ASSESSING THE “GOOD OLD DAYS” OF COST-PLUS REGULATION

A report on trends in electricity prices during the emerging competitive regime from 1980 to 1999, plus a brief look at risk management then and in the future

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BOSTON PACIFIC COMPANY, INC.
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BOSTON PACIFIC COMPANY, INC.
EXECUTIVE SUMMARY

In the wake of well-publicized events in California, some have expressed a longing for the good old days of cost-plus regulation. It is important, however, to recall that these good old days were not all that good. For example, in the introduction to its Order 888, the Federal Energy Regulatory Commission (FERC) reminds us that, between 1970 and 1985, inflation-adjusted electricity prices increased 25 percent for residential customers and increased 86 percent for industrial/commercial customers. These price increases drove the start of electricity competition in the mid-1980s.

That significant increase before 1985 is in sharp contrast to the significant decrease we found in inflation-adjusted electricity prices during the subsequent 15-year period in which the nation began evolving toward a competitive electricity business. In the 1985-1999 period, inflation-adjusted electricity prices decreased on average by 30 percent for residential customers and by 36 percent for industrial/commercial customers.

Moreover, the decreases were widespread. In our sample, 84 percent of the utilities exhibited greater than a 20 percent decrease in inflation-adjusted prices for residential customers; 94 percent reported greater than a 20 percent decrease for industrial/commercial customers.

Although these price decreases were clearly realized under an evolving competitive regime, we cannot argue that the price decreases were solely the result of the move to competition. Even under a cost-plus regime, prices would have decreased as fuel prices fell, inflation slowed, and power plants became fully depreciated. But there are additional reasons to conclude that competition played a significant role in driving prices down.

Those additional reasons include the fact that larger price decreases occurred where competitive pressure was the greatest. For example, industrial/commercial prices fell more than residential prices (36 percent vs. 30 percent); in the mid-1980s, the primary competitive threat came in the form of on-site cogeneration for these customers. Similarly, in the “all customers” class, which includes wholesale electricity sales (sales-for-resale), the price decline is 36 percent for the class as a whole. Competition is, perhaps, most aggressive in the wholesale arena, and this indicates prices fell significantly there.

Competition, especially that driven by open access, should also lead to a convergence of prices across utilities. Open access increased wholesale competition between utilities. As expected, prices did indeed converge with the average difference among utilities (the standard deviation) for the “all customers” class, decreasing by 49 percent during the 1985-1999 period.

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1 See Methodology section for a detailed explanation of the sales included in the “all customer” class.
Moreover, even if the recent price decreases could be attributed entirely to declines in fuel prices, this also can be traced indirectly to competition in other energy businesses. The Organization of Petroleum Exporting Countries’ (OPEC) hold on oil prices was broken as the oil price spikes of the 1970s led to aggressive marketplace responses from both suppliers and consumers. Natural gas prices also fell as that business was restructured.

What about the future? Will consumers do better under a competitive or regulated regime? When looking to the future, only one thing is clear: Neither regime can guarantee a future without problems. Indeed, to judge whether consumers will be better off, one must assess the relative effectiveness of the two regimes in handling such problems. The goal is to minimize those problems and to give consumers a way to protect themselves when problems do occur. What some call “problems” are best viewed as risks inherent in the electricity business, and the effort to address these challenges is best termed “risk management.”

Better risk management is better for consumers, and it is clear from other commodities that risk management is better under a competitive regime. Indeed, the prudence reviews of cost-plus regulation are a disincentive to risk management. In sharp contrast, risk management in electricity so far has evolved well under the competitive regime. With the fixed price, performance-based contracts brought on by the Public Utility Regulatory Policies Act (PURPA), significant risks were shifted away from consumers to suppliers and then on to other parties in the best position to minimize those risks. Today, merchant plant developers have been willing to take on market risk and have come up with innovative ways to manage that risk. The new frontier of risk management is to allow consumer choice so that risk management can be tailored to the needs of specific types of customers. Clearly different customers have different tolerances for risk, and competitive power suppliers are ready, willing and able to offer products to meet those different tolerances.

Finally, it is important to see that what happened in California, in part, resulted from market rules that prohibited the most basic risk management. Specifically, utilities were required to take on the risk of selling at a fixed price to customers, but not allowed to manage that risk by arranging contracts with fixed-price supplies to serve those customers.
I. INTRODUCTION AND SUMMARY

Historical Background

In the wake of well-publicized events in California, some have expressed a longing to return to the “good old days” of cost-plus regulation.² At the outset, it is important to recall that the good old days were not so good. There were price shocks for customers in the 1970s and early 1980s because of OPEC-driven spikes in oil prices, and cost overruns and poor performance at large baseload power plants. In this regard, FERC stated:

“…expensive large baseload plants for which there was little or no demand, came onto the market or were in the process of being constructed. Accordingly, between 1970 and 1985, average residential electricity prices more than tripled in nominal terms, and increased by 25 percent after adjusting for general inflation. Moreover, average electricity prices for industrial customers more than quadrupled in nominal terms over the same period and increased 86 percent after adjusting for inflation.”³

PURPA, a law many see as the first step toward bringing competition to the U.S. electricity business, was meant to address these problems encountered under cost-plus regulation. PURPA encouraged more efficient use of oil and natural gas by promoting fuel-efficient technologies, such as cogeneration, or the displacement of those fuels altogether by promoting renewable fuels. By leading to the sale of power under pay-for-performance, fixed-price contracts, PURPA shifted the risk of cost overruns and poor performance away from the ratepayer to the supplier.

PURPA started a slow but steady move toward competition. As seen in Table One, there were many important legal and regulatory events on the journey toward competition from 1980 to today. These events include (a) administrative actions such as the first use of competitive bidding under PURPA in 1984, (b) court actions conditioning a merger with an open-access requirement in 1988, (c) passage of Energy Policy Act in 1992, and (d) FERC Orders 888 and 2000, which broadened and deepened the application of open-access transmission.

² We use the term “cost-plus” regulation instead of “cost-based” regulation because prices in a competitive market also are cost-based; competitive pressure forces prices to cost.
³ FERC Order 888, page 14, Docket Nos. RM95-8-000 and RM94-7-001.
### TABLE ONE: EVENTS IN THE EVOLUTION OF A COMPETITIVE U.S. ELECTRICITY BUSINESS

<table>
<thead>
<tr>
<th>TIME FRAME</th>
<th>KEY LEGAL/REGULATORY EVENTS</th>
<th>COMPETITIVE EFFECT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Late 1970s/Early 1980s</td>
<td>• Congress passes Public Utilities Regulatory Policies Act of 1978 (PURPA)</td>
<td>• Encourage nonutility generation and fixed-price contracts</td>
</tr>
<tr>
<td></td>
<td>• Supreme Court upholds PURPA, American Paper Institute v. AEP Service Corp. (1983)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• States begin to implement PURPA</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• First RFP (1984)</td>
<td>• Wholesale competition emerges</td>
</tr>
<tr>
<td></td>
<td>• FERC bidding NOPR (1988)</td>
<td>• Competitive bidding becomes the norm</td>
</tr>
<tr>
<td></td>
<td>• FERC Order 436 (1985)</td>
<td>• Natural gas: encourage unbundling and open access in transportation</td>
</tr>
<tr>
<td>Mid-1980s</td>
<td>• PacifiCorp merger (1988)</td>
<td>• Authorize market-based electricity prices and encourage open access</td>
</tr>
<tr>
<td></td>
<td>• FERC AEP Order (1994)</td>
<td>• Allow exempt wholesale generators</td>
</tr>
<tr>
<td></td>
<td>• Other market-based pricing and merger cases before FERC</td>
<td>• Natural gas: market-based prices; require open access and unbundling</td>
</tr>
<tr>
<td></td>
<td>• Energy Policy Act/Sections 211 &amp; 212 (1992)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Natural Gas Wellhead Decontrol Act (1989)</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• FERC Order 636 (1992)</td>
<td></td>
</tr>
<tr>
<td>Late 1980s/Early 1990s</td>
<td>• PJM, NYISO, ISO-NE, ERCOT ISO start operation (1996-1999)</td>
<td>• Require independent control of transmission system through ISOs/RTOs</td>
</tr>
<tr>
<td></td>
<td>• FERC Order 2000 (1999)</td>
<td>• Divestiture of utility power plants</td>
</tr>
<tr>
<td></td>
<td>• FERC Order 888 (1996)</td>
<td>• Growth of merchant power plants</td>
</tr>
<tr>
<td></td>
<td>• States implement competition (1992-present)</td>
<td></td>
</tr>
<tr>
<td>Early to Mid-1990s</td>
<td>• Open access codified</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Expanded retail competition</td>
<td></td>
</tr>
<tr>
<td>Late 1990s/Early 2000s</td>
<td>• Require independent control of transmission system through ISOs/RTOs</td>
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<td></td>
<td>• Divestiture of utility power plants</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Growth of merchant power plants</td>
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</tbody>
</table>
Judging Competition So Far

To come to a judgment on electricity competition to date, it is not enough to conclude that the good old days of cost-plus regulation were not always so good. We also must judge whether the onset of competition made things better. As a basis for this judgment, a 20-year history of prices (1980-1999) for 60 investor-owned utilities (IOUs) was developed. We use the term “prices” to reflect the fact that we are reporting actual revenue per kilowatt-hour (kwh) from electricity sales, not the rates listed in tariffs per se. When available, we calculated prices for these customer classes: all customers, residential customers, and industrial/commercial customers.

An extensive utility-by-utility database was created using data provided by the utilities themselves. We found that in inflation-adjusted (“real”) terms, prices trended lower throughout the period. For all customers as a group, real prices fell 31 percent, on average, over the 1980-1999 period and fell by 36 percent, on average, over the 1985-1999 period. This is a significant decline and is in sharp contrast to the significant increases in real prices reported by FERC for the 1970-1985 period.

No one would attribute the reduction in real electricity prices solely to the onset of competition. Fuel prices fell, inflation slowed, and high-cost plants were depreciating. However, as the nation steadily moved toward wholesale competition, consumer prices for electricity steadily declined. A closer look at the data yields other reasons to believe competition played a significant role in the price decline. In sum, these other reasons are (a) the biggest declines occurred for the customers with the greatest competitive pressure and (b) prices converged across utilities. Specifically:

- Real prices for industrial/commercial customers fell more than those for residential customers, 32 percent and 21 percent, respectively, in the 1980-1999 period; they fell 36 percent and 30 percent in the 1985-1999 period. Much of the competitive pressure from PURPA was exerted through the threat of on-site cogeneration to serve these large industrial/commercial customers.

- Similarly, the 36 percent price decrease for all customers also is at the high end. This reflects the fact of lower prices at wholesale (sales-for-resale) during the 1985-1999 period; with competition, perhaps, most aggressive in the wholesale arena.

- As one would expect from wholesale competition, especially that driven by open transmission access, prices across utilities converged significantly. Whereas previously, limited transmission access blocked competition, open transmission access meant that utilities faced more aggressive wholesale competition. Under wholesale competition, utilities face competition from utilities in other geographic regions, which forced their prices closer to each other. The standard deviation of prices among our...
sample of 60 utilities fell by 44 percent during the 1980-1999 period, and by 49 percent during the 1985-1999 period for all customers.

- The decline and convergence of real prices were greater in the 15-year period from 1985-1999, during which competitive pressure gained a stronger hold than in the 20-year period from 1980-1999. Convergence is an indicator of the level of competition between utilities to win wholesale business.

Even if the decline in prices were to be attributed primarily to fuel price declines, this also can be said to result indirectly from competition. OPEC’s hold was broken because the rise in world oil prices elicited a significant marketplace response from suppliers and customers, and natural gas prices fell as that industry was restructured.  

**Looking To The Future**

What about the future? Will consumers do better under a competitive regime?

When looking to the future, only one thing is certain: no one can guarantee a problem-free future under either a competitive (market-based) or cost-plus regulatory regime. Fuel prices will rise and fall. Prices in longer-term contracts may be above or below spot market prices. At any point in time, prices to consumers may be above or below what they were in the past. New technologies may or may not be developed that will render today’s infrastructure obsolete.

Indeed, to assess whether consumers will be better off in the future under a competitive or regulatory regime, one must assess the relative value of the two regimes in handling such problems. The goal would be to identify the regime that is likely to minimize the number of problems that occur and the one that gives consumers a way to protect themselves when problems do arise. What we call “problems” are best viewed as risks inherent in the electricity business. Efforts to address these challenges are best viewed as risk management.

**With cost-plus regulation, there is no incentive to manage risk of either development costs or variable operating costs.** Utilities have no incentive to take action to address uncertainty because in most cases there is the opportunity, no matter what occurs, to “pass through” all costs to ratepayers. The only limit on costs being passed through is an after-the-fact prudence review, and prudence review is likely to deter risk management because it may penalize a utility that takes an action that proves to be wrong.

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4 Daniel Yergin in *The Prize: The Epic Quest for Oil, Money and Power* identifies several market factors which contributed to the significant decline in oil prices by 1985: (a) demand for OPEC oil dropped 43 percent between 1979 and 1983; (b) other countries explored for and produced oil in other areas (Mexico, North Sea, Malaysia, China, etc.); and (c) energy conservation made the U.S. 32 percent more oil efficient by 1985.
PURPA introduced a whole new era of risk management by ushering in the era of fixed-price, performance-based power purchase agreements (PPAs). Confronted with these PPAs, a fairly standard approach to risk management took hold. Under the new era of PPAs, project developers began to shift risk to the contractual parties most able to manage that risk.

The major change in risk allocation in the late 1990s is that project developers will now take on market risk. That is, rather than project developers being guaranteed a set price and regulators being guaranteed a level of operation, developers now accept swings in price and demand brought on by variations in market conditions. Plants accepting at least some level of market risk are often called merchant plants.

The next frontier in risk management for the U.S. market is to tailor electricity supply offers to the risk needs of individual consumers. With long-term PPAs, consumers are presumed to want protection against any variation in prices. If a spot market purchase is made, consumers are presumed to want to accept prices dictated by the market, and thereby, accept possibly great variation. Clearly, all customers do not have the same tolerance for risk, and it is unlikely that either extreme (no variation, or 100 percent variation) is the norm. Competitive power suppliers are ready, willing and able to tailor offers to the risk tolerance of each customer.

Finally, a note on risk management in California is warranted. Events in California occurred not because of new risks introduced by competition, but because market rules blocked utilities from conducting the most basic risk management. By law, utilities had to sell at a fixed price to consumers but buy at a variable price in the state’s spot market. It was inevitable that the two prices would get out of line. That is what left the state without creditworthy buyers. Even the most rudimentary risk-management analysis would show that the utilities must match, to some degree, the fixed-price sales with fixed-price supply contracts.
II. METHODOLOGY FOR THE 20-YEAR PRICE STUDY

The goal of this analysis was to provide a straightforward, quantitative assessment of the effect of competition so far in the U.S. electricity business. We decided to ask two questions in this regard: (a) did prices in inflation-adjusted (“real”) terms increase or decrease; and (b) did prices across utilities get further apart (diverge) or closer together (converge)?

To answer these two questions, we collected data on sales revenue plus the quantity of sales in megawatt-hours (mwh) for three customer groups: all customers, residential customers, and industrial/commercial customers. The “all customers” class includes residential and industrial/commercial, plus wholesale electricity transactions and other, typically smaller, customer categories. Utilities categorize revenue streams and mwh sales in different ways, but as long as the two were categorized in the same way for a specific utility, they were included in the “all customers” class. Depending on the utility, the “all customers” category might include wholesale sales plus sales to customer classes such as government and streetlights. There were only three utilities in which wholesale revenues and sales data was not available for some of the years. Therefore, for the vast majority of utilities, wholesale electricity customers are included in the all customer price. We felt it was important to include wholesale customers in our price calculations since competition was felt most strongly in the wholesale arena, and this broader category is more likely to demonstrate the gains from competition.

We pursued approximately 100 IOUs, but the necessary data were available for only 60 of them. We focused on the 1980-1999 period because the first efforts to move to competition began with PURPA around 1980. We also report results for the period starting in 1985 because competition had more strongly taken hold by that year. Given the timing of this study, data for 2000 was not available for all the utilities, so 1999 is the end point of our analysis. Even putting aside the unique problems of California, we understand that prices may have risen elsewhere in 2000. To appropriately judge the effects of competition, it is important to look over a 15- to 20-year period, as we have done here, rather than focus on a single year or a single geographic location.

The revenue and mwh information was gathered through 10-K filings, FERC Form 1s, Annual Reports, and statistical supplements to annual reports. Some of the information was forwarded to us directly from the individual IOUs after conversations with various departments within the organizations. Boston Pacific very much appreciates the assistance of these utilities.

More than 325 spreadsheets and charts were created from this extensive database. Calculations from these spreadsheets yielded nominal and real electricity prices for residential customers, industrial/commercial customers, and all customers for each of the 60 IOUs. Nominal prices are equal to revenue divided by mwhs sold for each customer class. Real prices use the U.S. Consumer Price Index (CPI) as the deflator to convert the
nominal prices in inflation-adjusted terms; the base years for the CPI are 1982-1984.\textsuperscript{5} We used CPI as a deflator because we are showing purchasing power and its trade-off from a household or corporate budget perspective.

The data for each IOU were then linked to an aggregate database to calculate the average decline in real prices for each customer class and to develop the standard deviation of prices across all of the IOUs in the study for each year in the analysis. This standard deviation statistic shows the variability of real prices across all utilities for each year and allows us to test the convergence of prices over the period of the study. The decrease in standard deviation during the 1980-1999 period means that prices were becoming less different from one utility to another; that is, real electricity prices began to converge.

After calculating the price data, Boston Pacific developed a statistical distribution of the percentage decreases in real prices exhibited by IOUs. This is done to determine whether the majority of IOUs experienced similar price declines, or whether the real price declines were limited to a few IOUs.

The next section will discuss the results of our data collection and analysis.

\textsuperscript{5} Economic Report of the President, Year 2000, Table B-60, CPI-Urban “All items.”
III. RESULTS OF THE 20-YEAR PRICE STUDY

As a group, the data from 60 IOUs revealed a substantial drop in real prices in the late 1980s and then a steady decline to 1999. Substantial convergence of prices also is shown. In the sections that follow, we will discuss the results of our study in more detail. Table Two presents a summary of our findings for both the 1980-1999 period and the 1985-1999 period.

**TABLE TWO**
SUMMARY OF RESULTS

<table>
<thead>
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</thead>
<tbody>
<tr>
<td><strong>Average Reduction in Real Prices</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>All Customers (including wholesale)</td>
<td>31%</td>
<td>36%</td>
</tr>
<tr>
<td>Residential Customers</td>
<td>21%</td>
<td>30%</td>
</tr>
<tr>
<td>Industrial/Commercial Customers</td>
<td>32%</td>
<td>36%</td>
</tr>
<tr>
<td><strong>Convergence</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>All Customers (including wholesale)</td>
<td>44%</td>
<td>49%</td>
</tr>
<tr>
<td>Residential Customers</td>
<td>27%</td>
<td>32%</td>
</tr>
<tr>
<td>Industrial/Commercial Customers</td>
<td>31%</td>
<td>38%</td>
</tr>
<tr>
<td><strong>Share (%) of Utilities With Greater Than 20% Decrease in Real Prices</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>All Customers</td>
<td>87%</td>
<td>93%</td>
</tr>
<tr>
<td>Residential Customers</td>
<td>64%</td>
<td>84%</td>
</tr>
<tr>
<td>Industrial/Commercial Customers</td>
<td>92%</td>
<td>94%</td>
</tr>
</tbody>
</table>

1Sample Size of All Customers (including wholesale) is 60, for Residential and Commercial/Industrial class, it is 50
Real Price Decline

All Customers

Figure One shows the average decline of prices for all customers for the 60 IOUs studied for this analysis:

FIGURE ONE
ALL CUSTOMERS CLASS (INCLUDING WHOLESALE): GRAPH OF YEAR-BY-YEAR REAL PRICES

As can be seen from this Figure, real prices for all customers grew from 1980-1983, declined slightly from 1984-1986, dropped significantly by 1988, and declined steadily by 1999. In all, the average reduction in real prices to all customers was 31 percent from 1980-1999 and 36 percent from 1985-1999. These results are based on the simple unweighted average of the 60 IOUs.

Any average can be misleading if it reflects a skewed distribution. For example, the average 36 percent decline in real prices for the group might be misleading if it reflected a few utilities with very high decreases and the rest with small decreases in real prices. To explore this concern, Table Three shows the distribution of real price declines; that is, it shows the number of utilities with price declines in various percentage ranges.
TABLE THREE
ALL CUSTOMERS CLASS (INCLUDING WHOLESALE): DISTRIBUTION OF
% DECLINE IN REAL PRICES

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td></td>
<td># of Utilities</td>
<td>% of Total</td>
</tr>
<tr>
<td>&lt; 0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>0% - 10%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>11% - 20%</td>
<td>4</td>
<td>7%</td>
</tr>
<tr>
<td>21% - 30%</td>
<td>13</td>
<td>22%</td>
</tr>
<tr>
<td>31% - 40%</td>
<td>22</td>
<td>37%</td>
</tr>
<tr>
<td>41% - 50%</td>
<td>13</td>
<td>22%</td>
</tr>
<tr>
<td>51% - 60%</td>
<td>8</td>
<td>13%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>60</td>
<td>100%</td>
</tr>
</tbody>
</table>

Table Three shows that most utilities had significant declines. As seen in the Table, for the 1985-1999 period, 59 percent of the utilities had a real price decline in the range of 21 percent to 40 percent, and 94 percent had declines greater than 20 percent.

Residential Customers

Figure Two is a graph of year-by-year real prices for the residential customers class. The reduction in the real residential prices showed historical behavior that is similar to the “all customers” class, but its reductions are less, showing a decline of 30 percent from 1985-1999 and 21 percent from 1980-1999.
Table Four displays the distribution of real price declines for the residential customers. Most utilities show similar declines. Of the 50 utilities providing such data for the 1985-1999 period, 64 percent reported declines in the 21 percent to 40 percent range, and 84 percent reported declines greater than 20 percent.
TABLE FOUR
RESIDENTIAL CUSTOMERS CLASS: DISTRIBUTION OF
% DECLINE IN REAL PRICES

<table>
<thead>
<tr>
<th>% Reduction</th>
<th>Utilities</th>
<th>% of Total</th>
<th>Utilities</th>
<th>% of Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 0%</td>
<td>1</td>
<td>2%</td>
<td>4</td>
<td>8%</td>
</tr>
<tr>
<td>0%-10%</td>
<td>1</td>
<td>2%</td>
<td>2</td>
<td>4%</td>
</tr>
<tr>
<td>11%-20%</td>
<td>6</td>
<td>12%</td>
<td>12</td>
<td>24%</td>
</tr>
<tr>
<td>21%-30%</td>
<td>15</td>
<td>30%</td>
<td>18</td>
<td>36%</td>
</tr>
<tr>
<td>31%-40%</td>
<td>17</td>
<td>34%</td>
<td>12</td>
<td>24%</td>
</tr>
<tr>
<td>41%-50%</td>
<td>10</td>
<td>20%</td>
<td>2</td>
<td>4%</td>
</tr>
<tr>
<td>51%-60%</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Total</td>
<td>50</td>
<td>100%</td>
<td>50</td>
<td>100%</td>
</tr>
</tbody>
</table>

Industrial/Commercial Customers

Price reductions were largest for the industrial/commercial customers. That class shows a 36 percent decline from 1985-1999 and 32 percent from 1980-1999. Figure Three shows the pattern of year-by-year real prices for this class of customers. The pattern is similar to the other classes but reflects a steeper decline.
Table Five displays the distribution of real price declines for the industrial/commercial customers class. Again, for the 1985-1999 period, most of the utilities reported significant declines, with 54 percent reporting declines in the 21 percent to 40 percent range, and 94 percent reporting a decline greater than 21 percent.
REAL PRICE CONVERGENCE

Convergence of prices in this study is defined as the narrowing of difference in prices from one IOU to another. For example, if there were two IOUs and their prices were $0.05/kwh and $0.08/kwh respectively in year one, and $0.04/kwh and $0.06/kwh respectively in year two, the prices converged during the two years, moving from a $0.03/kwh difference in year one to $0.02/kwh difference in year two. Competition should drive prices to converge across IOUs because each utility is competing to a greater extent on price.

For this study, the standard deviation across the 60 utilities for each year of the study measures the geographic dispersion of prices. Decreased standard deviation means that customers were facing increasingly similar prices across utilities. The result for all customers is shown in Figure Four below:
Although prices did converge (standard deviation declined) from 1980-1999, the standard deviation did not decline as steadily as was shown in our study of real price behavior. The “all customers” class showed significant convergence from 1985-1989, minimal convergence from 1989-1996, and then generally steady convergence to 1999. This would indicate that the decrease in oil and natural gas prices in the mid- to late 1980s played an important role in the convergence in real prices across IOUs during this time period. However, competitive pressures would still lead to price convergence as utilities compete with neighbors regionally. For the “all customers” class, convergence in real prices increased 49 percent from 1985-1999 and 44 percent from 1980-1999. This means that customers across the U.S. were increasingly faced with similar electricity prices. Figures Five and Six show the standard deviations in the residential and industrial/commercial price classes.
The residential price convergence graph shows more of a growth in dispersion of prices (increase in standard deviation) after the initial fall from 1984-1989 than is experienced by the “all customers” class. However, the decline in standard deviation restarted in 1994 and ran through 1999. Residential prices converged 27 percent from 1980-1999 and 32 percent from 1985-1999.
Industrial/commercial prices converged 31 percent from 1980-1999 and 38 percent from 1985-1999. This class’ historical trend line is similar to that of the residential prices, but (a) the decrease in standard deviation from 1986-1989 is more significant and (b) the interim growth from 1989-1994 is not as steep.
IV. LOOKING TO THE FUTURE

Risk Management is the Key

What about the future? Will consumers do better under a competitive regime?

To assess whether consumers will be better off in the future under a competitive or a regulatory regime, one must assess the relative value of the two regimes in addressing uncertainty or problems. The problems could concern changes in fuel prices, the adequacy of power plant or transmission infrastructure, or the introduction of new technologies. What we call “problems” are best viewed as risks inherent in the electricity business. And efforts to address these problems are best viewed as “risk management.” Consumers are better off with better risk management.6

The New Risk Management Brought on by PURPA

With traditional cost-plus regulation, there is no incentive to conduct risk management. Utilities may run a huge number of scenario projections, and they do care about uncertainty, but utilities have no incentive to take action to address uncertainty because there is the opportunity, no matter what occurs, to pass all costs through to ratepayers. The only limit to pass-through is an after-the-fact prudence review. Prudence review is likely to deter risk management because it may penalize a utility that takes an action that proves to be wrong. A 1997 report by the National Regulatory Research Institute for the Kansas Corporation Commission summarizes this point well:

“When the local utility acts as the “designated” purchaser of power, its decisions, no matter how competitive wholesale power may be, become largely immune from market discipline and, instead, subject to the judgment of regulators. This means that retail customers would continue to bear the brunt of bad decisions, thereby at most only marginally affecting the incentive of the utility to make better decisions. Retail competition would give customers the opportunity to negotiate credit and risk-management instruments better tailored to their needs than the products that are generally available under regulation.”7

PURPA brought on a whole new era of risk management. PURPA did this simply by ushering in the era of fixed-price, performance-based PPAs. Before the power plant

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6 For our purpose here, risk is defined as variation from an expectation. We may expect natural gas prices to be $2.50/MMBtu, but there is some chance that those prices can rise abruptly to $5.00/MMBtu or fall to $1.25/MMBtu. We may expect peak demand to increase by 2,500 MW, but it may increase by 5,000 MW or not increase at all. Anticipating variation and protecting against its adverse effects is the heart of risk management. While we think about adverse effects, it is important to see risk as a symmetric concept. The uncertain outcome can be beneficial or harmful, profitable or unprofitable.

was ever built, the project developer knew what was expected. If the cost of building or operating the power plant was higher than the expectation built into the contract price, the developer automatically suffered the financial harm; if costs were lower, the developer realized the gain. If a power plant did not perform as expected, the developer simply did not get paid.

Faced with a fixed-price, performance-based PPA, a fairly standard approach to risk management took hold as depicted in Table Six. The Table takes the perspective of a power plant developer who has won a competitive bid to sell electricity under a fixed-price, performance-based PPA. Three points are notable about the PURPA-inspired, risk-management plan:

- First, significant risks were fully allocated to the developer and away from the consumer. These include development, construction, fuel, operations and maintenance (O&M), and financing risk.

- Second, the developer reallocated risk to other parties through contracts. The benefit of this reallocation is that the party best able to control a risk was assigned that risk. This minimized the overall or total risk.

- Third, under PURPA, consuming utilities took on market risk. For purposes here, market risk is defined as variation in current market prices from the power prices and level of operation prescribed in the PPA.
## TABLE SIX: RISK-MANAGEMENT OPTIONS

<table>
<thead>
<tr>
<th>Category</th>
<th>Nature of Risk</th>
<th>Regulated Utility Allocates Risk To:</th>
<th>PPA Allocates Risk To:</th>
<th>PPA Reallocations of Risk</th>
<th>Through:</th>
</tr>
</thead>
<tbody>
<tr>
<td>DEVELOPMENT RISK</td>
<td>Variations (as compared to assumptions in bid) on any and all aspects of the project: financing, constructing, O&amp;M, and fuel</td>
<td>Customer</td>
<td>Developer</td>
<td>None, developer retains</td>
<td>Engineering Procurement and Construction (EPC) contractor</td>
</tr>
<tr>
<td>CONSTRUCTION RISK</td>
<td>Variations in timing and cost of construction</td>
<td>Customer</td>
<td>Developer</td>
<td>Fuel suppliers, Fuel transporters</td>
<td>EPC agreement</td>
</tr>
<tr>
<td>FUEL RISK</td>
<td>Variations in cost and availability of fuel supply and transport</td>
<td>Customer</td>
<td>Developer</td>
<td>Fuel suppliers, Fuel transporters</td>
<td>Supply agreements, Transport agreements</td>
</tr>
<tr>
<td>O&amp;M RISK</td>
<td>Variations in operating performance and cost of operation and maintenance (O&amp;M)</td>
<td>Customer</td>
<td>Developer</td>
<td>O&amp;M contractor</td>
<td>O&amp;M agreement</td>
</tr>
<tr>
<td>FINANCING RISK</td>
<td>Variations in structure and cost of financing</td>
<td>Customer</td>
<td>Developer</td>
<td>Banks, Equity partners</td>
<td>Credit agreements, Partnership agreements</td>
</tr>
<tr>
<td>MARKET RISK</td>
<td>Variations in market demand for and market price of electricity</td>
<td>Customer</td>
<td>Utility</td>
<td>None, utility retains</td>
<td></td>
</tr>
</tbody>
</table>
Managing Market Risk

The major change in risk allocation in the late 1990s is the fact that project developers now take on market risk. That is, rather than being guaranteed a set price and level of operation, developers now accept swings in price and demand brought on by variations in market conditions. Plants accepting at least some level of market risk often are called merchant plants.

Again, the acceptance of market risk is not simply an act of bravado on the part of developers, but rather an act with a thorough risk-management plan behind it. Some developers shift at least partial market risk of a merchant plant to others through innovative fuel supply or tolling agreements. A fuel supplier may index its fuel price to the market price of electricity, thus assuring the developer a margin. A toller will often bring fuel to the power plant and take the electricity produced, thus taking on risks at both ends within limits defined by the tolling agreement. At the corporate level, developers or power marketers mitigate market risk through a portfolio of businesses diversified across markets. In this way, the corporation reduces its exposure to specific market fluctuations.

The sharp contrast between the results of a regulatory or competitive regime becomes clear when suppliers take on market risk. Take, for example, a market with excess power plant capacity. Under regulation, assuming that a prudent process was followed, consumer prices may rise because the surplus capacity is incorporated into rate base. Under competition, surplus capacity is likely to mean prices will fall.

Managing Consumer Risk

It is clear that the competitive regime has pushed risk management to new levels over the years. Project risks were the first to be addressed by risk managers and now suppliers are managing market risk. The next frontier is to allow different classes of consumers to choose risk management tailored to their own risk tolerance; we refer to this as managing consumer risk.

Clearly, all customers do not have the same tolerance for risk. For example, with respect to market price risk, some customers may have much more tolerance than others. Take a chemical manufacturer that locks in its chemical product prices for customers over a six-month period into the future. Reflected in the locked-in price is an assumption about the cost of electricity. That chemical manufacturer will want protection from the risk of electricity price increases during the six-month period. In contrast, residential consumers on a fixed budget, most likely served in aggregate by a load-serving entity, may want to be protected from price risk for at least one full year, if not for a multiyear period. The same would hold true for reliability risk, with different customers having different tolerance for interruptions and curtailment.

The frontier in risk management for the U.S. market is to tailor electricity supply offers to the risk needs of individual consumers. Competitive power suppliers are ready,
willing and able to do so for large customers. For instance, electric rate swaps are available for industrial customers that want to protect themselves from a utility rate that includes a large fuel adjustment mechanism. Electric rate swaps are a price risk-management tool that allows a customer to have its electric bill paid for by a “counterparty” for a fee. In practice, this means that any party (utility or electric customer) that does not want to be subject to a “fluctuating” rate can exchange it for a “fixed” rate via the market. Thus, the needs of both “fluctuating” and “fixed” rate customers are satisfied.

Another form of price risk management is energy outsourcing programs in which a supplier or marketer will manage the energy requirements of a commercial/industrial customer for a fixed price. Implicit in this arrangement is that the supplier bears the burden of market risk by insulating the commercial/industrial customer from market volatility and also savings in energy costs. The primary benefit of this arrangement is that it allows the commercial/industrial customer to concentrate on its core business instead of diverting resources to energy management.

Risk products tailored to smaller customers’ individual needs at the retail level have yet to become commonplace. However, there is good reason to believe such products would emerge given the opportunity. This already is the case with industries such as telecommunications, in which customers are offered a wide variety of rates, calling plans, and bundled services. Telecommunications customers can choose the products based on their preferences and services required.

A Note on Risk Management in California

Events in California occurred not because of new risks introduced by competition, but because market rules blocked utilities from conducting the most basic risk management. By law, utilities had to sell at a fixed price to consumers but buy at a variable price in the state’s spot market. It was inevitable that the two prices would get out of line. That is what initially left the state with no creditworthy buyers. Even the most rudimentary risk-management analysis would show that the utilities must match the fixed-price sales with fixed-price supply contracts.

If prudence review associated with a regulatory regime did anything in this situation, it only made matters worse. Even if allowed to manage risks through supply contracts, California’s utilities would be reluctant to do so because after-the-fact prudence review might bring disallowances. It is ironic that the problems in California have led to a longing for “the good old days” of cost-plus regulation when, in fact, prudence reviews in that cost-plus regime contributed to these problems.
A NOTE ON RELIABILITY RISK

The scope of this report is limited to price performance and the potential for price risk management under competition, but clearly an examination of reliability risk under competition is needed for a complete picture. Although not meant to be a complete analysis, the anecdotal evidence that follows would imply that reliability could be enhanced with increasing competition. First, independent power producers (IPPs) have been quick to build new plants in markets where there is an accommodating regulatory climate; Texas is a good example of this. Second, IPPs have historically established a track record of high levels of availability with newly built plants, further strengthening reliability. Third, even when IPPs have taken over older, utility-built power plants, they have improved their performance markedly.

IPPs and Business-Friendly Markets

Peak load is comparable in Texas and California. Texas is not experiencing shortages as in California, however, because Texas has adequate supply. Indeed, The Wall Street Journal recently reported that Texas may face an oversupply of electricity since its “business-friendly approach to deregulating its power industry,” with flexible environmental and zoning regulations among other factors, “set off a flurry of power plant construction.” This flurry of power plant construction has permitted the Public Utility Commission of Texas to note in its 2001 report to the state legislature that reserve margins are expected to be 30 percent, or 16,291 MW, for 2001.

Sufficient supply is due largely to aggressive development by independent generators. According to the Texas Public Utility Commission, approximately 9,343 MW of capacity were built between 1996 and March 2001, and currently about 13,991 MW is under construction. Contrast Texas with California. With regard to reserve margins, the California Independent System Operator (CAISO) expects resource deficiencies for this summer, which may be up to 3,647 MW. The California Energy Commission (CEC), the lead agency for approving power plant construction, did not approve any plants from March 1996 through April 1999. Between April 1999 and the present, 9,874 MW of power plants were approved, of which 1,829 MW were planned to


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be online by August 2001. However, even CEC officials admit that few of these planned MW will be ready by this summer.

**IPPs Have a Track Record of High Availability Factors**

Independent developers have an established track record for building plants that perform well. In the early 1990s, when the issue of reliability first arose, General Electric calculated availability factors for IPP projects that used its equipment for each of the five years from 1988 to 1992. Availability factors for the projects on average were above 90 percent for all five years. Similarly, the Gulf Coast Cogeneration Association’s 1991 survey, covering projects totaling 5,714 MW of capacity in Texas and Louisiana, found that the projects maintained a median availability factor of 95 percent over their lifetimes.

**IPPs Can Improve Performance**

Even when IPPs have taken over older utility-built power plants, they have improved their performance markedly. For instance, a recent report by FERC staff on plant outages in California showed dramatic increases in capacity factors at plants that were divested by utilities and bought by IPPs. The plants examined in the report were purchased by IPPs from Southern California Edison (SCE) or Pacific Gas and Electric (PG&E) in 1998, and the average age of the plants was 32 years. Under utility ownership, plants were used less and minimally maintained in preparation for divestiture. About one plant, the FERC report states “it was used with decreasing frequency by Southern California Edison before it was sold in April 1998.” In some cases the new IPP owners had to make up for years of neglect. “Prior to the sale of the El Segundo units to West Coast, SCE performed minimal maintenance on these units. [The plant manager] indicated that SCE gave up maintaining the plant ten years ago. . . . NRG started overhauling the equipment upon its ownership.”

IPP owners were successful in refurbishing and operating the plants to significantly increase their capacity factors. For instance, the Etiwanda plant had capacity factors of approximately 8 percent to 9 percent for Unit 3 and 12 percent for Unit 4 in 1998. For the period January to October 2000, capacity factors had risen to 38 percent and 37 percent, respectively. A capacity factor is the actual output as a percent of the

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12 http://www.energy.ca.gov/sitingcases/approved.html.
16 Ibid. p. 41.
17 Ibid. p. 20.
maximum possible. Rising capacity factors show increased need for energy in California but also an increase in the ability of the plant to provide more energy. Even if we don’t take into account the high load levels in 2000, capacity factors were gradually moving up over the period from 1998 to 2000. The El Segundo plant near Manhattan Beach illustrated similar improvements between 1998 and 1999. In 1998, capacity factors for Units 3 and 4 were approximately 14 percent and 21 percent, respectively. By 2000, they had risen to 29 percent and 43 percent.\(^{18}\)

\(^{18}\) Ibid. p. 40.