclear power; no utilities were proposing new nuclear power plant construction. Natural gas had become broadly available throughout the United States and was no longer seen as a premium fuel; its use in new electricity-generating plants was no longer prohibited under federal law.[8] Thus it became possible to construct gas-fired power plants. Combustion turbines had become more efficient, particularly in a combined-cycle mode. These turbines could be built in modules—one turbine, then another, then a steam cycle. This modular construction allowed for more flexibility and the construction of smaller, very efficient plants. However, although utilities typically had not been taking advantage of that opportunity, once PURPA opened the way for independent power producers, these firms began exploiting the profit opportunities of using the waste heat from turbines in combined-cycle plants. Thus the assumption that electricity generation exhibited increasing returns to scale was no longer seen as valid. Consequently, the idea

[8]In 1987, the Powerplant and Industrial Fuel Use Act was amended to permit electric utilities to burn oil or natural gas in new baseload generating facilities, if the plants could permit future voluntary conversion to coal. Even before that time, however, exemptions to the restriction had been routinely granted.

of electricity generation as a natural monopoly was no longer consistent with technical reality.

However, utilities still controlled all electricity transmission lines, which were still seen as natural monopolies. A utility that wished to stifle competition in electricity generation could do so by refusing to allow its competitors to transmit electricity along its transmission lines. Thus creating a truly competitive market for electricity generation required federal officials to deal with issues of utility control of transmission lines.

The first step was the Energy Policy Act (EPACT) of 1992. Among its many provisions, EPACT opened access by nonutilities to the transmission networks. And in 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888, which much more generally opened transmission access to nonutilities. These regulatory changes together started to transform the electricity transmission system into a common carrier system. With EPACT and Order 888, it became much more difficult to control electricity generation markets by controlling electricity transmission. Utilities still made the investment decisions for transmission facilities and thus could still exercise some control over generation markets, but this form of control was less effective than direct control over access to transmission lines. These two changes were fundamental for establishing the opportunity for wholesale competition in electricity.

IMPACTS ON CALIFORNIA ELECTRICITY BEFORE RESTRUCTURING

In California, the CPUC aggressively implemented PURPA, setting high prices for electricity purchased by the investor-owned utilities[9] and requiring the investor-owned utilities to sign contracts based on standard offers with guaranteed prices that rose sharply over time.[10]

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[9]Since the CPUC did not regulate the municipal utilities, these high prices were not relevant to these entities.

[10]Under Interim Standard Offer No. 4 (ISO4), a QF based on renewable energy could sign a contract based on a fixed forecast of future electricity price. Such a QF entering a contract would be guaranteed $57/MWh in 1985, $81/MWh in 1990, and $109/MWh in 1994. After ten years the contract price reverted to the short-run avoided cost, which typically would be far lower than the fixed-price guarantee. Gas-fired cogeneration units were not treated nearly as generously but were generally paid an annual average of about $25/MWh for capacity and about $25–$30/MWh for energy.

The financial incentives and guaranteed market for QF electricity, coupled with tax incentives established by the federal government, created a significant industry of renewable electricity generation in California, including wind farms and wood waste–fueled generators. These policy changes also led to large increases in cogeneration capacity,[11] which was largely natural gas–fired. By the end of 1994, 20 percent of the electricity generation capacity in California was from QFs, 11.5 percent of which was cogeneration; 8.3 percent was renewable generation capacity, the largest inventory of renewable generation capacity in the nation.

However, with long-term contractual obligations to purchase electricity from QFs at a high cost, by the early 1990s the utilities were facing a high average cost of electricity generation. In addition, California utilities had invested in nuclear power plants, whose construction costs turned out to be far greater than initially predicted, further increasing the average cost of electricity generation.

These factors together helped make California's retail prices among the highest in the nation. For retail prices,[12] or, more precisely, a state-by-state comparison of the 1998 average revenue per kilowatt-hour (KWh, measured in cents per KWh) sold to residential customers, see Figure 2.1. Only in California, Alaska, Hawaii, and the northeastern states did average retail prices exceed 8 cents/KWh ($80/MWh). California's average revenue was 9 cents/KWh ($90/MWh).

MOTIVATIONS FOR CALIFORNIA ELECTRICITY DEREGULATION

Generation/Wholesale Markets

The high retail price of electricity in California, relative to that of the rest of the nation, was one argument for California's electric system being deregulated to create a more competitive, and

[11]Cogeneration now is the single biggest source of PURPA electricity-generation capacity in California. Of the roughly 10,200 megawatts (MW) of total QF nameplate capacity in California in 2001, about 5,700 MW came from cogeneration and 4,500 MW from renewables such as wind or organic wastes. (Data from California Energy Commission database of electricity-generating plants on-line in California.)

[12]Source: U.S. Department of Energy, Energy Information Administration, *Electric Power Annual* 1 (1998).

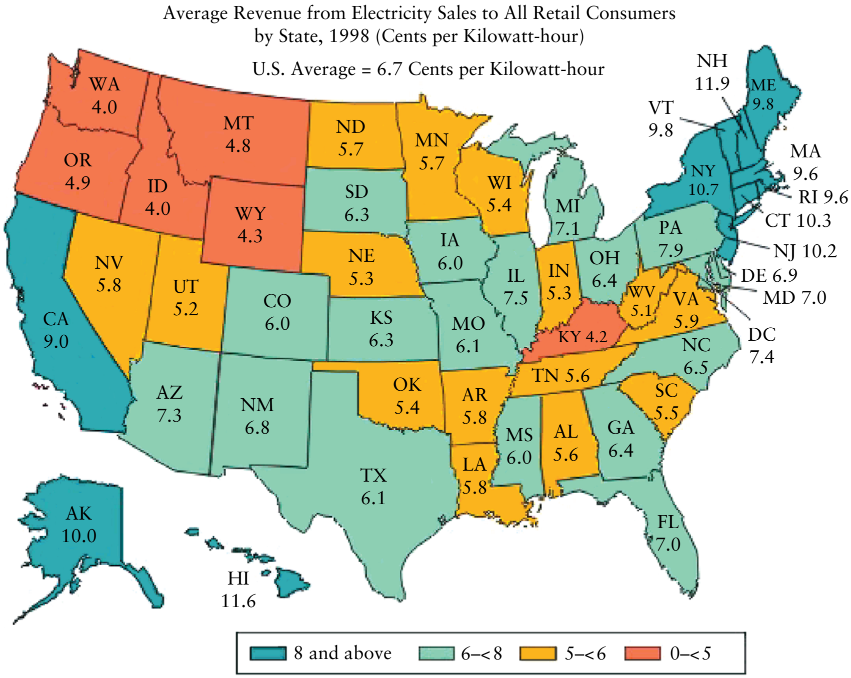

FIGURE 2.1: Average Revenue from Electricity Sales to All Retail Consumers

SOURCE: Energy Information Administration, U.S. Department of Energy

presumably lower-cost, electricity system. The concern about high retail costs became an argument about electricity generation because major contributors to the high retail price in California were the high average cost of generating electricity and the high prices embedded in contracts for purchasing electricity under PURPA contracts. Many advocates of electricity-generation deregulation expected deregulation to reduce retail prices of electricity quickly.

But this expectation was based on a fundamental fallacy, implicitly assuming that deregulation in the present could somehow correct the historical problems that had led to the high generation costs and the high costs of purchasing bulk power under contracts. The costly investments in nuclear power plants and the long-term contracts for QFs, however, could not be reversed. At the time of the restructuring debate, the state was no longer investing in new nuclear power plants. New cogeneration plants and renewable energy investments were being made when such investments were expected by their developers to be economically attractive. The high-price standard offers under PURPA were no longer required for new contracts. If the problem was higher prices caused by the historical nuclear power plant investments and QFs contracts, restructuring was not the answer.

Moreover, if California could have gone back in time to restructure the wholesale electricity markets before it invested in the nuclear power plants and the QF contracts, it could probably not have avoided those high electricity costs. After oil prices jumped in the mid-1970s and early 1980s, oil was no longer an economically attractive source of energy for electricity generation. Initially, natural gas was not available in large quantities, and beginning in 1978, federal law precluded its use in new baseload electricity-generating units. The sites for developing high-head hydroelectric power plants in California had already been well developed. Coal was not a good option: California had no indigenous coal; cooling water needed for coal-fired units was limited, except on California's coasts; building new railroad lines to haul coal to California's coasts would have been very costly; the environmental impacts of coal-fired facilities on California's coastline would have been unacceptable; and the problems of transporting vast quantities of coal to those plants by railroad would have been overwhelming. The United States had been investing in nuclear power plants believing that nuclear power would be the least costly method of generating electricity, which turned out to be false. Moreover, the geologically active faults near the California coastline made designing and constructing nuclear power plants difficult. Thus, the most attractive options for new generation capacity were renewables and cogeneration. Those supply sources, combined with energy efficiency programs—programs that reduced the need for new generation—were probably the best choices.

The cost of contracts to purchase electricity from QFs could have been significantly lower if the CPUC had chosen a more realistic calculation of the avoided cost of electricity. And even restructuring electricity markets was unlikely to have forced CPUC away from its politically inspired high calculations of avoided cost.

In short, even if California could have gone back in time and restructured electricity markets in the mid-1970s, whether the particular factors that led to high electricity prices in California would have been significantly different as of the 1990s is dubious.

The more subtle argument, however, was that deregulation would reduce costs, although the cost reductions would be gradual, not the instant cost decreases some expected. The regulatory system probably did not provide strong enough incentives for utility-owned electricity generators to minimize costs and thus probably did not lead to the lowest-cost mix of energy generation technologies. Some utilities were probably favoring their own generation over generation by independent power producers and thus not minimizing cost. There remained incentives and opportunities for utilities to block distributed generation and to rely instead on central-station power, even if distributed generation had lower overall costs. Whether the regulated system was leading to too much investment in capital-intensive generation, and too much investment in generation relative to expenditures on demand management, was a more subtle debate. However, economists and other industry analysts argued that creating competition could change economic incentives facing the utilities and thus gradually reduce costs of electricity generation, which in turn would gradually reduce retail prices. This argument, although not proven, was probably valid, even though the hope of fast cost savings was probably never realistic.

In addition, many asserted that the expansion of wholesale markets would encourage investment by independent power producers in new generating capacity. In the early 1990s there was a surplus of California electricity-generating capacity (including expected electricity imports), albeit a small one. However, most analysts anticipated that the healthy California economy would continue to need more electricity over the years and doubted whether the old regulated system would be responsive enough to those needs. Many also argued that the old regulated system would lead to utilities discouraging new investment by independent power producers.[13] The

[13]Traditionally rate-of-return–regulated utilities invest in more generation than might be expected under a purely competitive regime. However, their incentive to reduce purchases from independent power producers could reduce total investment in new generation. For example, in 1993, the CPUC directed the utilities to issue a solicitation for a little over 1,000 MW of electricity. Bids by QFs undercut the costs of the utility projects with a price of about $44/MWh. But SCE (and to a lesser extent, SDG&E) successfully resisted entering the new contracts, asserting that no new capacity was needed, since conservation could meet any new needs.

expansion of a competitive wholesale market was intended as a long-term solution to a long-term problem.

The nationwide trends toward smaller, modular electric generation units were evident in California. During the 1980s the combination of broadly available natural gas and technological change had led independent power producers in California to invest in smaller gas-fired plants that could be distributed throughout the state. Electricity thus could be generated close to where it was needed, saving costs of expanding electricity transmission lines.[14] It had become clear in California that bigger was no longer cheaper and thus that electricity generation was not a natural monopoly. Since most new investment in electricity generation was by independent power producers, not utilities, the deregulation of electricity generation and the expansion of wholesale markets supported this pronounced trend.

Thus, there was the opportunity in California to deregulate electricity generation and to expand the scope of the existing competitive portion of the industry. Expanding competition in electricity generation was expected to create incentives for cost cutting, to encourage investments in new generating capacity by independent power producers, and to provide a flexible system for a dynamic California economy.

Stranded Costs

The prospect of low wholesale electricity prices, coupled with high costs for some past investments, created challenges for deregulation. If future costs would be low for new generation, then future wholesale prices could be expected to be low as well. However, with low wholesale costs, the existing high-cost generating units might no longer be economically viable in a competitive environment. The investment costs incurred by the utilities in constructing these plants would be "stranded." Utilities would incur losses because of these stranded costs, absent policy intervention.

The issue of stranded costs was not fundamentally a problem of "going forward" costs—future total costs of electricity generation ignoring sunk costs—even if those costs might be very high for

[14]Such localized, small-scale generation could also reduce the need for new transmission lines with their very large costs and their possible environmental impacts.

some of the units. If wholesale electricity prices turned out to be lower than the per MWh going forward costs of these plants, in a competitive environment the plants would shut down and their entire remaining book value would be a loss to their owners. However, such plants *should* be shut down for economic efficiency reasons: the value of electricity they produced would be less than the additional cost to produce that electricity. By contrast, if the wholesale electricity prices turned out to be higher than the going forward costs of these plants, they could sell electricity at the wholesale price and generation would thus be more profitable than shutting down. These plants could compete in a market environment, as would be desirable for economic efficiency. However, there would still be a fixed loss: the owner would not be able to recover all of the remaining book value. Although the loss would be strictly less than the book value, it might still be large.

These fixed losses were sunk costs and therefore not expected to influence the market-clearing price. But someone would have to bear the losses. Who should bear these losses—the utilities or their customers—was a politically important issue. Thus, the issue of stranded costs was simply who should bear the burden of those fixed costs.

Given the issue of stranded costs, several possible alternatives were consistent with the deregulation of generation. One would be to allow the utility to include those costs in retail prices, keeping the retail prices high, just as they would be absent restructuring. That solution would motivate customers to bypass those utilities with large stranded costs and purchase directly from generators or generate electricity themselves, say, by investing in cogeneration units. The customers most able to do so would be the large industrial users of electricity that could go directly to new electricity generators and could enter contracts based on the lower costs of new generation or could invest in cogeneration units near the point of use. If enough large customers bypassed the utilities, these utilities would sell electricity primarily to residential and small commercial consumers; small users would thus pay most of the stranded costs. Many consumer groups, not surprisingly, opposed this option.

Another option would be to require the utility to write off the assets as losses, requiring stockholders to face the consequences of stranded costs. The utilities argued persuasively that it would be fundamentally inequitable for their investors to bear all the stranded costs of long-term contracts and generating investments that, in many instances, were forced on them under the old "regulatory compact." They argued that they should be able to recover all of these "prudently incurred" investments because there had been an implicit contract between the regulators and the utilities under which utilities would make investments to serve the needs of ratepayers and ratepayers would pay back the costs of those investments, plus a fair rate of return on the investments, over the life of the equipment. By contrast, those who advocated requiring the utilities to bear those losses argued that the utilities were not blameless in the past investments, that they had proposed most of the investments themselves, that they had mismanaged the long-term contracting for QFs, and that many of the investments were simply mistakes by the utilities. Their recommendation was that the investors in those utilities, not the ratepayers, should be required to bear the stranded costs.

This debate—who should pay the burden of historical investments, now uneconomical—became central to the subsequent regulatory hearings and legislation. In addition, calculations of the magnitude of stranded costs, by necessity, include many subjective elements. No one could predict with any confidence future sales prices over time of wholesale electricity or future natural gas prices. Thus issues of how to calculate stranded costs and how to reduce the need to calculate stranded costs also remained important. Once the crisis occurred, the theme returned. Looking to the future, this class of issues remains central to the policy options, because the State of California incurred large financial obligations during the crisis, obligations that are likely to be losses for someone. We return to these questions in subsequent sections and chapters.

Retail Sales

In addition to expanding competition in electricity generation, there was the possibility of creating competitive markets for retail electricity. During the 1980s, there was a growing recognition that electricity as a commodity could be unbundled from electricity distribution services. One could envision a local distribution company that provided electricity distribution services as a monopoly, with those services being subject to regulatory oversight, and simultaneously a market in which many firms competed with one another to sell electricity, with that electricity delivered by the monopoly distribution company. In fact, Chile had put such a system in place in the early 1980s, followed by the United Kingdom and Argentina in the late 1980s. Australia and New Zealand had also unbundled electricity in this fashion,[15] making it clear that there was an opportunity for retail competition.

Such competition offered the possibility that competing retailers would provide differentiated energy services that would be attractive to consumers. Some retailers could provide "green power" to environmentally conscious consumers. Others could bundle energy efficiency measures with electricity to help consumers reduce the overall cost of obtaining energy services (for example, warmth, lighting, cooking, clothes drying, refrigeration). Some retailers could provide highly reliable electricity to the industrial or commercial customers for whom reliability was essential or interruptible service to those customers willing to accept service interruptions in exchange for a lower overall bill. Some could sell electricity at real-time prices for those customers that wished lowest average cost but did not mind price variability, and others could sell electricity at guaranteed prices, essentially selling risk management services bundled with electricity. A competitive retail market could enhance consumer options and create a more flexible system.

Thus, in the 1990s, the opportunity and the motivation arose to restructure both the generation function and the local distribution function of the California electricity industry. These factors set the stage for the debate on how to deregulate or restructure the California electricity system.

CALIFORNIA PUBLIC UTILITIES COMMISSION LEADERSHIP

It was California's regulatory agency, the CPUC, that spearheaded the move toward electricity deregulation in California. Contrary to the common view of regulatory agencies as bodies working to preserve their own power, the CPUC, or at least CPUC commissioners and staff in the early and mid-1990s, took aggressive leadership on a course of action that promised to reduce their authority over

[15]For a discussion of restructuring efforts in other countries, see Robert Thomas Crow, "Not Invented Here: What California Can Learn from Elsewhere about Restructuring Electricity Supply," (Working paper at Stanford Institute for Economic Policy Research, December 2001); available at http://siepr.stanford.edu/papers/pdf/01-10.html.

electricity markets. The deregulation that they envisioned (and at that time it was still deregulation, not simply restructuring) would rely more on competitive market forces in both wholesale and retail electricity markets and less on governmental control over electricity production and use.

Yellow Book and Blue Book

In April 1992, the CPUC initiated a review of trends in the electric industry, which initially resulted in a staff report[16] published in February 1993. This report, commonly referred to as the "Yellow Book," outlined a set of broad strategies for restructuring the electricity industry to rely more fully on market forces.

Following the Yellow Book was a CPUC Order proposing a process of restructuring California's electricity industry. This Order,[17] often referred to as the "Blue Book," issued in April 1994, envisioned competitive retail markets, in which "customers would have choice among competing generation providers,"[18] with electricity generated through a competitive wholesale market. However, the Yellow Book and subsequent restructuring Orders all maintained the utilities as monopoly providers of delivery services.

The Blue Book laid the foundation for California's subsequent electricity restructuring, proposing several fundamental changes, including replacing cost-of-service regulation with performance-based regulation, wherever regulation was needed, thereby strengthening regulated utility incentives for cost reduction. At the retail level, the Blue Book proposed to grant all purchasers of electricity voluntary and direct access to electricity suppliers in a time-phased manner. In addition, retail customers would be able to purchase electricity from the local utility. The Blue Book envisioned that both the regulated utility (operating wherever possible under performance-based regula-

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[16]California Public Utilities Commission. "California's Electric Services Industry: Perspectives on the Past, Strategies for the Future" (February 3, 1993).

[17]California Public Utilities Commission. "Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation" and "Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation," R.94-04-031/I.04-04-032.

[18]Quotation from Decision 95-12-063 (December 20, 1995). A more complete discussion of this procedural history appears in that document.

tion) and unregulated retail purchases would coexist. Electricity generation would be fundamentally deregulated. Wholesale prices would be kept "just and reasonable" by the discipline of competitive wholesale markets.

The Blue Book addressed the issue of stranded costs by proposing a financial transfer from the utility customers to the generation side of the utilities, a solution that essentially remained through the subsequent legislation. The financial transfer would be in the form of a limited-time "competition transition charge." Each retail customer in the utility's service area would be required to pay the competition transition cost for all electricity purchased. That charge could not be bypassed: even if a customer were no longer served by the utility, whatever entity sold that customer electricity would be required to collect the competition transition charge. Thus, although the total amount of money collected by the competition transition charge would depend on the total amount of electricity sold at retail, it would not depend on whether the incumbent utility or some other firm sold the electricity.

The utility would receive all money collected through the competition transition charge, allowing it to recover stranded costs. The competition charge would pay for the entire stranded costs for the given utility over a target number of years. Thus, under the Blue Book proposal, the CPUC would estimate the total of stranded costs for a given utility and the total amount of electricity that would be purchased by customers in the utility's service area over the target number of years. The estimate of total stranded costs would be divided by the estimate of future electricity sales to determine a competition transition charge (CTC) assessed in proportion to the amount of electricity sold.[19]

The total stranded costs depended on the market-determined wholesale price of electricity. If the wholesale price were very low, then the total stranded costs could be as large as the total of book values of the old plants owned by the utilities plus costs associated with the QF contracts. Conversely, if the wholesale price were very high, then the total stranded costs might be negligible. Thus, the size of the CTC would depend on the expected

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[19]The calculation would account for financial discounting of future cash flows by allowing the stranded costs to earn a financial return that would itself be included as part of the calculation of the CTC.

wholesale price and thus would need to be periodically adjusted to changing wholesale prices.

In many ways, the CTC looked like a temporary tax on electricity use that was different in each investor-owned utility's service area, depending on the magnitude of the stranded costs of that utility, and differed with the prevailing wholesale price. Unlike most taxes, the revenues would go directly to those utilities with stranded costs, not to a government entity.

If all a utility's customers remained with the utility and none switched to other suppliers, then the CTC would simply take money from the retail side of that utility and pass exactly the same amount of money to the generation side. The CTC would have no financial consequences for the utility as a whole unless it caused the retail price to change (which it would not under most regulatory regimes).

The CTC would be financially beneficial to the utility, however, if some retail customers switched electricity retailers, no longer purchasing from the incumbent utility. These customers would continue to pay the CTC, and the money so collected would be paid to the generation side of the utility. The payments to the generation side of the utility for stranded costs would be invariant to the fraction of customers who remained with the utility and the fraction that purchased from other retailers or entered direct contracts with generators.

Decision 95-05-045

Although the Blue Book laid the foundation for the restructuring, many steps were required to complete the process, each of which seemed to add more complexity to the restructured system. In May 1995, the CPUC issued a Decision that laid out two broad policy alternatives for organizing restructured wholesale markets and transmission management: a preferred (majority) policy and an alternative proposed policy.[20]

The preferred structure was a wholesale power pool, managed by an independent system operator (ISO) that would dispatch generation based on a day-ahead bidding mechanism and would arrange transmission access for generators that bid to sell electricity at prices no greater than the market-clearing price. Under this proposal, management of the grid, dispatch of generators, and wholesale trading would be integrated functions.

[20] CPUC Decision D.95-05-045.

Wholesale prices for electricity could vary sharply with supply and demand conditions, with risk for both generators and consumers. Risk management would be available through financial instruments to hedge prices. These instruments, in principle, would be immediately available to any parties that mutually agreed on them, but the CPUC was to take no responsibility for establishing markets for such hedge instruments. Energy traders and marketers, such as Enron Corporation, seemed prepared to organize such markets. The new system would allow physical, bilateral contracts that, after two years, could be used for risk management.

The alternative policy recommended consumer choice through direct access contracts. This plan would allow physical, bilateral contracts, separate from any pool bidding, to be available immediately. This alternative would allow the opportunity for competing operators of the transmission grid, with a role for the ISO only when there were transmission constraints. Under this alternative, financial instruments to hedge prices could still be available and risk management through long-term bilateral contracts would have been available to those customers who were able to negotiate such contracts.

Memo of Understanding

In September 1995, four major participants—a utility, a group of generators, and two electricity user groups[21]—presented a Memorandum of Understanding (MOU) with their joint recommendations. Although it addressed virtually all elements of the proposed restructuring, the MOU focused on market structure and stranded cost issues.[22] The proposed market structure combined features of the preferred and of the alternative proposals from May 1995. The new proposed system would be more complex and less coordinated than would either the preferred or the alternative proposals.

[21]The MOU was submitted by Southern California Edison (SCE), the California Manufacturers Association (CMA), the California Large Energy Consumers Association (CLECA), and the Independent Energy Producers (IEP).

[22]For more discussion of these changes, see William W. Hogan, "Electricity Market Restructuring: Reforms of Reforms," Harvard University, May 25, 2001.

The MOU proposed creation of a power exchange (PX), creation of an ISO, and early phase-in of direct bilateral contracts between generators and individual customers or distribution companies. Importantly, under this proposal, the ISO and the PX would be separate entities, operating independently of each other. The PX would develop a visible electricity spot market with transparent electricity prices. It would be open to all suppliers, both within and outside of California. The ISO would manage the grid.

This organization structure—with management of the grid, dispatch of generators, and wholesale trading functions kept separate—was very different from the systems that had been adopted in other countries that had restructured their markets. Normally, these functions, which are integral parts of a smoothly functioning system, would be tightly integrated into one organization. This structure created the great risk that the functions would not be well coordinated with one another.

The resulting inefficiencies in these markets would provide opportunities for energy traders, such as Enron, to operate profitably; market inefficiencies could create profit opportunities through arbitrage and through selling financial instruments for managing the increased risks. Such profit opportunities to traders would stem directly from the costs the inefficiencies would otherwise impose on generators or consumers. It was a most remarkable public policy concept: California was creating market inefficiencies to make the system profitable for arbitrageurs (more-benign explanations for this separation are difficult to conceive).

CPUC Restructuring Order of 1995: The Preferred Policy Decision

A continued set of hearings and public submissions led to a final CPUC restructuring Order,[23] issued in December 1995, often referred to as "the preferred policy decision." The Order followed the MOU recommendation to separate the ISO (to manage the grid) and the PX (to create wholesale markets). The organizational separation of the two closely connected functions, unique to California, promised to create an extremely complex and

[23] *Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.* Decision 95-12-063 (December 20, 1995) as modified by D.96-01-009 (January 10, 1996).

untested system. Like the Blue Book, the restructuring Order proposed to deal with stranded costs through a CTC designed to allow utilities to recoup all stranded costs[24] by the year 2005, a long transition period.

At the retail level, like the Blue Book, the CPUC envisioned a system in which consumers would face many options for electricity purchases. Consumers could continue to rely completely on a local distribution company to purchase and deliver electricity or could opt for direct access through bilateral contracts. Those relying on a local distribution company could agree to either pay the average cost of electricity throughout the year or pay a real-time price, a price that varied on an hour-by-hour basis with changing wholesale market conditions. Those paying a real-time price could choose hedging contracts with third parties to reduce the risk.

The CPUC restructuring Order included one provision that some have interpreted as imposing a price cap on retail electricity prices. The language of the Order is as follows:

> *One of the goals of this proceeding is to lower the price consumers pay for electricity. Recovery of transition costs frustrates this goal because it is possible that the surcharge will exceed price decreases in a given year, resulting in higher electricity-related costs for consumers. To avoid this result, we will cap transition cost recovery so that the price for electricity does not rise, on a kWh basis, above current rate levels in effect as of January 1, 1996 without adjustment for inflation.*[25]

This provision would have limited the size of the CTC, assuring that if the CTC otherwise would have increased electricity prices above the January 1966 levels, then the magnitude of the CTC would be reduced. The precise language suggests that this provision was not intended to prevent increasing wholesale costs from being passed through to retail prices but only to limit the size of the CTC. Thus, it was not strictly a cap on retail prices but a cap on the CTC.

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[24]In addition, long-term contractual obligations entered into before January 1, 1996, would be recovered over a longer time period.

[25]Decision 95-12-063 (December 20, 1995) as modified by CPUC Decision D.96-01-009, p. 139.

Electricity distribution functions would remain with the utilities and would be regulated by the CPUC. The regulated distribution costs would include a separate unavoidable component of retail rates that would have provided funds for other social goals: a Public Interest Energy Research Program (PIER) and demand-side management programs to promote energy efficiency.

This restructuring Order had set the framework in place but not the implementation details. That phase was left to a sequence of other CPUC decisions, including the 1996 Decision, commonly referred to as the "Roadmap Decision,"[26] which set in place a process for forming working groups of interested stakeholders to identify and discuss options for addressing many of the implementation issues. Thus, even after the restructuring Order and the passage of Assembly Bill 1890 (discussed in the next section), the CPUC continued to take the lead in translating the framework of the restructuring Decision and of the legislation into operational rules. Later sections of this book discuss impacts of the CPUC implementation.

Assembly Bill 1890

Although the CPUC had issued the restructuring Order, such a fundamental reform would be politically more viable if it were the product of legislation, not simply regulatory rulemaking. Soon after the CPUC restructuring Order, the state legislature embraced this role. State senator Steve Peace (D-El Cajon), a highly respected legislator, deeply knowledgeable about energy issues, provided the leadership throughout the process.

The legislative process culminated in Assembly Bill 1890 (AB 1890), formally authored by state assembly member James Brulte (R-Rancho Cucamonga). This measure was passed by the California legislature and signed into law in September 1996 by then-Governor Pete Wilson. It became effective in March 1998.

The bipartisan nature of the restructuring legislation was striking. Primary leadership for the entire legislative package came from a Democratic member of the state senate, Steve Peace; in the state assembly, a Republican, Jim Brulte (now a state senator), authored the bill. The bill passed with no dissenting votes from legislators of either party. A Republican governor, Pete Wilson,

[26]CPUC Decision D.96-03-022.

signed the bill. Moreover, the bipartisan legislation built on a very open, very public process led by the CPUC. Although, in retrospect, many commentators critical of California's restructuring have blamed Governor Wilson or Senator Peace, in reality the strengths and weaknesses of the restructuring were the result of a remarkably open and bipartisan process involving hundreds of participants from both political parties and many with no particular party affiliation.

The legislative process started from the CPUC restructuring Order of 1995 but modified several central provisions and added its own features. Most electricity, AB 1890 recognized, was generated, transmitted, and distributed by private corporations. Given this recognition, like the various CPUC Orders leading up to AB 1890, this legislation was designed not to change the dominantly private ownership of the electricity system; rather it was designed to allow competition in places where it seemed appropriate.

Like the CPUC restructuring Order, AB 1890 promised to reduce sharply the degree of vertical integration in the industry. Under AB 1890, a utility could still include the three separate functions: generation, transmission, and local distribution. Ownership of the three functions, however, would not translate to decision making coordinated among these functions. Decision making and control of its transmission function would be in the hands of the ISO, not the utility owning the transmission lines. The market structure provided incentives for local distribution decisions to be made separately from fossil fuel–fired electricity generation decisions,[27] so that a utility that both generated electricity from fossil fuel–fired plants and sold electricity at retail would operate as if two separate companies owned these two functions.

This separation of generation and local distribution was accomplished by requiring the utility to sell through the PX or the ISO all electricity it generated using fossil fuel–fired plants. The following language was included in AB 1890:

> *All "going forward costs" of fossil plant operation, including operation and maintenance, administrative and general, fuel and fuel transportation costs, shall be recovered solely*

[27]Hydroelectric generation could still be coordinated with retail sales and would thus provide the utility some opportunity of changing production with changes in load.

> *from independent Power Exchange Revenues or from contracts with the Independent System Operator.*[28]

If the investor-owned utility needed all the electricity it generated for sales to its retail customers, it was still forced to sell that electricity through the PX or ISO and purchase that same amount of electricity back. The market-clearing conditions operated independently of the identity of buyers or sellers. Thus, in selling electricity, the utility would be unable to show itself any preference as a buyer; in buying the electricity, the utility would be unable to show itself any preference as a seller.

As proposed by the CPUC restructuring Order, AB 1890 separated distribution services from retail sales of electricity. The act confirmed that distribution services would continue to be subject to CPUC regulatory authority. Distribution service would include a charge proportional to electricity use to pay for public benefit programs. These included (1) $228 million a year to pay for energy efficiency and conservation activities that had been supported by utilities, financed through their retail rates; (2) $62 million a year to create the Public Interest Energy Research program, to be managed by the California Energy Commission; and (3) $109 million a year to support emerging renewable electricity generation technologies. The total charge would be somewhat less than 3 percent of the total revenues of the investor-owned utilities and the majority had already been included in retail electricity prices prior to restructuring.

The act promised to create competition for retail electricity sales by authorizing direct transactions between electricity suppliers and end-use customers and by allowing electricity aggregators. The investor-owned utility would be the default seller of electricity. Direct access was to start simultaneously with the initiation of the PX and the ISO and was to be phased in for all customer classes by January 2002. The CPUC was directed to authorize aggregation of customer electrical load for all customer classes. Aggregation would be allowed by private-sector marketers or by cities or other public agencies, as long as individual customers could freely choose to remain with the local utility or to purchase electricity from the

[28]Although this language does not strictly require that all electricity the utility generates be sold through the PX or the CAISO, it ensures that the utility can recover none of its costs if it fails to do so. That economic incentive is as strong as a strict requirement.

aggregator. The transition period, during which the stranded costs would be recovered, was made much shorter than that proposed under the CPUC restructuring Order. This period would end no later than March 31, 2002, or whenever the stranded costs had been fully recovered,[29] whichever came first.

The cap on the CTC was transformed by AB 1890 into a retail price cap for electricity, a subtle but important change. It was required by AB 1890 that the investor-owned utilities' electricity prices for residential and small commercial customers would be reduced immediately by at least 10 percent below their June 10, 1996, levels. Since the retail electricity price and the price for distribution services were about the same, this requirement that the bundled rates be reduced by 10 percent translated to a requirement that the retail electricity price be reduced by about 20 percent. For other customers the retail prices could not increase above their June 10, 1996, levels.

In order to recover its stranded costs, each utility would propose to the CPUC a cost recovery plan that included the capped retail prices described above. Significantly, in order for the cost recovery plan to be approved, it had to meet the following criterion:

> *These rate levels for each customer class, rate schedule, contract, or tariff option shall remain in effect until the earlier of March 31, 2002, or the date on which the commission-authorized costs for utility generation-related assets and obligations have been fully recovered.*[30]

Thus, under AB 1890, recovery of stranded costs required utilities to formulate and the CPUC to approve a plan in which retail rates would remain constant until the stranded costs were fully recovered.

The system was designed with the anticipation that the CTC would lead to financial accumulations each year and that the stranded costs would be paid over a limited transition period. However, wholesale prices could not be predicted. In the legislation, there was no provision for what might happen if the wholesale price exceeded the capped retail price, perhaps by a large amount, so that a utility could not pay for the authorized stranded costs or even preserve any financial assets, as happened during the electricity crisis.

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[29]The utility would be at risk for costs not recovered by March 31, 2002.

[30]Section 10 of AB 1890.

However, AB 1890 imposed no restrictions to stop the CPUC from modifying or abandoning the stranded cost recovery plan once it had been approved, if so requested by the utility. In particular, since the CPUC could agree to reduce the amount of stranded costs to be recovered, it had the ability, if requested by a utility, to reduce authorized stranded costs to just the amount that had already been recovered. This reduction would terminate the requirement that retail rates for that utility remain at their price-capped level and would allow the CPUC to raise retail prices if needed.

High wholesale prices turned out to be a very large risk. But the risk may have been severely underestimated or completely unrecognized by many participants in the process. The utilities (or their parent corporations) could have protected themselves against high wholesale prices by entering contracts for financial hedges, designed to cover the risks of buying power from a volatile spot market while selling it at a frozen retail rate. However, although such hedge contracts were offered to utilities, they rejected these offers, apparently believing that the hedges included overestimates of the risks and thus that the prices of the hedges were too high.

In addition, an important safeguard could avoid the anomalous situation of skyrocketing wholesale prices—draining utilities of all financial assets and bringing them to the verge of bankruptcy, while retail price caps were enforced on grounds that the utility was still entitled to recover additional stranded costs. The CPUC could simply reduce allowable stranded cost recovery, terminate the transition period, and raise retail rates. However, the participants in the process probably did not recognize the risk that the CPUC would fail to act in such a way when necessary.

Like the CPUC restructuring Order, AB 1890 kept organizationally separate the management of the grid, dispatch of generators, and wholesale trading. It directed the CPUC to work with the utilities to develop a PX that was to be governed by a board that included representatives of the various stakeholder organizations in California that might be affected by operation of the PX. Otherwise, AB 1890 gave very little guidance about its functions. The only explicit language in AB 1890 was the following:

> *The Power Exchange shall provide an efficient competitive auction, open on a nondiscriminatory basis to all suppliers, that meets the loads of all exchange customers at efficient prices.*[31]

[31] This and the following quotation are from Section 10 of AB 1890.

In particular, there was no further guidance about the competitive auction, the bidding structure, or the length of the advance period during which electricity could be purchased. Such implementation issues were left to the CPUC, the PX board, and the FERC, the federal organization that ultimately had the authority to approve or reject any plans developed in California.

Under AB 1890, the transmission system would continue to be owned by investor-owned utilities but would be subject to FERC review. The CPUC was directed by AB 1890 to work with the utilities to develop an independent not-for-profit ISO to control the use of the transmission system. That ISO would also be governed by a stakeholder board including representatives of the affected various parties. This organization ultimately became the California Independent System Operator (CAISO).

The technical functions of CAISO were described in some detail by AB 1890, but it gave no guidance as to its market functions. The only language in AB 1890 hinting at the need for market functions was the following:

> *The Independent System Operator shall ensure that additional filings at the Federal Energy Regulatory Commission request confirmation of the relevant provisions of this chapter and seek the authority needed to give the Independent System Operator the ability to secure generating and transmission resources necessary to guarantee achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council.*

As with the PX, AB 1890 left implementation issues to the CPUC, the CAISO board, and the FERC.

The restructuring plan implied that the ultimate control over the design and operation of both the PX and CAISO would be with the FERC, the federal agency with regulatory power for wholesale markets for electricity,[32] rather than with the State of California. Nevertheless, the design and operating principles would be crafted in California.

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[32]The FERC has jurisdiction over sales of electricity for resale—wholesale electricity—and the state retains jurisdiction over retail sales of electricity and strictly intrastate electricity transmission.

The CPUC was directed by AB 1890 to work with the utilities to obtain authorization from the FERC for creating the CAISO and the PX. In April 1996, the three investor-owned utilities—PG&E, SCE, and SDG&E—submitted requests to the FERC[33] requesting approval of those restructuring elements subject to FERC jurisdiction. These included creation of the PX, authority to sell electricity through the PX at market rates, the creation of the CAISO, the vesting of operational control of transmission with the CAISO, approval of PX and CAISO tariffs, and the jurisdictional split, with the FERC regulating the wholesale markets and CPUC regulating the retail markets. The FERC largely approved these proposals, and in 1997 it authorized the first limited operation of the CAISO and the PX.

The set of regulatory changes, culminating in AB 1890, promised to fundamentally change the electricity system from one strictly regulated from "cradle to grave" into one in which market forces would play the primary role once each utility passed its transition period. Wholesale markets were intended to allow competition to determine supply, demand, and prices of electricity in wholesale transactions. Although analysts envisioned that most retail customers would continue obtaining their electricity bundled with distribution services sold by regulated utilities, the seeds for a competitive retail market were planted.

The set of changes thus was designed to transform the system while grappling with transition problems of moving from a system of vertically integrated regulated monopolies to a competitive one. This was to be a fundamental and radical transformation of the system that required leaders to face a series of challenges. In facing these challenges, new problems were created, as discussed in subsequent sections.

The framework for the fundamental transformation was thus set by AB 1890. However, it was simply a framework, not a set of detailed designs for system implementation. The structure of the PX and CAISO, as well as the markets they were to operate, was left to stakeholder committees and the CUPC, with the FERC to approve or disapprove the designs. Careful delineation of the

[33]FERC Docket Nos. ER96-1663-000 and EC96-19-000. The applications were filed after the CPUC restructuring Order but before passage of AB 1890. These applications were approved only after AB 1890 was signed into law. FERC took due note of the passage of AB 1890 during its proceedings.

jurisdictional split between federal and state regulators was left to the various parties to work out.

The parties were left by AB 1890 with many complex and potentially divisive issues to work out and very little time to accomplish that end. It came into effect only eighteen months after it was signed. With such a tight implementation schedule, the original applications to the FERC were filed while the California legislature was still considering AB 1890. Once the FERC approved the applications, the large size and diversity of the part-time stakeholder boards made it difficult, if not impossible, to seriously rethink or revise the original structure. Working out jurisdictional conflicts within the short time frame was close to hopeless.

The following examines these various system components in depth.

WHOLESALE MARKETS UNDER THE RESTRUCTURED SYSTEM

The restructured system required several markets and market institutions for buying and selling electricity at the wholesale level. Much work was needed to implement this complex system. Because the system had been newly designed, it was reasonable to expect that some elements would be flawed and thus require modification. In addition, because the particular market institutions and the relationship between these institutions could not initially be completely understood, significant risks were associated with these wholesale markets.

The California Power Exchange (PX)

The investor-owned utilities and the CPUC developed, and the FERC approved, plans for the PX and for the wholesale markets that the PX would manage. The PX organized a set of competitive auctions, open on a nondiscriminatory basis to all suppliers.[34] The PX initially established one-day-ahead and day-of wholesale markets for electricity. Only much later did it establish markets that allowed contractual agreements extending longer than one day in advance.

[34]The three large investor-owned utilities were required to sell through the PX. For all entities other than the three large investor-owned utilities, use of the PX was optional.

For both the one-day-ahead and day-of wholesale markets, the PX accepted bids to sell electricity hour by hour and bids to purchase electricity hour by hour. Prices for each hour were determined on a market-clearing basis, with all buyers for a given hour paying the same market-clearing price and all sellers receiving the same market-clearing price.

In this market, each generator would bid to sell its available supplies at some offer price,[35] and each utility (or other load-serving entity) would bid to purchase electricity at some offer price.[36] Once the market-clearing price was determined, all bids to sell with offer prices lower than or equal to the market-clearing price and all bids to purchase with offer prices greater than or equal to the market-clearing price would be accepted; all sales bids with higher offer prices or purchase bids with lower offer prices would be rejected. The market-clearing price was the lowest price that would provide enough electricity from accepted sales bids to satisfy all the accepted purchase bids.

This market-clearing price setting can also be envisioned in an equivalent way. The sales bids would be ranked from lowest offer price to highest offer price—that is, in their merit order. The purchase bids would be ranked from their highest offer price to the lowest offer price, in their merit order. Equivalently, for purchasers that simply offered to buy a fixed quantity, the quantities would just be added up. At some price, the total of sales bids up to that point in their merit order would be equal to the total of purchase bids down to that point in their merit order. That price would be the market-clearing price.

All sellers would receive the market-clearing price for their electricity, even if they bid less than that price; all buyers would pay the market-clearing price, even if they bid more than that price. This one-price market system was fashioned after typical commodity markets, in the recognition that bulk power was a nondifferentiated commodity.

[35]Most of these offer prices would be determined by the owner of the generator itself, although some generators, designated as "must run," would be required to set offer prices equal to zero.

[36]In practice, utilities could simply state a quantity of electricity they wished to purchase. That would be equivalent to a purchase bid at some very high price, a price ensured to be higher than the market-clearing price.

The theory behind such a bidding system is that all bids to sell electricity would be priced at the marginal cost of that electricity.[37] This theory was based on the observation that a supplier, bidding its total quantity at a single price in a competitive market, could make the most profit by bidding at a price equal to its marginal cost for producing that electricity. Increasing the sales bid above marginal cost would not increase the payment the supplier would receive from that sale—since all payments would be equal to the market-clearing price—but could cause the firm to lose a profitable sale. Bidding at a lower price than marginal cost would also not change the revenues if the bid were lower than the market-clearing price. However, such a bid could result in the firm selling electricity at a price lower than its marginal cost and thus losing money. Therefore, for a firm operating competitively, bidding a price equal to its marginal cost would lead to the greatest profit. For such firms bidding in a competitive market to sell electricity, there was a strong incentive to offer to sell at the marginal generation cost.[38]

This system was designed to simulate a perfectly competitive commodity market in which a price would be known and each firm would be able to sell its commodity at that price. It would choose to do so if its marginal cost (including any opportunity cost) were lower than its price. In theory, such a competitive market would be desirable for the wholesale electricity markets and would result in the lowest total cost to generate a given amount of electricity.

There were several alternatives to such an auction system. One alternative, in principle, would have been to set up a normal commodities futures market. People would enter bids to

[37]The theory was also based on the symmetric assumption that all bids to purchase electricity would be priced at just the marginal value to the user. However, the regulatory system for retail sales of electricity ensured that assumption was never valid.

[38]The theory would be precisely correct only if there were a continuum of bid prices so that if the highest successful bidder were to increase its bid price at all, it would then become higher than the next more expensive bid. If, however, there was any gap between the highest successful bid and the next more expensive bid, the firm could make more profit by bidding a tiny amount below the next bidder, not by bidding at marginal cost. But if a firm did not know exactly the prices others were planning on bidding, such a strategy would not be possible. In that case there would still be an incentive to bid just a bit more than the marginal cost.

buy and sell, prices would adjust, and ultimately equilibrium would be reached. However, such an adjustment process would take time, and electricity markets had to adjust on a much faster time scale than would normal commodity markets. Markets would need to clear on an hourly basis; there were twenty-four separate markets to clear for each day. Moreover, all adjustments would have to be completed, starting at most one day before the day of electricity delivery. Thus, prices would need to adjust very quickly. The only viable method was a computer-based system that calculated market-clearing prices and matched buyers and sellers of electricity for each hour, which would simulate the workings of a competitive commodities market without actually being one. The single price auction was designed to serve that function.

A second alternative would be to design the system to pay bidders just what they bid, rather than to pay them the market-clearing price. Under such an alternative, just as under the market-clearing system, bids would be arrayed in merit order until sufficient quantities were available to satisfy the bids to purchase electricity. This point in the merit order would determine a cut-off price. Any bids higher than the cut-off price would be disregarded, just as under the market-clearing system, whereas any bids lower would be accepted. Bidders would be paid the price they bid rather than the market-clearing price. The total cost of all purchases would be averaged, and the buyers would each pay the average bid price.

Many have argued that a system of paying on an as-bid basis, rather than on a market-clearing basis, would result in smaller total payments by the buyers of electricity. After all, those bidding to sell at prices below the cut-off price would not receive the cut-off price but would receive only their bid prices. The fallacy of that reasoning is that it implicitly assumes that the sellers of electricity would offer the same bids under an as-bid system as they would under a market-clearing system. In fact, the bidding strategies would be very different under the two systems.

Under an as-bid system, each firm makes the most profit by guessing the cut-off price and bidding at or just below that price, as long as the cut-off price is at least as high as its marginal cost. Thus, even in a competitive market, suppliers would *not* bid at their marginal costs.

If all firms could guess the cut-off price perfectly, each firm whose marginal cost was no larger than the cut-off would bid the cut-off price and each would be paid the cut-off price.[39] The cut-off price would be the same as the market-clearing price. Thus if each firm could guess the cut-off price perfectly, an as-bid system would result in the same payments as would a market-clearing system. The advantage often postulated for such a system would disappear under the best circumstance: perfect guessing.

Although each firm would learn much from observing the results of the hourly bids, twenty-four a day, there would undoubtedly be mistakes, and to compensate, firms would bid somewhat below their estimate of the cut-off price. Some lower-cost firms would guess incorrectly and bid above the cut-off price, thereby leading to increases in the cut-off price. Thus, some higher-cost firms would generate electricity and some lower-cost firms would remain idle. The total cost of generating the given quantity of electricity would therefore be increased above the cost in a market-clearing system.

The net result would be some variability in the prices paid for electricity at any hour, with some prices higher than what would have been the market-clearing price and some possibly lower. Whether such a system would increase or decrease the total payments for obtaining a given quantity of electricity would depend on the precise bidding strategies of the various market participants. However, an as-bid system could be expected to increase the total cost of generating electricity and would therefore be less efficient than a one-price market-clearing system.[40]

There was another difficulty with the auction system, arising because the system was based on hour-by-hour bidding and hour-by-hour market clearing. Some generating plants, typically operating as base-load plants, have very long and very costly periods for ramping up from no production to full capacity. These plants might be profitable to operate if they received at least a particular price, say, $30/MWh, for a large fraction of the day or for all of the peak period of a day. However, if they were operating only a few hours, even at a higher price, say, $40/MWh, they might not be profitable to operate, since the fixed costs of ramping up could be greater than the profit earned during those more limited hours. For such plants, their offer price at any hour must depend on whether they would be generating electricity at the other hours of the day.

[39]No firm would bid lower than its marginal cost, the cut-off price, which would be as high as the market-clearing price.

[40]The optimal bidding system in such markets remains a controversial issue, and there is much economic literature on the question. England pays on an as-bid system.

For such plants, bidding based on unit commitments—commitments of the unit to operate for long blocks of time—would be more appropriate and might result in lower bid prices. This issue was most likely to be relevant when market-clearing prices were near the costs of base-load plants and least likely to be relevant when market-clearing prices were near the costs of peaking units. Thus, this issue threatened to increase market-clearing prices during periods of relatively low prices but was likely to have little or no impact during periods of relatively high prices.

Given the alternative auction systems that could have been designed, the one chosen for the PX was reasonable, although not perfect. Since the system was necessarily untested, it could have been flawed in unpredictable ways. In fact, given the potential for strategic bidding or other means of exercising market power, any system designed for the PX could have been flawed. Any system that gave generators an incentive and ability to significantly increase the market-clearing price or the cut-off bid price had the potential to drive prices well above competitive levels. Any system that excluded bidding for long-term commitments could be awkward for some baseload generators. The possibility of such flaws was a major risk associated with restructuring the California electricity markets, indicating the importance of monitoring the system and adjusting when problems were identified.

The California Independent System Operator (CAISO)

The system was even more complicated than has been suggested in the previous paragraphs, primarily because of the special characteristics of electricity:

- The amount of electricity used varies sharply over the course of the day as well as over the course of the year.
- The amount of electricity used at any instant cannot be perfectly predicted.
- The amount of electricity used cannot be controlled by CAISO or the utility. When an appliance, machine, computer, or light goes on, it draws electricity from the system. This is true even if insufficient electricity is available.
- Electricity cannot be stored. It is used at the instant it is generated. Therefore, electricity generation must be balanced against electricity use at every instant of time.

- When loads and electricity generation are spatially separated, electricity must be transmitted from the point of generation to the point of use. But transmission capacity is limited. Attempts to transmit too much electricity over a transmission path will result in the line shutting down to protect from permanent damage.
- If too little or too much electricity is generated in any location, relative to the use of electricity, the entire grid could become unstable and crash.

These characteristics necessitated the creation of an organization responsible for managing the transmission grid, providing resources to ensure safe operations of the grid, and maintaining sufficient quantities of electricity at all times. This organization was to be the California Independent System Operator.

Once markets cleared in the PX for a given hour, utilities and generators would have commitments to receive and to supply electricity. All utilities, in principle, would have balanced loads and resources; that is, the total load they expected would be equal to the electricity-generation resources committed.

However, those commitments could not ensure that the system would operate correctly. First, although each utility might have commitments to supply the total amount of electricity it needed, the individual commitments could well exceed the limitations of the transmission system to move electricity from points of generation to points of load. Some organization was needed to manage this transmission system. Second, although all loads and resources were to be balanced, in practice the participants in the market, even early in the day of actual delivery, could not perfectly project the electricity needs, if for no other reason, because the weather could not be predicted perfectly.

Figure 2.2, copied from the CAISO web site (http://www.caiso.com/SystemStatus.html), illustrates the issues of forecasting electricity usage. This graph shows actual and projected loads on a ten-minute-at-a-time basis on one normal Sunday in November 2001. The top line of the graph shows the available resources for each ten-minute interval during the day in green. For this day, the available generating resources are in the range of 30,000–32,000 MW.

The lower three curves show two projections of electricity consumption and actual consumption. The blue line shows the forecast

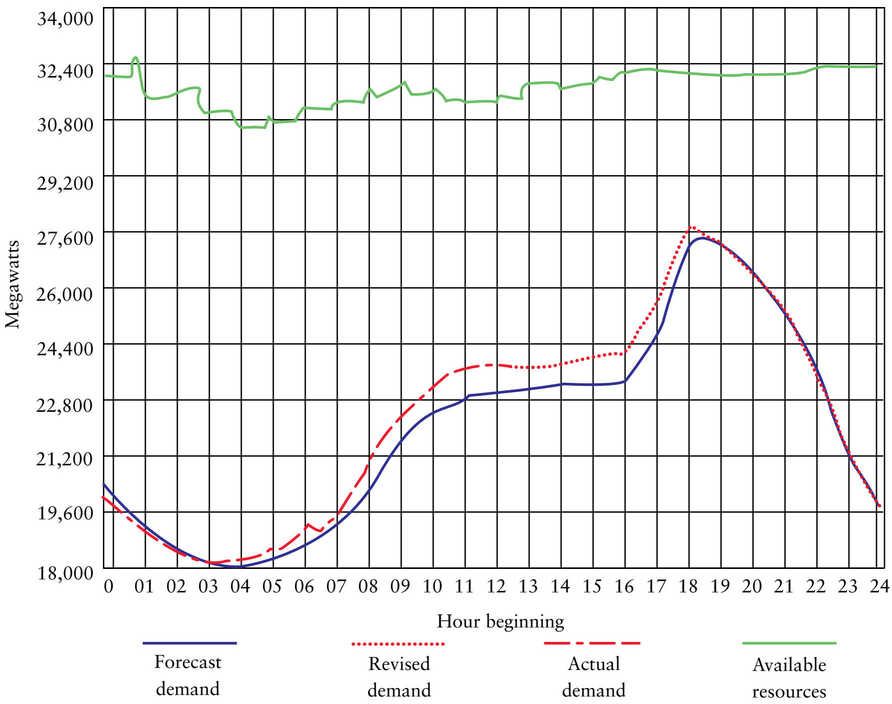

FIGURE 2.2: Example of CAISO Load Forecast, Actual Load, and Available Generating Resources: Sunday, November 4, 2001

electricity use completed once the previous day's electricity markets had closed. Note that, unlike the quantity of available resources, the forecast of actual load includes substantial variation over the course of the day. The broken red line shows the actual system demand (plus a 3 percent reserve margin) from midnight until noon, when the graph was generated. The dotted red line shows the "revised demand forecast," the forecast of the system demand expected for the remainder of the day. This forecast is revised by CAISO on an hourly basis to reflect changing conditions.

In comparing the actual load with the forecast, one can see that although actual demand closely follows the forecast, at some moments demand is as much as 800 MW greater than the forecast. Even small variations of this type require responses from the system operator. Because the actual use of electricity exceeds the forecast, and because the forecast formed the basis for procurement of electricity, the system operator would be required to dispatch additional electricity on very short notice. The requirements to modify generation on short notice are even greater than suggested by Figure 2.2, since the graph illustrates only the variability across the entire control area. However, additional variability between Northern California and Southern California could require generation to be decreased at one location and increased at another.

Third, safe operation of the electricity system requires that operating reserves of generation capacity be made available to compensate for unexpected changes: a generator suddenly fails, a transmission line or transformer is damaged, electricity usage suddenly increases. Some organization was needed to obtain contractual assurance that electric generators could be brought on-line very quickly if needed. This function will be described more fully in the section "Ancillary Services."

CAISO Real-Time Markets

To perform these functions, the CAISO collected the schedules of electricity to be generated and of the electricity loads to be served by the investor-owned utilities, the municipal utilities, and a host of other entities on an hour-by-hour basis. Forty-some "scheduling coordinators" reported their schedules to CAISO; CAISO integrated these schedules and ensured that they did not collectively overload any parts of the transmission grid or were in any other ways not feasible.

Each scheduling coordinator was required to submit a balanced schedule in which the total loads and resources were equal to one another.[41] That is, the total projected use of electricity at each hour and the total generating resources to provide that electricity were required to be equal for each submission by every scheduling coordinator. Thus, in theory, the sum total of loads and resources would be balanced for the system, provided that individually submitted schedules did not create too much congestion on the transmission system, in which case CAISO was charged with rescheduling to keep the overall system operating appropriately.

However, as noted above, the participants in the market could not perfectly project the electricity needs, and the loads and resources could become unbalanced. To correct such imbalances, the CAISO was to run a real-time energy imbalance market, buying and selling electricity after the PX day-of market had closed. CAISO, therefore,

[41] More precisely, the sum of all loads and the sum of all generation submitted by a scheduling coordinator must be within 2 MW of each other.

had to monitor closely the actual use of electricity, comparing that to the quantities submitted by the scheduling coordinators, and had to use that evolving information to guide its purchases and sales of electricity in the real-time imbalance market. Purchases and sales could occur up to a few minutes before the electricity would be needed.

Deviations between predicted and actual supplies and demand would be corrected on this imbalance market. System designers expected these differences to be small, requiring only small purchases or sales. But the CAISO did not institute penalties for imbalances, even for extreme imbalances, although such penalties would be needed to ensure that scheduling coordinators did not deliberately misschedule whenever it was economically advantageous to do so. Thus, it should not have been a surprise that imbalances turned out to be large fractions of scheduled power.

The entity with the detailed minute-by-minute information was CAISO. Moreover, it was responsible for purchasing and selling electricity on behalf of the scheduling coordinators. Because it was engaged in these balancing transactions, its decision rules were central to the real-time market for electricity. These decision rules were encoded into CAISO software and were made publicly available as part of the published CAISO tariff. Thus, the market participants were fully aware of the rules and the operations of the market and could make their bidding decisions with full knowledge of how the markets would operate.

One rule was that the CAISO would acquire sufficient electricity to meet the loads it predicted. These predicted loads would not depend on the prices CAISO paid for the electricity and, in particular, CAISO would not reduce its electricity acquisitions even if the acquisition prices became very high, which allowed prices for electricity purchases on the imbalance market to become very high without the discipline of short-run demand reductions. A second rule was that CAISO would reject bids above some wholesale price cap level (to be discussed at a later point), which was, during different times, \$250/MWh, \$500/MWh, or \$750/MWh. This rule put limits on wholesale prices in the imbalance market, but they were high limits.

CAISO Ancillary Services Markets

In order to manage the system, given the special characteristics of electricity, CAISO needed to obtain agreements with generators to provide generation reserves that could be called on at short notice to increase or decrease the total generation of electricity. These reserves, as well as additional resources or loads that can be controlled to keep the system stable, are referred to as "ancillary services."

Ancillary services (see box) include units whose output can be adjusted continuously and remotely by CAISO, units that can be brought up to full load within ten minutes, loads that can be reduced within ten minutes, and generation and loads available within one hour. Because CAISO balances the scheduled load and the actual load every ten minutes and adjusts its forecasts on an hourly basis, it acquires a portfolio of reserves that it can dispatch with different amounts of advance notice.

Sellers of ancillary services are paid by CAISO to make their generating units available should they be needed. If it turns out that these units are needed, the sellers are paid for the electricity generated.[42]

Every load-serving entity (typically an electric utility) is responsible for its proportional share of ancillary services. Each scheduling coordinator can choose whether to provide its share of ancillary services or to have these services purchased on its behalf by CAISO.

For those ancillary services not self-supplied by the scheduling coordinator, CAISO manages a single-price bidding system that operates in day-ahead and hour-ahead periods. The CAISO can obtain additional ancillary services through supplemental bids offered during the hour the reserves are needed.

Every generator selling ancillary services, by necessity, could generate electricity (although the converse is not true). Thus, the generation resources being bid into the ancillary services markets could have been used as resources to generate electricity, and many of the resources that were being bid into the real-time electricity market could be used as ancillary services. A single resource owner could submit bids to the CAISO to generate electricity and submit bids for each one of the ancillary services. However, the single resource could not be used simultaneously for the various purposes.

Thus, an additional complication for the CAISO was for its software to choose which bid to accept from a single generating resource, if any of its bids were to be accepted.

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[42]Initially, this system was set up so that these units would be paid for the electricity plus paid for the ancillary services. However the FERC later required the CAISO to change the rules so that generators would be paid for either generating electricity or providing ancillary services, but not both.

Types of Ancillary Services:

Spinning reserve—Spare synchronized capacity that can be loaded to a specified amount within ten minutes and be sustained for at least two hours.

Non-Spinning Reserve (Generation)—Off-line capacity that is capable of starting up and ramping to the desired level within ten minutes and can be sustained for at least two hours.

Non-Spinning Reserve (Dispatchable Load)—Dispatchable loads that can be reduced within ten minutes and can sustain interruption for at least two hours.

Replacement Reserve (Generation)—Generation capacity secured in the day-ahead or hour-ahead market to cover forecast inaccuracies or system contingencies. Units are capable of starting and ramping up to the desired ouput within an hour.

Replacement Reserve (Dispatchable Load)—Dispatchable loads that can be reduced to a specified amount within an hour.

Regulation—Units controllable by ISO whose output is adjusted continuously by ISO to balance demand. Must be able to control with ISO AGC Package.

Black Start—Units that can start without an external source of power. Not currently running in auction via SI scheduling system.

Voltage Control—Units that contribute reactive support into the system to maintain system stability. Not currently running in auction via SI scheduling system.

SOURCE: "Scheduling and Bidding Guidelines. Market Operations," California ISO

Relationship of PX Market Clearing and CAISO Market Clearing

The electricity to be bought and sold on the CAISO real-time market was exactly the same electricity that could have been bought and sold under the PX in the day-ahead or day-of market. Thus, the PX markets and the CAISO imbalance market were simply alternative venues under which the same electricity purchases and sales could be arranged. Buyers could choose the markets where they wanted to make their purchase commitments just as sellers could choose the markets where they wanted to sell their electricity. The commitments to purchase and to sell through the PX were simply made up to a day earlier than the commitments to purchase and to sell through the PX real-time imbalance market. The PX and CAISO markets, therefore, were tightly linked to one another.

Moreover, the market participants understood that linkage. Therefore, prices on the two markets could be expected to be statistically very similar so long as firms were allowed to substitute freely between them. If generators expected the price on the real-time market to be higher than the price on the PX, they would avoid bidding into the PX and would choose to sell on the higher-priced real-time market. This would drive the prices up on the PX and down on the real-time market until the expected price difference disappeared. Similarly, if generators expected the imbalance market price to be lower, they would try to sell all of their electricity through the PX, thus lowering the PX price and raising the real-time price until the expected price difference disappeared. Incentives were equivalent for wholesale purchasers of electricity, who could schedule their purchases on the day-ahead or day-of PX markets or acquire their electricity through the CAISO real-time imbalance market. This process of adjusting on which market to bid would normally increase or decrease prices on the two markets until market participants expected the two prices would equate.

However, the rules established for the scheduling coordinators to some extent limited this free substitution between the markets and had the potential to increase market inefficiencies. In principle, the requirement that all submitted schedules be balanced might imply that firms would not be allowed to substitute completely between these two markets and that there would be relatively little electricity transacted on the imbalance market, except during those times when demand was unexpectedly large or small.

In practice, if utilities expected prices to be significantly lower on the real-time market, they would have a strong incentive to submit an unbalanced schedule, with scheduled resources well short of projected loads. However, the rules did not permit anyone to submit unbalanced schedules. This conflict between the incentives for unbalanced schedules and the requirement that the submitted schedules be balanced could easily be resolved through systematically biasing the projections of loads. A utility that systematically and purposely underestimated loads could submit a schedule that would in fact be unbalanced but that appeared on paper to be balanced, thus meeting the letter, but not the spirit, of the requirement. Thus, the requirement that schedules be balanced did not substantially limit the ability of the electricity buyers and sellers to substitute between the two markets and did not lead to systematic price differentials between the PX markets and the CAISO real-time market.

In particular, the ability of the utilities to systematically underestimate their loads implied that wholesale price caps in the CAISO real-time markets would translate to market prices in the PX limited by the same price caps, even though there were no formal price caps in the PX markets. If the wholesale market-clearing price would naturally exceed the CAISO price cap, utilities would under-schedule on the PX until the PX price was driven down to the CAISO price cap. The remaining transactions would occur on the CAISO real-time market, which was controlled by the price cap. Thus, the CAISO price cap would limit all PX prices.

When the price caps were controlling prices, there could be a shortage of electricity: the utilities might not be able to satisfy all remaining electricity demands through purchases on the CAISO. Normally, one would expect that the prospect of a shortage in the real-time market would cause utilities to bid above the price cap in the PX so that they would not be the ones to experience the consequences of the shortage. That is, if there were a \$250/MWh real-time price control that was leading to shortages, one would expect a utility to be willing to bid \$260/MWh or more in the PX to acquire all the electricity it needed. Normally, that would ensure that the utility's customers would not face required load shedding or blackouts (see discussion about energy emergencies in Chapter 4). However, California had established rules so that during a shortage all utilities would equally share the consequences, whether they had purchased enough electricity on the PX to cover their needs or not. Under these rules, bidding $260/MWh would cost the utility more but would provide no additional protection. Therefore, there was no incentive for any utilities to bid above the price cap on the PX, and the CAISO real-time price caps effectively controlled the maximum prices on the PX.[43]

When a utility consistently under-projected its loads, utility personnel would expect the schedule to be unbalanced and CAISO personnel would expect so as well. However, the submitted schedule would meet the formal requirement to be balanced. One unfortunate result was that the imbalance market would involve a much larger transaction volume than ever intended. In addition, operating rules that kept the CAISO separate from the PX restricted CAISO personnel from working to clear the imbalance market earlier than the hour during which the electricity was needed. This set of rules made the imbalance market unnecessarily chaotic and further created the inefficiencies that justified the role of energy traders.[44]

There is a second implication of allowing sellers and buyers to substitute between markets for their transactions. Not only would the market-clearing price be statistically the same under the PX

[43]It should be noted that had the situation been reversed—if price caps existed on the PX but not on the CAISO real-time market—the PX price caps would not have limited the wholesale price level. In the presence of such PX price caps, if market-clearing prices would normally exceed the price cap, utilities would try to schedule all of their loads on the PX, but the sellers would offer to sell only on the CAISO real-time market. There would be a shortage in the PX market: demand would exceed supply at the controlled price. But that shortage would have no particular relevance to the electricity system since no electricity was dispatched through the PX. The utilities, unable to purchase enough electricity on the PX, would need to purchase it on the CAISO real-time market; their electricity demands would simply become demands for purchases on the real-time market. With no price caps on the real-time market, prices would rise to market-clearing levels. The fundamental difference from the actual rules is not that the CAISO real-time market clears later than the PX markets, as some commentators have suggested, but that the electricity is dispatched through the CAISO and shortages there would have a real significance. Electricity was not dispatched through the PX and shortages there would create difficulties for the market managers and the participants but would have little or no real significance for the electricity system.

[44]It is not clear whether energy traders understood that the requirement for balanced loads would create further market opportunities for them or whether that was simply lucky from their perspective and unlucky from California's perspective. But it did predictably create many arbitrage activities.

and real-time markets; in addition, the price would depend on the total electricity supply and total electricity demand for each particular hour and not on the fractions of the electricity sold on the two markets. Therefore, for discussions of the overall wholesale price level, it will not be important to distinguish between sales on the PX market and sales on the CAISO real-time market.[45]

Bidding Strategies for Electricity Generators

As discussed above, design of the markets operated by the PX and the CAISO was based on the theory that all bids to sell electricity or ancillary services would be priced at just the marginal cost. However, there are reasons that theory might be invalid. First, there was the possibility of exercising market power, and second, optimal bidding in competitive markets might require bidding above the marginal cost. Either reason would lead to bids that exceed the marginal cost of generating electricity or providing ancillary services.

The theory that a firm always bids to provide electricity or ancillary services at marginal cost depends on the assumption that a generator or marketer bids competitively, that is, bids taking into account the expected prices in the market and not attempting to change them. However, there would be an incentive for a firm to attempt to increase prices if it could do so and still sell its electricity. A generator could bid a high price, expecting it to be rejected. Rejection of the bid would move the market-clearing price up the merit order and might lead to a price increase. However, since the bid would be rejected, the generator's electricity would not be sold and that generating unit would earn less profit, not more.

If the generator had a portfolio of units, however, the high price, sure-to-be-rejected offer on one unit could sacrifice profits for that unit while potentially increasing prices on all other units. If the gain on the other units were great enough, then bidding a high price on only one unit could be a profitable strategy. If that were the case, the firm would have an incentive to bid above the marginal cost to increase the market-clearing or cut-off price.

If some bidding strategies were allowed, a generator would not even need a portfolio of generating units. If it were allowed to offer different bids for various portions of the capacity of a

[45]However, many issues of short-term risk bearing and market inefficiencies will still depend on understanding the differences between these two markets.

single unit, it would not need multiple units. A hypothetical example of the incentive to increase bids above marginal cost can be illustrated. Assume that a firm has 1,000 MW to offer for sale in a given hour, has a marginal cost of $35/MWh, and that the market-clearing price would be $40/MWh if the firm bid all 1,000 MW at its marginal cost. The firm would earn $5,000 during that hour.[46] The firm might choose as a bidding strategy to offer to sell only 900 MW during that hour at a price of $35/MWh and the last 100 MW at a price of $70/MWh. That bidding strategy would change the merit order; assume that the market-clearing price would rise to $41/MWh, a 2.5 percent increase. That firm would forgo the opportunity to sell the last 100 MW but would sell the first 900 MW at an increased price, obtaining a profit of $6/MWh on 900 MW sold for an hour. This profit would now be $5,400, an increase of $400. That firm would have a financial incentive to follow such a bidding strategy, increasing the bid price for some fraction of its capacity above its marginal cost, even though it would not be able to sell the last 10 percent of its potential output.[47]

The bidding strategy described above might be profitable for many firms, but whether it would be profitable was not known at the time of the restructuring and is not yet known with certainty even several years later. Putting the example in a California context, the generator had a capacity equal to only 2.5 percent of the total generation capacity,[48] a very small market share. Its bidding strategy reduced the amount of electricity offered for sale at market-clearing prices by 0.25 percent of the total and, as a result, increased the market-clearing price by 2.5 percent. Thus, the example assumes that the percentage increase in price is equal to ten times the percentage reduction in quantity offered for sale. This assumption might have been realistic when the California electricity system was operating near full capacity, the California retail price

[46]The firm would be selling 1,000 MW for one hour; the market-clearing price would exceed the marginal cost by $5/MWh.

[47]This example depends on the firm bidding high enough so that the high price bid is rejected. If the firm simply offers an increased bid but is able to sell its electricity on this market, it cannot increase its profit. In addition, this example assumes that the firm does not expect it might have to repay any overcharges it creates by utilizing this strategy.

[48]For this example, it will be assumed that at the original market-clearing 40,000 MW would be utilized.

caps were limiting retail responses, and there were few opportunities for importing additional electricity into California. In this example, under those assumptions, a firm having only a very small market share had the incentive to bid so as to raise the market-clearing price by 2.5 percent.

Under these assumptions, all firms with market shares of 2.5 percent or greater and marginal costs of $35/MWh or greater would have the same incentive as shown above, if such bidding strategies were allowable. If, for example, firms collectively having 50 percent of the market share would independently all follow the same strategy, then the market-clearing price could increase by around 50 percent, or to $60, in response to the 5 percent reduction in total quantity sold. At this higher wholesale price, a 2.5 percent market share firm would no longer have an incentive to follow this strategy, but a firm having 5 percent or more market share would.[49]

If any of the basic assumptions are relaxed (full capacity, retail price caps, little opportunity to import additional electricity, multiple bid levels allowed from one unit), then there would not be an incentive, or the incentive would be greatly reduced. The relaxation of any assumption (other than the fourth one) would reduce the impact of supply reductions on price. In that case, the incentive to bid above marginal cost would be sharply reduced and would be relevant only for firms with significantly greater market share.

For example, assume that under the same assumptions described above, the percentage increase in price would be twice as great as the percentage decrease in supply. If the firm offered to sell only 900 MW at marginal cost and the last 100 MW at a price above market-clearing , then the market-clearing price would rise to $40.20/MWh, a 0.5 percent increase. That firm would obtain a profit of $5.20/MWh on 900 MW sold for an hour: a profit of $4,680 and a decrease of

[49]With a market-clearing price of $60/MWh, the firm having only 1,000 MW of capacity would no longer have an incentive to bid high prices for 10 percent of its capacity. However, a firm with 2,000 MW, a 5 percent market share, would have such an incentive. That firm, if it bid all 2,000 MW at cost would obtain a profit of $50,000 for the hour. The firm reducing its sales to 1,800 MW could increase market-clearing price 5 percent to $63/MWh. This would increase the difference between price and marginal cost to $28/MWh and would increase profit to $50,400. Thus the incentive to offer a very high bid on a small fraction of the output would remain for firms with a 5 percent market share even though it would disappear for firms with only a 2.5 percent market share.

$320. That firm would not have a financial incentive to follow such a bidding strategy. Similarly, a 5 percent market share firm would not find such a strategy profitable.[50]

If the firm were restricted in its bidding so that a segmented bid would require 50 percent of its output to be offered at the higher price, the incentive would also disappear. Assume again that the percentage increase in price would be ten times greater than the percentage decrease in supply. If the firm offered to sell only 500 MW at marginal cost and the last 500 MW at a price above market clearing, then the market-clearing price would rise to $45/MWh, a 12.5 percent increase. That firm would sell the first 500 MW, obtaining a profit of $10/MWh on 500 MW sold for an hour. This profit would now be $5,000, neither increasing nor decreasing. That firm would not have a financial incentive to follow such a bidding strategy.

Thus, exercise of market power would be less likely if the system were well below capacity or when additional electricity could easily be imported into California. In addition, if demand for electricity were more responsive to price changes, then supply reductions would have only smaller impacts on prices and the incentives to bid above marginal cost would be much smaller than suggested in this example.

With California's restructuring there was a significant risk that firms could and would exercise market power in the manner described above or by following other bidding strategies. This created risks that the wholesale market prices would be too high. Moreover, the risk that firms might exercise market power did not depend on the particular auction system. The potential would have been as great for an as-bid auction system as it was for a market-clearing system. Thus, this was a risk of moving to almost any deregulated wholesale market.

In addition to the risk that generators could exercise market power was the possibility that competitive reasons would cause generators to offer bids to sell electricity or ancillary services at prices greater than marginal generation costs. These competitive

[50] If the firm offered to sell 1,800 MW at marginal cost and the last 200 MW at a price above market clearing, then the market-clearing price would rise to $40.40/MWh, a 1 percent increase. That firm would obtain a profit of $5.40/MWh on 1,800 MW sold for an hour, earning $9,720 rather than the $10,000 it could earn by bidding at marginal cost.

reasons would likewise lead to market-clearing prices higher than would be the case in their absence.

As indicated above, generators selling ancillary services could generate electricity and, for many firms, generators selling electricity could have used the capacity to sell ancillary services. Although a single resource owner could submit bids to CAISO to generate electricity and bids for each one of the ancillary services, the single resource could not be used simultaneously for the various purposes. The generator had to decide what prices to place on each of its bids, given its understanding about how the CAISO software would select among the various bids from a single generator. The generator bidding on the PX had to decide what prices to bid given its belief about the CAISO prices for real-time imbalance electricity and for ancillary services, markets into which it could bid, but only if it did not commit its electricity on the PX.

Given multiple opportunities, a firm bidding competitively—that is, not expecting to change any market-clearing prices—would not obtain the greatest profit by bidding at just its marginal cost. Such a profit-maximizing firm, when bidding to sell electricity on either the PX or CAISO markets, had a financial incentive to take into account its opportunity cost[51] of not being able to sell the capacity as ancillary services, which would lead to increases in the offer price at which it would bid to sell electricity. Similar considerations would hold for bidding into the ancillary services markets. A profit-maximizing firm, when bidding to sell its capacity as nonspinning reserve, must take into account its opportunity cost of not being able to sell the capacity as another ancillary service, such as regulation. Thus, the bid to sell as nonspinning reserve would be increased above marginal cost, adding in opportunity cost.

In general, optimal bidding will require the generator to estimate an opportunity cost based on the most profitable of the alternative uses for the generation capacity. This opportunity cost must be added to the marginal cost in order to determine optimal bids if the firm is operating competitively. Thus, firms bidding competitively can be expected to bid generation capacity at prices that are greater than marginal costs.

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[51]The opportunity cost is the cost of having to forgo one opportunity to pursue another opportunity. Although opportunity cost is not easily measurable, it is a real economic cost often important for decision making.

The magnitude of the opportunity cost will depend on the expected market-clearing price for electricity or for ancillary services in the most profitable of the alternative uses. However, the generator does not typically know these market-clearing prices at the time it submits its bid and must guess them, instead. Thus, for a firm bidding competitively, the bid prices for each possible use of the generation capacity must take into account the bidder's best estimates of the market-clearing prices for each ancillary service and for electricity in addition to the bidder's estimates of its own marginal costs. Given the number of interacting markets, the problem of choosing the profit-maximizing bids would be very complex.[52] But no matter how complex the bidding problem, the optimal bids will normally be at prices greater than marginal cost.

The role of opportunity costs in raising prices can be difficult to evaluate quantitatively by an independent market observer because opportunity costs cannot be directly observed. Similarly, the role of market power in raising prices can be difficult for independent market observers to evaluate quantitatively since the exercise of market power may involve complex bidding strategies. These difficulties translate into monitoring problems, since the two issues are, at least on the surface, observationally equivalent. The simple observation that bid prices exceed marginal cost does not establish how much of the deviation is the product of market power and how much is the product of a purely competitive recognition of opportunity costs.

Divestiture of IOU-Generating Assets under the Restructured System

The degree of vertical integration in the industry was sharply reduced by AB 1890 and subsequent CPUC rulings. Although an investor-owned utility could still include the three separate functions—generation, transmission, and local distribution—the legislation

[52]Consider, for example, a firm bidding to sell electricity into the PX. It knows it could bid to sell the generating capacity as a reserve in an ancillary services market. It knows that if it makes the capacity available as a reserve, there would be some probability the capacity would be called upon to deliver electricity. Thus the opportunity cost would take into account the profits it would expect to earn being available as a reserve and the profits it would earn if it agreed to remain as a reserve but were called upon to generate electricity, with each term scaled by the probability of that event. Thus the firm would need to evaluate the expected prices for ancillary service and the prices it would be paid for electricity, as well as the probabilities of the various outcomes.

ensured that ownership of the three functions would not translate into coordinated decision making among these functions.

However, there was still a concern that common ownership of generation and retail functions would make it difficult to operate a competitive wholesale market and that utility ownership of a large market share of generating capacity would give the utilities market power, resulting in wholesale prices of electricity that would be too high. To address that concern, several options could have been implemented at the time of the restructuring.

First, the restructuring legislation could have allowed the utilities to continue acquiring electricity directly from their own generators, as well as buying it from nonutility generators, either through organized markets or through bilateral contracts. This option would have allowed the utilities to maintain some vertical integration. However, this could have posed incentive problems. First, it was recognized that acquisitions by the distribution component of the utility from the generating component would not be at arm's length, which would be true even if these functions were organized into two companies operating under the same corporate ownership, selling to one another. Prices would be set as intracorporate transfer prices and thus would not be truly arm's length. Therefore, intracorporate transfer pricing for financial regulation would not be dependable; there could well be incentives for increasing or decreasing the transfer price.

In addition, many people believed that a competitive wholesale market would not be possible without divestiture of generating assets. In particular, the local distribution component of the utility would choose to purchase from its own generating component even at a higher cost than electricity offered by new market entrants generating electricity. Once beyond the transition period, those high costs would simply be passed on to the consumers.[53] Since potential entrants in the wholesale market

[53]Any utility that paid its own generating assets a higher-than-competitive price at the wholesale level of the market would increase its own average cost. A regulated utility would pass on these higher costs as higher prices to retail customers. If there were full retail competition, the increase in price of the regulated utility would give its competitors an advantage and the regulated utility would begin to lose market share. However, without such full retail competition one could not ensure that retail competition would fully discipline such wholesale transactions.

would understand these incentives, there would be only reduced incentives for new companies to invest in new generating assets. Existing electric utilities would then not face the market competition in their roles as electricity generators, which was the goal of the restructuring. The desirable benefits of a competitive system might not emerge.

Finally, this plan would not reduce the market power of the utilities in the wholesale markets. They would be net sellers of electricity as corporations. Although they faced average cost regulation for their retail sales, there still would be an incentive to exercise market power in wholesale markets if they were net sellers in those markets.

The CPUC ultimately implemented a two-fold solution. First, the CPUC required and/or strongly encouraged the utilities to divest themselves of their generating assets wherever possible. They were required to divest 50 percent of their generating assets and faced strong financial incentives to divest the remainder. Second, all remaining fossil-fired electricity generation owned by the utility could be sold only through the PX or the CAISO.[54] Together, those rules would ensure that the PX and the CAISO markets would include large volumes of transactions and that utilities would be precluded from any meaningful self-dealing between their wholesale and retail operations and would eliminate or sufficiently reduce their market power in the wholesale markets.

Divestiture would have one other regulatory advantage. Once the CTC was selected as a mechanism for recovering stranded costs, there still was the problem of appropriately measuring stranded costs. If the utilities continued to own the generating plants, there would not be a clean test of how large the stranded costs were. There would be the need for further hearings and possibly litigation to determine the values of the plants the utilities still owned. However, if they sold the plants, the economic loss could be measured easily as the difference between the remaining book value of the generating plant and its sales price. Thus, although this was at most a secondary reason, it did provide some motivation for encouraging the utilities to divest much of their fossil generation capacity.

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[54]More precisely, no costs could be recovered for this generation unless the electricity were sold through the PX or the CAISO.

The incentives for divestiture were successful. As of 2000, only 29 percent of the electricity sold in the state was generated by the utilities and 44 percent was generated through plants that had been divested by the electric utilities and were then owned by nonutility generators. Details of the sales appear in Table 2.2, including which plants were sold to which firms, of what nameplate capacity, the book value, and the sales price.

When generation plants were sold at prices above their book value, the transaction would reduce the amount of stranded costs yet to be recovered through the CTC. Although some plants sold at prices below their book value—and thus were truly stranded costs—most plants sold at higher prices. On net, the divestiture of plants resulted in sales prices that exceeded the remaining book values by more than 70 percent, significantly reducing the amount of stranded costs yet to be recovered through the CTC.

Long- and Medium-Term Wholesale Contracts for Electricity

The divestiture required by the regulations created potential new problems associated with the accounting used to recover stranded costs. As the investor-owned utilities divested their generation assets, there could be incentives for the utilities to enter into long-term electricity purchase contracts with the company buying the generators. If there were linked agreement both to sell the generator and to purchase electricity under a long-term contract from that generator, there was a fear that the financial incentives could distort the selling price and the long-term sales price. Guarding against this potential would require more regulatory oversight.

In addition, there was a fear that long-term contracts could simply substitute for a utility ownership of the generators and a competitive market might not be created. Potential new entrants into the wholesale electricity market might be discouraged in the same way as would be the case absent divestiture of the assets. To ensure that the wholesale markets would not be too thin and there would be too little competition, there was a desire to limit the long-term contracts at the wholesale level.

However, this fear failed to recognize that with growth in electricity use would be growth in the needs for new electricity generation. There would be competition among the suppliers to provide for these new needs. That competition could be through spot markets or market competition for long-term contracts.

TABLE 2.2

Divestiture of IOU-Generating Assets in California

Power Plant	*Purchaser*	*Nameplate Capacity MW*	*Book Value $million*	*Sale Price $million*
Morro Bay, Moss Landing, Oakland	Duke Energy Corp.	2,881	390.2	501.0
Contra Costa, Pittsburg, Potrero	Southern Energy	3,166	318.3	801.0
Geysers (Sonoma & Lake Counties)	Calpine Corp.	1,353	273.1	212.8
	PG&E Subtotal	**7,401**	**981.6**	**1,514.8**
Alamitos, Huntington Beach, Redondo Beach	AES Corp.	4,706	224.1	781.0
Cool Water, Etiwanda, Ellwood, Mandalay, Ormond Beach	Houston Industries	4,019	288.3	277.0
El Segundo, Long Beach	NRG Energy and Destec	1,583	168.8	116.6
San Bernadino, Highgrove	Thermo Ecotek	300	(4.3)	9.5
	SCE Subtotal	**10,607**	**676.9**	**1,184.1**
Encina, Kearny, and other Peakers	NRG Energy and Dynegy	1,347	94.8	365.0
South Bay	San Diego Unified Port District	833	64.4	110.0
	SDG&E Subtotal	**2,180**	**159.2**	**475.0**
	Total	**20,187**	**1,818**	**3,174**

SOURCE: California Energy Commission, www.energy.ca.gov/electricity/divestiture.html

The competition to offer electricity on long-term contracts can be as intense as, or more intense than, spot market competition. Such competition for long-term contracts could allow a buyer of electricity and the seller of electricity to negotiate for a set of mutually satisfactory contractual terms, including appropriate distribution of risks and obligations. Because of the long-term significance of such a contract, the competing sellers tend to put much attention into their offers and the purchasers tend to evaluate the alternative offers very carefully.

Since long-term contracts can include mutually beneficial agreements on risk sharing, the average prices in these contracts could be lower than the expected prices when all competition is based on spot markets. A merchant generator facing the vagaries of water conditions, temperature, gas prices, and day-to-day fluctuations on spot markets may need a higher average market-clearing price to finance new generation than would a merchant generator with a long-term contract, having secure commitments to buy electricity at fixed prices or prices indexed to a reasonable set of external market conditions (such as the natural gas price).

Thus, the linked beliefs that (1) exclusive reliance on spot markets was necessary to assure competition and that (2) negotiated long-term contracts would limit competition were both fallacious. However, these beliefs, even if they were fallacious, seemed to motivate the CPUC in implementing AB 1890 to impose regulatory restrictions against the utilities entering long-term contracts.

To guard against the perceived problems of long-term contracts, once AB 1890 had been passed the CPUC restricted the ability of the investor-owned utilities to enter into any long-term or medium-term contracts. The CPUC required the utilities to acquire all their electricity not already under long-term contract through the PX or CAISO. This restriction went well beyond the long-term contracts. Since the PX and the CAISO originally did not have long-term or medium-term contracts, this requirement effectively prohibited the utilities from entering any long- or medium-term contracts.

The utilities tried as early as 1999 to gain the right to procure electricity on a longer-term basis. In March 1999, SCE filed an application for a pilot program under which it could enter traditional power purchase agreements for electricity and capacity. But the CPUC denied the application. In mid-1999 the PX applied to organize a block-forward market, the FERC approved the application, and the CPUC approved the request by the SCE and PG&E to participate in that market. But the block-forward market allowed contracts for no more than one year. More significantly, such markets, by necessity, offered a standardized contract and did not allow the wide range of contractual agreements that would be desirable for a utility to cover its purchases. But it was a step, albeit a small step, toward allowing the utilities to move away from exclusive reliance on spot markets to acquire electricity. However, until August 2000, the utilities had no right to enter bilateral contracts. The year 2000 events will be discussed in the following chapter.

Although there may have been a reason for discouraging long-term contracts during divestiture, once the divestiture was completed, there was no continuing need to regulate against such contracts. There was already much economic bias discouraging investor-owned utilities from committing to purchase very large quantities of electricity under long-term contracts.[55]

There remains debate about whether the CPUC decisions following AB 1890 were completely responsible for the investor-owned utilities' lack of long-term contracts or whether the utility executives should have entered these contracts with the stockholders bearing the asymmetric risk. Whatever the resolution of this debate, if it ever is resolved, the utilities had been relying dominantly on short-term spot markets for electricity when it became apparent that wholesale prices were rising rapidly. The financial risk was very great.

If investor-owned utilities had, after the restructuring, developed portfolios of contracts, some long-term, some medium-term, and some more flexible, they could have managed some of the risks inherent in the new system.

It is important to note that long-term contracts would not have been a panacea. Nor would they have ensured that the investor-owned utilities would have been able to buy wholesale electricity at lower prices than they could have with short-term contracts. Contracts, whether short-, medium-, or long-term, must have two parties. If the parties knew with significant certainty that the short-term prices would always be higher than the proposed long-term contract price, the rational electricity supplier would never

[55]This issue is discusses more fully in a later section, "Risk Bearing in the Restructured Retail Market."

be willing to offer such a long-term contract. Conversely, if the parties knew with significant certainty that the short-term prices would always be lower than the proposed long-term contract price, the rational electricity buyer would never be willing to accept such a long-term contract. For both parties to agree on a long-term contract price, they must assign a significant probability that short-term prices will be higher than the long-term contractual price and a significant probability they will be lower. Thus, it was never the case that entering into long-term contracts could have dependably reduced electricity acquisition prices from the spot prices.

However, entering such contracts could have substantially reduced the risk of large changes—up or down—in the acquisition cost of electricity. Utilities with such contracts thereby could have guarded against or at least limited the high risk of large fluctuations in the wholesale price of electricity. But that was not to be the case and thus the system was characterized by unnecessarily large risks.

Risk Bearing

Restructuring of wholesale markets created deep economic risks for investor-owned utilities. The wholesale market for electricity promised to be very volatile. Capacity limitations of electricity generators implied that if the system were to approach capacity, marginal cost would increase sharply. All spot sales of electricity would sell at a price equal to this marginal cost. Thus, small differences in requirements for electricity generation could lead to very large differences in the spot wholesale price. Moreover, the utilities were buying most of their electricity on these spot markets because they had divested most of their generating assets and had not entered long-term electricity supply contracts. Thus, total expenditures for acquiring electricity could increase sharply. Although this would not be an issue if the system never approached full capacity, continuing excess generation capacity could not be guaranteed.

The mix of generating facilities increased the risk that the system could approach capacity limitations or face volatile prices. Figure 2.3 shows the 1999 operational capacity of California's three investor-owned utilities in terms of the primary sources of energy used to generate electricity. Data are nameplate capacities.

Over half of the primary energy was natural gas. However, the infrastructure of pipelines to move natural gas in California was extremely limited, as was the capacity of pipelines to bring natural

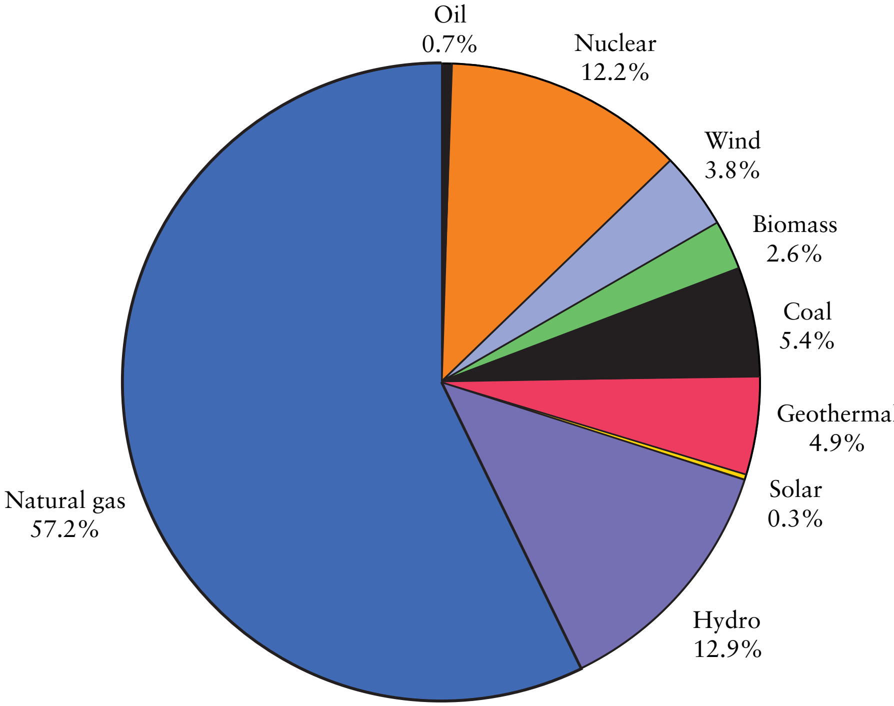

Figure 2.3: 1999 Operational Capacity of California's Three Investor-Owned Utilities

NOTE: Some nuclear, all coal are out of state.

SOURCE: California Energy Commission, www.energy.ca.gov/electricity/operational_capacity.html

gas into California. Therefore, the risk stemming from the high volatility of natural gas prices and natural gas availability in the state was great. Utilities could, and did, sign long-term contracts to buy natural gas. However, such contracts, while reducing this risk, did not eliminate the risk entirely and would not assure that *additional* gas could be obtained when needed.

Another twenty percent of the electricity was generated through hydropower; however, the amount of available hydropower depended on the rainfall during the previous year. More significantly, much of the imports of electricity into California were derived from hydroelectric power in the Pacific Northwest; however, the availability of this electricity was also subject to much uncertainty. In addition, low rainfall in California might accompany those years of low rainfall in the Pacific Northwest. These risks were weakly correlated so that overall risk was increased.

Nuclear power had its own financial risks. In addition to cost and reliability variability, nuclear power faced the political risk that nuclear electric generating plants would be shut down for safety or other environmental reasons.

Divestiture had greatly increased the risk facing investor-owned utilities, although it did not change the inherent system risk. If the utilities had continued to own their generating capacity, they would have faced cost variations that changed with the average generation cost; but because they had divested the assets, they would face cost variations that changed with the marginal cost of electricity. Since the marginal cost is much more volatile than the average cost, divestiture led to far more cost volatility for the investor-owned utilities.

This risk could have been mitigated by long-term contracts, even long-term contracts whose prices were indexed to some measure of average cost of electricity generation—for example, contracts indexed to natural gas prices. However, the CPUC discouraged long-term contracts.

Generation Capacity Risk

Under both the old integrated system and the restructured competitive system there were inherent risks associated with decisions on how much new generation capacity to build, costs of operating existing capacity, and contractual commitments to buy or sell electricity. The fundamental risks associated with costs of fuel to generate electricity were the same under either system, as were the uncertainties about demand growth. If reserve capacity were the same under the two systems, then the risks of short supply of energy would have been the same as well. However, the incentives for capacity investment and utilization are very different under the restructured system than under the old system of vertically integrated utilities.

Under the old integrated system, if all utilities maintained enough reserve capacity to keep marginal generation costs very low, all could still earn sufficient financial returns on the capacity to justify the investment. Thus, utilities could continually invest in new generating capacity and the system could maintain equilibrium with adequate reserve capacity. The retail utility customers would continue paying the cost of the infrequently used capacity and electricity prices would remain systematically high and quite stable over time. Risks would be low because there would be adequate reserve capacity.

With competitive wholesale markets, if all merchant generators maintained enough reserve capacity to assure that marginal generation costs remained low, wholesale prices would remain low; however, most generators could not earn sufficient financial return on the capacity to justify the investment. Investment would be halted, leading to reductions in reserve capacity over time. As reserve capacity dropped, the frequency of price spikes and the average price of electricity would increase. As a result, the incentive to build new generation capacity would increase. If all went well, the system would approach a new equilibrium in which the average price of electricity would be equal to its average cost and the average over time of its marginal cost. In this equilibrium, the system would have less reserve capacity than it would under the old integrated system, causing the average cost and the average over time of price to be lower as well. However, prices would not be stable and risks would be larger because there would be only smaller amounts of reserve capacity.

However, in this new restructured system, reserve capacity might not smoothly approach a new equilibrium, especially if there are long lags from the decisions to invest in new generating capacity until the time that generating capacity goes on-line. It would be quite possible to have periodic times of inadequate reserve capacity and periodic times of excess reserve capacity, classic "boom and bust" cycles. During times of inadequate reserve capacity, wholesale prices would become very high, encouraging much new investment, particularly if investors did not have good information about future conditions; during times of excess reserve capacity, wholesale prices would be very low, discouraging investment. Unless investors could reasonably project future conditions, including the new electricity generation capacity to be constructed, each boom period would set the stage for the next bust; each bust would set the stage for the next boom. Risks would be further increased.

Such wholesale market fluctuations would be very disruptive even if they, on average, did not increase the wholesale electricity price, because they could create political pressures for price stabilization regimes at either the wholesale or the retail level. In addition, if, as was the case in California, retail price controls were already in place, such fluctuations (even short-term ones) would carry with them the possibility of financial crises.

In a competitive market system, encouraging the right amount of reserve capacity is very difficult and, to reduce the risks, careful policy development is needed. Several options can mitigate the risks of "boom and bust" cycles in competitive wholesale markets. First, good market information on projected demand growth, energy efficiency investments, and new capacity investments helps to reduce the cycles associated with myopic decision making. Markets for capacity in addition to markets for the electricity itself could help but have their own difficulties. Long-term contracts between generators and utilities can help match capabilities with needs and reduce the problem.

However, in the period after AB 1890 was signed, none of these options was adopted. The California Energy Commission reduced its role in creating forecasts of future electricity supply and demand conditions. No capacity markets were established, and long-term contracts were discouraged. Thus, the new system created the risk of severe long-term price fluctuations. State agencies did nothing to mitigate those risks.

Wholesale Markets: In Summary

The AB 1890 and CPUC rules created a complicated set of wholesale markets imperfectly coordinated with one another. These markets were given monopoly or near-monopoly status and thus utilities could not escape any problems associated directly with these markets. There remained, however, opportunities for exercise of market power by even those generators with small market share. Risk management options were taken from the investor-owned utilities through divestiture and through overreliance on spot wholesale markets, and volatility in the wholesale markets was nearly ensured. The risk of boom and bust cycles was created. The interplay of these various markets, the resulting bidding strategies of utility-buyers, generators of electricity, electricity marketers, and municipal utilities, and the responses of the CAISO and the PX personnel were all untested at the time of the restructuring.

The associated risks through the wholesale markets were natural implications of this particular system restructuring, and in fact would have been risks of any radical restructuring of the electricity system. The existence of risks does not imply that the undesirable outcomes *will* occur, but that they *may* occur. Risks suggest the need to monitor the wholesale markets and to be prepared to modify the system if the undesirable outcomes in fact come about, something that political leaders need to be willing to do.

RETAIL MARKETS UNDER THE RESTRUCTURED SYSTEM

Creating competitive retail markets was seen to be even more of a challenge, even though there had been extensive experience in other nations, such as Australia, New Zealand, and Great Britain. An ultimate goal was to set up a competitive retail market for electricity; however, at least two factors stood in the way: retail market power and risk management.

Although issues of retail market power and risk management could be, in principle, the same for investor-owned utilities, municipal utilities, and co-ops, the restructuring legislation treated investor-owned utilities differently than the others, if for no other reason than the CPUC had jurisdiction only over investor-owned utilities. Thus, the initial CPUC restructuring Order and AB 1890 applied only to investor-owned utilities, not to the municipal utilities or the co-ops. Since the rules for investor-owned utilities fundamentally changed and the rules for municipal utilities and co-ops did not, most of the following sections will discuss the investor-owned utilities and little attention will be paid to municipal utilities and co-ops.

Local distribution companies had a natural monopoly for the delivery services, the wires, the transformers, and the control systems. In addition, in the short-term they could be expected to have a significant degree of market power for the electricity itself, since electricity had always been sold as a commodity, bundled with the delivery services. Unless retail sales of electricity were unbundled from sales of delivery services, the issue of retail market power would remain.

The system established by the CPUC and AB 1890 therefore allowed delivery services to be decoupled from the retail sales of electricity. The delivery services would still be provided by the investor-owned utilities, operating as monopoly franchises, earning a regulated fee. The commodity itself could be sold by aggregators or generators, or utilities could sell electricity bundled with distribution services.

Investor-owned utilities would operate as regulated retail sellers of electricity subject to review and control by the CPUC, which communicated its intention to move to performance-based regulation, a system whereby performance goals would be negotiated, including cost performance improvements. Nevertheless, regardless of whether such a system was implemented, the investor-owned utilities would remain as regulated firms.

As discussed above, during the transition period, AB 1890 imposed price caps for retail electricity sales by the incumbent utilities during a transition period. This price cap created a dilemma. On one hand, the utilities were being required by AB 1890 to reduce electricity prices for residential and small commercial customers. On the other hand, the CTC magnitude was to be chosen so that all stranded costs would be recovered over a small number of years. Thus with the CTC, the retail price of electricity would be approximately equal to the recent historical electricity component of the bundled retail price, not 20 percent below that level.

The dilemma was resolved through a financial instrument. The utilities were authorized during the transition period to issue "rate reduction bonds" to finance the difference between their cost for electricity (wholesale price plus CTC) and the price-capped retail price, as well as to refinance some of their existing capital equipment. These bonds would be repaid once all stranded costs had been recovered and the CTC was no longer in operation. This plan implied that the retail electricity price reduction that the ratepayers thought they were enjoying would be repaid in later years.

Retail Competition

The CPUC restructuring Order and Assembly Bill 1890 created the opportunity for competition for retail electricity sales, in principle allowing any customers to enter bilateral contracts with electricity suppliers and therefore to bypass the electric utilities, even though the CTC could not be bypassed. The investor-owned utilities would be default sellers of electricity, available for everyone who wished to purchase their retail electricity from these utilities. Their price-capped rates would be available for all customers, even those that switched to other retail suppliers but subsequently chose to return, implying an asymmetrical relationship between the utility and the new competitors: the new competitors could choose whether to take new or returning customers, but the utility could not.

Direct access and retail electricity competition for residential and small commercial customers was made more difficult by the retail price cap. For other electricity suppliers to be competitive on the basis of price, they would have to sell electricity at the investor-owned utility's capped price as well, after paying the CTC; they would have to sell electricity at prices lower than the sum of the wholesale price plus the CTC, losing more money the more electricity they sold.

New entrants could create a distinction in the minds of consumers about electricity delivered from different companies. For example, they could sell "green" electricity, advertised to be generated entirely or primarily by renewable sources. But this component of the market would necessarily be small, if for no other reason than most of the renewable forms of electricity were being sold under contract to the large electric utilities.

Entrants could bundle energy efficiency measures with electricity to help consumers reduce the overall cost of obtaining energy services (for example, warmth, lighting, cooking, clothes drying, refrigeration). The utilities themselves were offering some of these services using some of the public benefit charges included in delivery fees.

New entrants could compete on the basis of price if they marketed electricity primarily to those customers whose loads were less time-variant than typical loads. These could be industrial customers who used electricity at a roughly equal rate throughout the day or whose use of electricity did not vary across the year. For these customers, a new entrant could save money on the wholesale purchases of electricity and might be able to sell electricity at a lower retail price than did the incumbent utilities; however, the new entrant would have to pick its customers carefully.

In principle, some retailers could provide higher reliability of electricity for the industrial or commercial customers for whom reliability was essential or interruptible service for those customers willing to accept service interruptions in exchange for a lower overall bill. However, because electricity was being delivered by the same utility, no matter which firm was selling the electricity itself, it was not clear that an individual electricity retailer could economically offer such services without cooperation from the utility providing the delivery services.

These market opportunities existed for new entrants, but at least during the transition period, they were niche markets. Thus, it could be expected that during the transition period retail competition would be relatively limited.

Risk Management in the Restructured Retail Market

Utilities had historically played the fundamental role of managing retail price risk for their customers, investing in a portfolio of electricity supply assets, some with costs that would vary with market conditions (for example, natural gas–fired units), some with costs that were predictable over time (for example, QF contracts or geothermal units), some with costs that remained low but had less predictable capacities (for example, hydroelectric), and some that provided energy services by using less electricity (for example, energy efficiency investments). For gas-fired units, whose cost could vary with market conditions, utilities would secure long-term contracts for natural gas to reduce the risk.

However, in competitive retail markets, risk management could be a challenge. As it turned out, California didn't come to grips with that challenge until it was too late.

Under the restructured system, management of retail price risk would be left entirely to the competitive marketplace. Given that the investor-owned utilities were required to divest most generation, buy their electricity on spot markets, and avoid long-term contracts, they had few instruments left for managing price risk. During the transition period, retail prices were expected to remain fixed, although the wholesale price of electricity and the CTC would both vary. Once the transition period was over, however, the retail customers could be expected to bear most of the risk of price fluctuations on the volatile wholesale market.

Retail customers remaining with the utilities and wishing for financial stability after the transition period would be expected to purchase financial hedges against fluctuations in wholesale prices. The expectation that many residential and small commercial customers would be willing to engage in sophisticated financial transactions in order to stay with the default utility seems improbable.[56] The more likely outcome, once the transition period was over and consumers began understanding the issues, would be for customers to accept the risk of price variations or to buy electricity from retailers that were willing to offer some assurances of price stability.

New electricity retailers could ensure price stability by providing risk management electricity sales contracts to attract customers

[56] See Ralph Cavanagh, "Revisiting 'the Genius of the Marketplace': Cures for the Western Electricity and Natural Gas Crises," *Electricity Journal* (June 2001).

and purchasing electricity under a mix of different contracts to manage the risk for their customers. Retail prices would vary with wholesale market conditions, but the variations would be greatly moderated.

If a variety of retail sellers emerged after the transition period, customers would be able to purchase retail electricity from retailers who hedged price risk in ways appropriate to their customers, which would require customers to be willing to leave the default utility.

The CPUC could have chosen an alternative wherein utilities could have operated as regulated monopolies, selling primarily to small residential and commercial customers and providing risk management for their customers. The utilities would negotiate a mix of short-, medium-, and long-term contracts to purchase electricity for resale, thus minimizing the risk of price variations.

However, the CPUC rules created strong incentives for default utilities to avoid great reliance on long-term contracts, even when such contracts would be in the interests of their customers. Under the CPUC rules, retail customers could choose to buy from competitors of the investor-owned utilities whenever those competitors offered electricity for sale at a price more attractive than that offered by the investor-owned utilities. However, those competitors were never obligated to sell electricity, nor were they regulated in the price at which they offered to sell. The investor-owned utilities, on the other hand, were obligated to serve all customers, including those who switched back from an unregulated competitor. Moreover, the retail price that they would charge would be based on the average cost of their acquisition of electricity, at least whenever there was no retail price cap.

These differences in obligation to serve and retail price-setting rules between the investor-owned utilities and the unregulated competitors created the incentive against the utilities relying heavily on long-term contracts. Consider what might happen if the regulated utilities did rely very heavily on long-term, fixed price contracts to purchase electricity.

If the spot prices turned out to be much lower than the prices in the long-term contracts, the unregulated firms could offer to sell electricity at a much lower price than could the regulated utilities, and large numbers of customers would shift their purchases to these firms and away from the regulated utilities. With fewer customers, the regulated utilities would purchase smaller quantities of electricity on spot markets; however, because the spot price of electricity would be lower than the contract price, reduced purchases on the spot market would increase the average cost and therefore the price charged to those customers remaining with the regulated utility. The price increase would cause even more customers to leave the regulated utility, thereby further increasing the price for those remaining. The greater the fraction of electricity the utility had contracted to purchase under long-term contracts, the more severe would be this "spiraling downward" process. If the purchases were dominantly long-term contracts, then the utility could end up obligated to purchase more electricity than they could sell.

If, on the other hand, spot prices turned out to be much higher than the average acquisition cost (including the cost of the long-term contracts), customers would abandon the unregulated competitors and would purchase electricity from the utilities. This, in fact, happened when the spot prices of electricity started rising in summer 2000. The increased retail sales would have required increased spot market purchases, thereby increasing the average cost and the regulated price.

But the unregulated retailers are not restricted in this manner. In particular, they need not allow their customers to ebb and flow this way. Retailers offering risk management contracts could choose to sell to only those customers willing to sign year-long or longer time period contracts. Thus, if spot prices were to drop sharply below the average acquisition price, these customers would be precluded from leaving. Moreover, they could base new contracts on their expectations of market conditions. If spot prices were to rise sharply above the average acquisition price, they need not take new customers or they could charge the new customers based on the prices for new wholesale contracts.[57]

This difficulty could be overcome. To do so, however, the incumbent utility would have to be allowed to impose contractual constraints on its existing customers,[58] stopping them from leaving

[57]In addition, the unregulated competitors could earn profits when the spot price was above the contractual price and would take losses when the spot price was below the contract price. But since long-term contracts typically have prices roughly equal to the expected average spot prices, then over time these unregulated firms would not be disadvantaged by long-term contracts in the same way as the regulated utilities would be.

[58]For example, all customers could be given a limited time (say, six months) to sign a one-year contract to purchase their electricity from the utility. If they do not do so, the utility would no longer be obligated to sell electricity to them. Similarly, if they switch to another provider, then they might be allowed to switch back to the utility only if they sign a one-year contract with a price designed such that their purchases from the utility will not increase prices facing the rest of the customers.

when spot prices dropped, and be allowed to limit the new customers it would serve, particularly when spot prices increased above average wholesale acquisition costs. But the CPUC did not provide these options to the investor-owned utilities.

Risk problems for the utilities would be especially threatening during the transition period because the price caps disabled a central adjustment mechanism. Typically, production costs are translated through wholesalers and retailers into consumer price increases, which motivate reductions in demand for electricity, in turn placing downward pressure on wholesale prices. During the transition period, however, the retail price caps would disable this process. Thus, the natural economic process limiting the magnitude of wholesale price increases would be missing and the risks associated with large wholesale price increases would be amplified.

In addition, during the transition period, since retail prices were capped, increases in wholesale prices would directly reduce retail margins, possibly resulting in a negative retail margin. Some retail risk would be hedged to the extent the utility generated electricity, but since each investor-owned utility divested most of its generation capacity, each would be a large net wholesale buyer and a large net retail seller of electricity. Thus, risk of wholesale price increases would be borne disproportionately by the utilities even if wholesale prices soared well above retail prices and utilities were losing money on every megawatt-hour of electricity sold.

Generally, however, a company losing money on everything it sold could sharply reduce or halt its sales. But the utilities were required to sell electricity to everyone who turned on their lights, appliances, machinery, or air conditioning. Thus, they were precluded from that normal adjustment process.

In summary, the restructured system put the utilities in an untenable risk-bearing posture, increasing risk during the transition period in three ways:

1. Wholesale price fluctuations would not be moderated by market forces.
2. Wholesale price increases would result directly in financial losses, since none could be passed on as retail price increases.
3. The utility could not reduce transactions when retail margins became negative. Worse yet, its obligation to take back customers implied that its transactions would increase when the loss per transaction became large.

Thus, during the transition period, investor-owned utilities, facing a profoundly high degree of risk, were precluded from most strategies for hedging or reducing risk. Traditionally "safe," blue chip investments, the investor-owned utilities were placed into a posture more risky than that facing most companies.

Although these were all important risks, at the time AB 1890 was passed, all participants anticipated that the cost of wholesale electricity would remain well below the retail price,[59] and the economic isolation between producers and consumers would not create a problem. However, no one could be sure this would be the case. The risks were large, although many of the participants in the process may have underestimated these risks.[60]

These risks could be viewed as merely theoretical, since anyone could have reasonably expected there to be one protection in the unlikely event of soaring wholesale prices. The newly restructured system was a politically designed process. The high risks were not inherent to the economic system but were the results of definable design flaws in the regulatory system. At the time of the restructuring, it would have been reasonable to believe that if the perfect storm descended on the state, the political system would adjust to the new reality. Unfortunately, as has become painfully apparent, this reasonable belief has proved to be disastrously wrong.

MUNICIPAL UTILITIES

California's many municipal utilities, serving 22 percent of California's customers, were allowed to continue operating as they had prior to the restructuring. Each municipal utility had a governing board, either appointed or elected within the municipality, responsible for managing the utility to benefit residents. Typically, municipal utilities were expected to cover their costs through sales of electricity. The governing boards retained the ability to increase retail prices at which the municipal utility sold electricity, if the need arose. These utilities typically purchased electricity using a

[59]More precisely, the cost of wholesale electricity would remain well below the retail price of the electricity itself, the retail price charged to customers minus the fixed costs of wires and other distribution services.

[60]The published analyses, including those done by the California Energy Commission and those published through the academic community, all forecast relatively low wholesale prices.

mix of short-, medium-, and long-term contracts so that they were hedged from rapidly changing wholesale prices.

Municipal utilities, therefore, differed sharply from the investor-owned utilities in that they retained all capabilities to manage their risks. As it would turn out, this ability to manage risk was fundamental in differentiating the impacts of the California electricity crisis on the municipal utilities from the impacts on the investor-owned utilities.

IN SUMMARY

California began the decade of the 1990s with a completely vertically integrated electricity system that had been working reasonably well as a regulated system. However, there were opportunities for improvement.

Some reasons for restructuring the system were good. The old system encouraged the investor-owned utilities to build too much capacity at too high a cost. It discouraged appropriate risk bearing on the part of the utilities and discouraged innovation. It included incentives for the utilities to favor their own generators and to avoid purchases from new competing alternatives.

Some other reasons were not good. The advocates of restructuring expected significant immediate cost reductions, pointing to the high average prices of California retail electricity. These high prices, however, were based primarily on the contracts to purchase electricity from qualifying facilities and on the high capital cost nuclear power plants. But the high-priced QF contracts had been forced by the CPUC. Moreover, at the time the nuclear power plants were initiated, it had been expected that they would provide low-cost power. A market restructuring would not eliminate the historical costs, no matter who was responsible for past decisions. Market traders expected that the particular California restructuring would create profit opportunities for their firms, a good reason from their perspective, but not a good reason from California's perspective.

Although some reasons that advocates advanced for restructuring were weak, there were sufficient good reasons to proceed. The process of analysis and debate from the early 1990s through the signing of the bill was remarkably open and allowed many opportunities for knowledgeable parties to participate in discussions. Many analysts, observers, and especially stakeholders joined the debate. In short, the process, through the signing of AB 1890, was remarkable for the debate that was encouraged and that influenced the final legislation. However, the broad participation may have resulted in a system designed by committee, with features beneficial to some participants, but harmful for the overall design.

Like all legislation, AB 1890 represented a series of compromises and included some mistaken judgments; however, it should not be judged as the final product. Rather it should be seen as a framework for further restructuring, since so many elements out of the system would require continued implementation and continued change.

Nevertheless, absent these additional changes, the restructured system left the investor-owned utilities and the state in a more risky situation than appropriate. From the perspective of those times, it was reasonable to believe that the state would pass through the transition period unscathed and would be able to move forward, once the stranded costs had been recovered, into a new era. However, even though not recognized, the risk was there from the very beginning that things could go wrong. And go wrong they did.